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FOREWORD

The introduction of nuclear power into the electricity generation grid of a country poses specific requirements to the national infrastructure that largely surpass those experienced in general industrial and energy development planning. The relatively high expenditures associated with the construction of a nuclear power plant, and the implications for the country and the power utility involved, require that any decision for introduction of this technology be a sound one. Consequently, when consideration is given to the possible introduction of nuclear power, it is important to carefully assess future energy supply and demand, economic and financial implications, and requirements for infrastructure development and technology transfer.

In accordance with its mandate of promoting nuclear technology for peaceful applications worldwide, the IAEA offers to its Member States a comprehensive programme of technical assistance and co-operation (TCAC), which covers many diverse areas related to peaceful uses of nuclear energy. In the area of nuclear power planning, the overall objective of assistance is to help strengthen national capabilities for: analysing projections of overall energy and electricity demand; planning the possible role of nuclear power in electricity supply through the determination of the economically optimal extent and schedule for the introduction of nuclear power plants; assessing the available infrastructures and the associated needs, constraints and possibilities for their development; and developing schedules, programmes and recommendations for action.

The TCAC programme of the IAEA includes assistance for energy and nuclear power planning (ENPP) studies which aim to determine the appropriate role that nuclear power could play in satisfying the future electricity generation requirements of a country, which is consistent with the national objectives for socioeconomic and technical development, and the possibilities of the country to achieve these goals. ENPP studies are carried out by the IAEA in co-operation with requesting Member States with a precise scope, organization and duration. This type of study involves the application of several IAEA planning models and has as its ultimate objective to enhance the planning capabilities of the country.

In 1993, the Cabinet Committee on Energy in Pakistan directed the Pakistan Atomic Energy Commission (PAEC) to initiate studies to assess the appropriate role of nuclear power in meeting the future electricity needs of the country. To assist in this endeavour, a national technical co-operation project on Energy and Nuclear Power Planning for Pakistan was initiated by the IAEA in 1994. The study focused on identifying the economically optimal share of nuclear power in the future electricity generation mix of the country, assessing the environmental impacts of such a development of the electricity generating system, and analysing the financial viability of the envisaged nuclear power development programme.

The current study demonstrates how the IAEA's integrated set of energy planning tools can be utilized for comprehensive national analyses involving the use of: (i) MAED for analysis of energy demand, (ii) BALANCE for investigation into the market-based allocation of energy resources to power and non-power sectors, (iii) WASP for formulation of least-cost power capacity expansion plans, (iv) IMPACTS for assessment of environmental impacts associated with different electricity system expansion strategies, and (v) FINPLAN for financial analysis of the envisaged nuclear power development plan.

The ENPP study for Pakistan is unique in the sense that all of the models developed by the IAEA for energy, electricity and nuclear power planning were used in the study. As such, the present publication is intended to document a good example of an ENPP study and to serve as guidance for similar studies that the IAEA may undertake with other Member States in the future.

Since many of the assumptions made for the study are the result of expert consensus but have not been validated or endorsed by the Government, the present results should not be considered to be the energy and electricity master plan of Pakistan. Likewise, the expansion plans of the electricity supply system delineated by the study should not be taken as the Government plan in this area. The findings of the study do, however, provide insights into possible strategies for developing the power generating system and the necessary work to be undertaken to supplement the results of the study or to update it if deviations are experienced in the principal hypotheses made for the study.

Finally, it should be noted that PAEC was fully responsible for all phases of the study, including the preparation of the present report. The IAEA's role was to provide overall co-ordination and guidance throughout the conduct of the study, and to guarantee that adequate training in the use of IAEA planning models was provided to the members of the national team, both through their attendance of regular training courses on the subject matter and during several meetings organized within the scope of the project. The IAEA staff officer responsible for this publication was B. Hamilton of the Division of Nuclear Power.

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SUMMARY

1. *Objectives and Scope of the Study*

The Cabinet Committee on Energy directed Pakistan Atomic Energy Commission (PAEC) in 1993 to initiate studies to assess a realistic role of nuclear power in the future electricity generation mix of Pakistan for the 9th Five Year Plan period (1998–2003) and beyond. In pursuance of this directive, PAEC has conducted a detailed study on Energy and Nuclear Power Planning for Pakistan with the time horizon up to 2023. The main objectives of this study are:

- To identify the optimum share of nuclear power in the future mix of electricity generation on the basis of least-cost analysis of the expansion of electricity system,
- To assess the environmental impacts of such a nuclear power development, and
- To analyse the financial viability of the envisaged nuclear power development programme.

2. Organization of the Study

The study has been conducted by the Applied Systems Analysis Group (ASAG) of PAEC with technical assistance from the International Atomic Energy Agency (IAEA). A number of Expert Missions were arranged by the IAEA for providing technical assistance to the national team for the conduct of this study. In addition, the IAEA provided training to the members of the national team on the use of various computer based planning models used for the analysis of various aspects of energy and electricity planning. Experts from various national organizations related to the energy sector and the Planning and Development Division, Government of Pakistan, provided overall guidance to the national team during the course of the study. The study was initiated in early 1994 and has been completed in about two years, as envisaged.

3. Methodological Approach

Nuclear power is one of the several technological options available for producing electricity. The future role of nuclear power can only be determined if the future development of the electricity sector is analysed in detail by considering the expected future requirements of electricity and all possible supply options. Further, since electricity may substitute other fuels for some of the categories of energy end-use and the electricity generation has to compete with energy demand in other sectors for the available primary energy supplies, it is desirable to analyse the evolution of energy demand and supply for the entire energy system at the national level. Such an integrated approach is provided in the set of planning methodologies developed by the IAEA. The various models used for carrying out this study are: (i) MAED for energy and electricity demand analysis and projections, (ii) BALANCE for energy resources allocation to power and non-power sectors, (iii) ELECTRIC (WASP-III plus) for formulation of least-cost power capacity expansion plans, (iv) IMPACTS for assessment of environmental impacts of alternative plans for electricity generation systems, and (v) FINPLAN for financial analysis of the envisaged nuclear power development plan. All these models are inter-linked with each other to ensure consistency and to provide feed-back information from one model to another. The use of these models, however, requires development of scenarios with consistent assumptions on evolution of demography, economy, technology development, energy resource development, future prices and costs, etc. Table 1 lists the scenarios developed for this study and the main building blocks for each scenario. The major assumptions for these scenarios are summarized in the following section.

4. Major Assumptions

4.1. Demography

Population growth is one of the important factors determining the future evolution of energy and electricity demand. For the present study, in line with official projections for the 8th Five Year Plan and the Perspective Plan, the population growth has been assumed to decline gradually from the present level of 2.9% per annum to 2.1% p.a. by the year 2008 and further down to 1.7% p.a. by the year 2023. According to these assumptions the population of Pakistan in 2023 will become about 235 million. Other demographic parameters, such as urbanization rate, living standard of the population, etc. have been linked with the assumed economic activity for different scenarios.

4.2. Economy

The level of economic activity and the structure of the economy are the most important factors for projecting the future energy and electricity demand. The official targets for economic growth during the 8th Five year Plan period (1993-1998) and the Perspective Plan period (1993-2008) have been set as 7% per annum. However, some development economists believe that even higher economic growth (8-9% p.a.) can be achieved if the economic and trade policies are made more liberal. Keeping in view the perspectives of the Planning Commission, Government of Pakistan, and the projections by the World Bank and the Organization for Economic Cooperation and Development (OECD) for developing countries, three scenarios for the growth of national economy have been developed for this study. Figure 1 shows the overall growth of GDP assumed in these scenarios and Fig. 2 compares the corresponding evolution of GDP per capita.

4.3. Indigenous Energy Resource Development

The petroleum exploration activity has been assumed to increase considerably with the result that the indigenous production of oil and gas increases from 2.9 million TOE for oil and 12.4 million TOE for gas in 1993 to 11.5 million TOE and 45.1 million TOE respectively by the year 2023. As for coal, it has been assumed that the recently identified coal field at Thar will be developed to support some 10-15 GW of coal fired power generation capacity. In the case of hydro power, it has been assumed that in addition to presently under-construction and planned hydro projects, two large hydro power plants (possibly Kalabagh and Basha) with some 6 000 MW installed capacity could be constructed. As for nuclear power, it has been assumed that in addition to the under construction Chashma Nuclear Power Project, additional nuclear power plants will be built in the country.

4.4. Energy Imports

In view of the limited potential of energy supplies from indigenous resources, it has been assumed that coal, oil and gas will be imported to meet the future energy requirements. Keeping in view the present plans, three gas pipelines from Qatar, Iran and Turkemanistan have been considered. It has been assumed that one of these gas pipelines will become operational by the turn of this century while the other two would be available after a gap of a few years. Coal imports have been considered for power generation for plants to be located close to coastal areas. Siting limitations and environmental considerations, besides economics, will determine the power capacity additions based on imported coal. Oil imports have been assumed to fill up the gap between supplies from all sources and the projected energy demand.

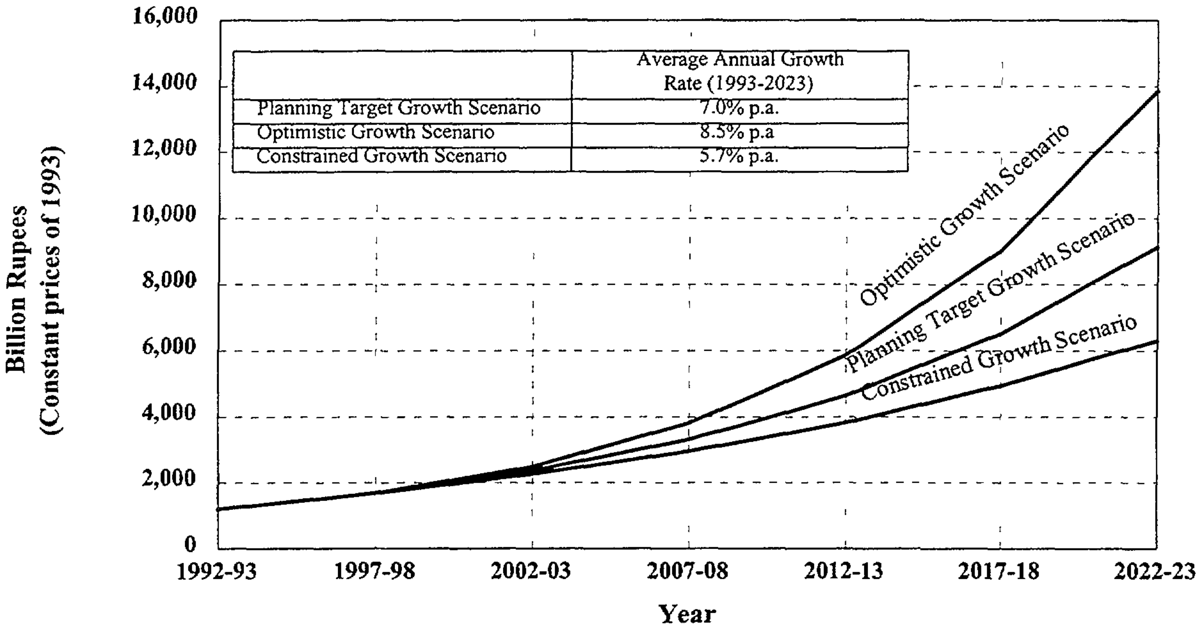


FIG. 1. GDP in Three Economic Growth Scenarios

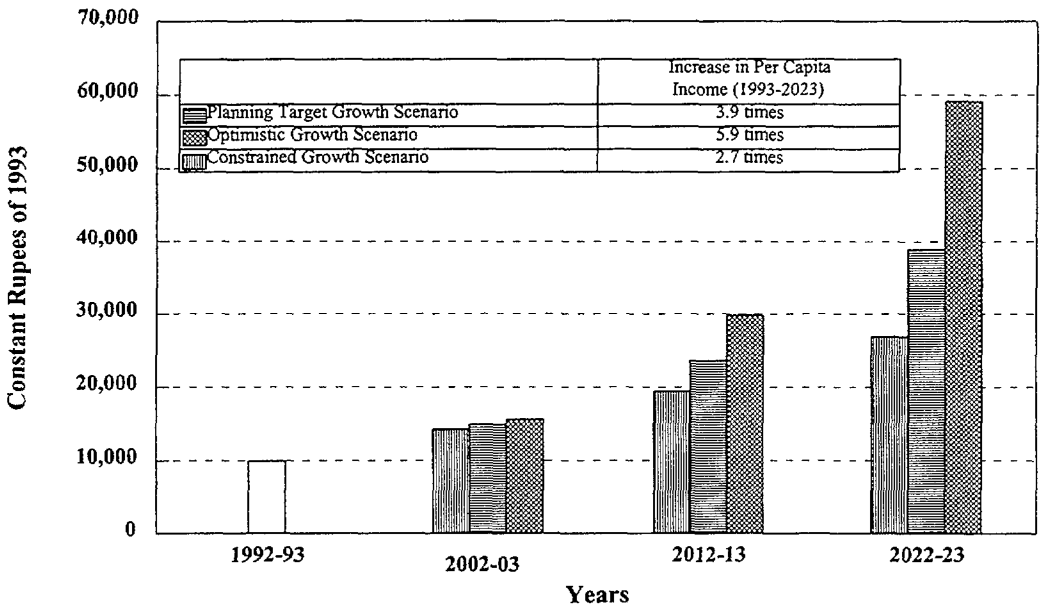


FIG. 2. Evolution of GDP per Capita in Three Economic Growth Scenarios

Table 1. Summary of Analyses Reported in this Study

Scenario/Case Building Blocks	Energy and Electricity Demand Analysis Cases	Energy Supply Analysis Cases	Electric System Expansion Analysis Cases	Environmental Analysis* Cases	Financial Analysis Case
A. Economic Growth A1 Planning target growth scenario A2 Optimistic growth scenario A3 Constrained growth scenario **B. Demography** Population growth projections are common in all the scenarios Some of the parameters have been assumed to change with economic growth scenario **C. Energy Efficiency Cases** C1 Nominal energy efficiency improvement case C2 Vigorous energy efficiency improvement case **D. Indigenous Energy Resource Development** Development of oil, gas and hydro resources is common in all the energy supply and electric system expansion cases The development of coal resources has been assumed to be more rapid in Optimistic Case/Alternative IV **E. Gas Imports Cases** E1 Gas import allowed E2 Gas imports not allowed **F. Nuclear Power Development Cases** F1 Gradual development of nuclear power F2 No further development of nuclear power **G. Energy Price Scenarios** 1 An increase of 70% in real terms assumed in oil and gas prices and 35% in coal prices over the 30 year period 2 Prices to remain constant in real terms (for sensitivity analysis only)	1. **Reference Scenario** (Combination of A1 & C1) 2. **Optimistic Scenario** (Combination of A2 & C1) 3. **Constrained Scenario** (Combination of A3 & C1) 4. **Energy Efficiency Scenario** (Combination of A1 & C2)	1. **Gas Imports Case** (Reference scenario of energy demand with E1 & F1) 2. **No Gas Imports Case** (Reference scenario of energy demand with E2 & F1)	1. **Reference Case** (Reference scenario of electricity demand with E1 & F1) 2. **Nuclear Moratorium** Case/ Alternative I (Reference scenario of electricity demand with E1 & F2) 3. **No Gas Imports Case/ Alternative II** (Reference scenario of electricity demand with E2 & F1) 4. **Energy Efficiency Case/ Alternative III** (Energy efficiency scenario of electricity demand with E1 & F1) 5. **Optimistic Case/ Alternative IV** (Optimistic scenario of electricity demand with E1 & F1) 6. **Alternative V** (Reference Case with private sector plants)	1. **Case 1** (Reference Case of Electric System Expansion Analysis) 2. **Case 2** (Nuclear moratorium case of electric system expansion analysis) 3. **Case 3** (Nuclear moratorium case of electric system expansion analysis with air pollution control devices added to some of the coal and oil fired power plants to bring down the emissions of SO_2 and NO_x to the levels of the Case 1)	Financial analysis of nuclear power development programme of the **Reference case** of electric system expansion analysis, and sensitivity analysis of the results with respect to i) increased capital cost ii) higher foreign interest rate iii) rapid deterioration of exchange rate iv) lower price of electricity sales

* Environmental analysis has been carried out for the power sector only

4.5. Fuel Prices

In line with a number of recent projections by various international agencies, it has been assumed for the present study that the imported oil prices will increase in real terms at 1% per annum till the year 2000, at 2% per annum during 2000-2010 and at 2.7% per annum thereafter. The price of imported gas has been assumed to follow the trend assumed for oil prices. For imported coal price, a 1% per annum increase in real terms has been assumed throughout the planning period. As for prices of indigenous fuels, in line with government policy, these have been linked with the prices of imported fuels.

5. Main Findings

5.1. Energy and Electricity Demand

Four scenarios of future demand for energy and electricity have been developed which correspond to different levels assumed for future economic growth and energy efficiency improvements. Figure 3 shows the evolution of final commercial energy demand in these scenarios.

Corresponding to the above energy scenarios the future demand for electricity has been projected to grow at 7-11% p.a. as shown in Table 2.

The increase in the per capita electricity consumption in different scenarios is shown in Fig. 4. Despite considerable increase by the year 2023, the per capita consumption level in Pakistan, in the Reference Scenario, will still be only 1/4th of the present average for the OECD countries.

The peak demand corresponding to above projections at the end of 9th Five Year Plan and at the end of planning horizon are given in Table 3.

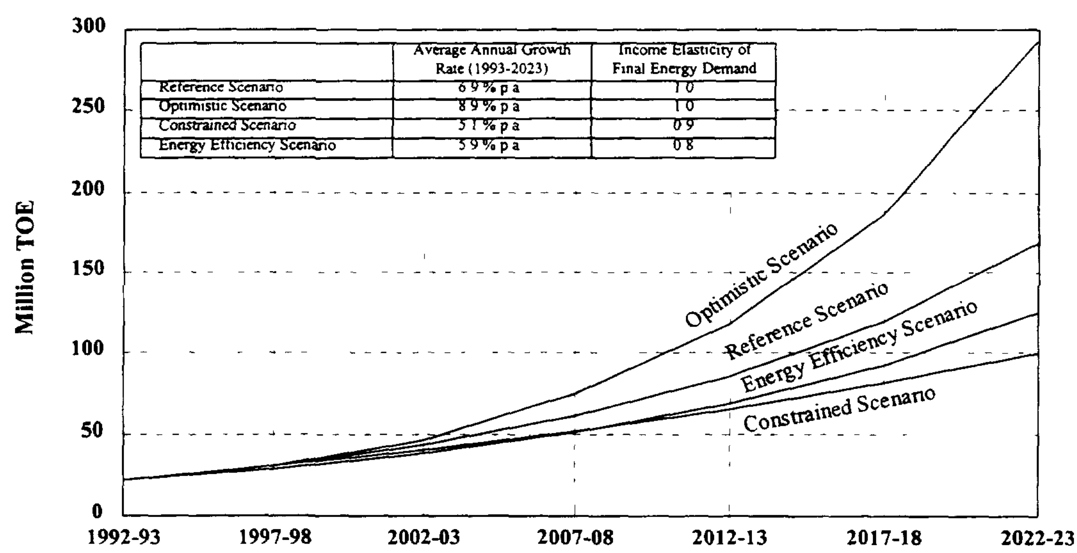


FIG. 3. Projection of Final Energy Demand in Different Scenarios

Table 2. Projected Growth Rates of Electricity Consumption in Four Energy Demand Scenarios

Demand Scenario	Growth Rate of Electricity Consumption (per annum)	
	1993-2003	1993-2023
Reference Scenario	8.9%	8.7%
Optimistic Scenario	9.6%	10.6%
Constrained Scenario	8.1%	6.9%
Energy Efficiency Scenario	8.3%	8.0%

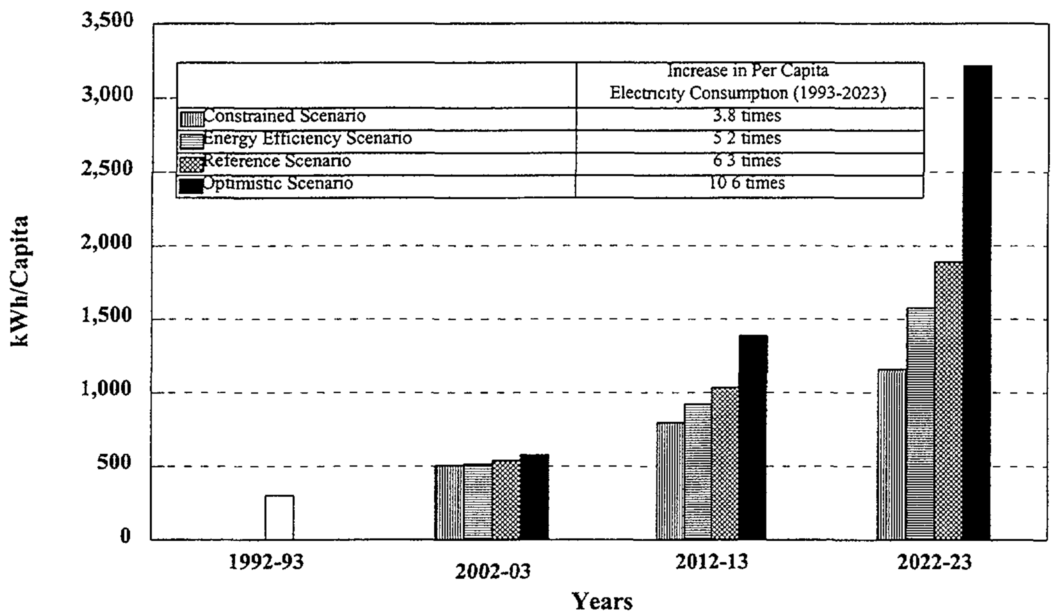


FIG. 4. Evolution of Electricity Consumption per Capita in Four Energy Demand Scenarios

Table 3. Projection of Peak Demand for the Four Energy Demand Scenarios

Demand Scenario	Peak Demand	
	2003	2023
Reference Scenario	16 025 MW	83 550 MW
Optimistic Scenario	17 220 MW	146 040 MW
Constrained Scenario	14 925 MW	49 415 MW
Energy Efficiency Scenario	15 020 MW	67 485 MW

The net power generation capacity additions over the 30 years study period will range from 68 000 to 147 000 MW in different scenarios. Such a large capacity addition will not only require large investments and commitment of other resources, it will also result in heavy environmental burden if appropriate measures are not taken.

5.2. Overall Energy Demand-Supply Balance

In order to meet the projected energy demand, it is expected that the country will continue to be dependent on energy imports. The energy import dependence, in the Reference Scenario, will remain within 32-38% of the total primary energy requirements during the next 20 years but will increase further thereafter, reaching about 48% at the end of the planning horizon. This is despite the fact that a considerably large increase has been assumed in the future supplies from indigenous energy resources as described in Section 4.3. The contribution of nuclear power in total primary energy supplies has been estimated to increase from 0.3% now to 2.6% at the end of 9th Five Year Plan (2003) and to about 9% at the end of planning horizon (2023).

If the future energy demand happens to be as projected in the Optimistic Scenario then the energy import dependence will reach a level of about 70% by the end of planning horizon. However, if the future energy demand turns out to be as projected in the Constrained Scenario or Energy Efficiency Scenario, the energy import dependence will slightly decrease from the present level of 34% to about 30%.

5.3. Least-Cost Plan for Expansion of the Electricity Generation System

Counting for the retirement of older plants, a total of 83 100 MW of power generation capacity has to be added over the period 1993 to 2022 to meet the electricity demand as projected in the Reference Scenario. Due to limitations on the pace of development of hydro power and nuclear power, a large fraction of the capacity addition will have to be based on fossil fuels. The mix of required installed capacity as determined in the least cost plan for the Reference Scenario is given in Table 4.

The contribution of nuclear power in total capacity additions is 13 200 MW, which remains unchanged under wide variation of certain important parameters, for example capital cost, discount rate and prices of alternative fuels. The contribution of various sources in the future power generation capacity for the least cost expansion plan in the Reference Case is shown in Fig. 5.

Table 4. Projected Installed Generation Capacity Mix for the Reference Scenario

	2003	2022
Hydro	6 662 MW	14 502 MW
Gas	6 364 MW	29 216 MW
Coal	1 162 MW	16 150 MW
Oil	5 113 MW	18 222 MW
Nuclear	1 050 MW	13 525 MW
Total	20 351 MW	91 615 MW

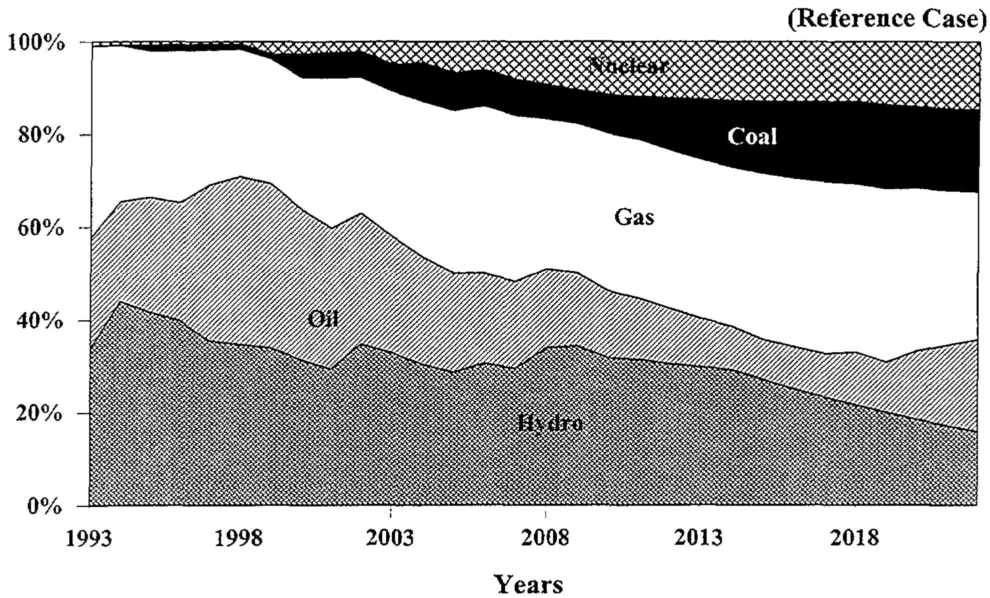


FIG. 5. Future Electricity Generation Capacity Mix By Fuel

Table 5. Alternative Expansion Plans For Electricity Generation System

Alternative Cases	Major variations with respect to Reference Case	Effects of variation
Alternative I	A moratorium on further development of nuclear power	Nuclear power plants replaced by oil-fired plants; higher oil import dependence, increased environmental degradation
Alternative II	Import of gas not allowed	Gas fired plants replaced by oil-fired plants
Alternative III	Demand scenario with high energy efficiency	17% lower demand, still all nuclear power plants selected in the optimal solution.
Alternative IV	Optimistic demand scenario	147 000 MW of additional power capacity required compared to 84 000 MW in the Reference case, larger investments and very high import dependence.
Alternative V	Private power plants included as committed plants	First nuclear power plant shifted by one year and some of the combined cycle plants also delayed.

5.4. Alternative Plans for Expansion of Electricity Generation System

In order to analyse the main uncertainties surrounding the future development of the electric sector in Pakistan, a number of alternative plans for future expansion of the electricity generation system have been formulated and analysed. The major variations among the alternative cases and the corresponding effects are summarized in Table 5.

5.5. Investment Requirements

The total investment required over the 30 year period for building up the electricity generation system proposed in the Reference Case has been estimated as US $ 108 billion (in 1993 prices). This investment is some US $ 15 billion higher compared to the one required for the case with nuclear moratorium. But if the system operation costs (fuel and O&M costs) are also taken into account then the generation system of the Reference Case becomes economically attractive. The cumulative cost, over the 30 year planning horizon, for system operation in the Reference case is US $ 172 billion compared to US $ 205 billion in the nuclear moratorium case. Further, the energy import dependence of the country in the Reference Case is lower by some 10 percentage points compared to that in the case without nuclear power.

The total investment required for building the electricity generation system for meeting the demand projected for the Energy Efficiency Scenario is some 17% lower compared to that for the Reference Case. Although, the investment required to implement the energy efficiency measures has not been estimated in this study, it is felt this would be significantly lower than the cost of avoided capacity additions.

5.6. Environmental Assessment

The environmental analysis of alternative plans for the expansion of electricity generation system shows that irrespective of the mix of future electricity generation system, the environmental burdens in Pakistan imposed by the electric sector will increase by a factor of about ten. However, the electricity generation system of the Reference Case is the cleanest system because of inclusion of nuclear power plants which do not emit any of the noxious gases like SO_2, NO_X, CO_2, etc. The radioactive emissions from nuclear power plants are kept well within the permissible limits specified by the international organizations and are generally much lower compared to that emitted by coal fired plants (the coal fired plants are not equipped with any system for containing the radioactive elements present in the coal). Further, if pollution control devices are added to the fossil fuel fired plants, it has been estimated that the investment and operation costs of such devices will increase the overall cost giving again a significant margin to nuclear power.

5.7. Financial Analysis

The financial analysis of the envisaged nuclear power development plan shows that the plan is financially viable on technical grounds, under financing terms assumed in line with the internationally accepted practices and the recent policy of the government for private power producers in Pakistan. However, there may be other considerations (such as political) which may affect the availability of financial resources for the envisaged nuclear power development plan. For the first nuclear power plant, it has been assumed that the government will provide equity to the extent of 22% of the investment and the remaining funds will be generated from foreign and local loans. However, as the nuclear power plants become operational and start generating revenues, the surplus earnings, available after meeting all operational costs, debt servicing and dividend payment, can be used for investment in future plants. These earnings after about 15 years will become sufficient to cover almost 100% of the investment required for the subsequent plants.

6. Conclusions and Recommendations

The detailed analyses carried out in this study show that the demand for energy and electricity will continue to increase in the coming years at about 7% and 9% per annum respectively, and that the future supplies from indigenous energy resources will remain inadequate to meet the projected demand. As such, the country will continue to be dependent on imported fuels. Furthermore, due to increased use of energy, the environmental emissions from the energy sector will increase many folds, threatening severe degradation of natural environment. In order to combat these problems, the study has shown that the following measures should be taken:

- Vigorous efforts should be made to increase efficiency of energy and electricity use in all sectors of the economy by encouraging the use of efficient appliances and avoiding wasteful uses through appropriate fiscal and regulatory measures. Besides, concerted efforts should be made to implement the plans for reduction in transmission and distribution losses of electricity.

- Additional indigenous energy resources should be explored and rapidly developed with greater emphasis on oil and gas which are expected to remain the major sources of energy supplies in the coming years. The recently identified large coal deposit, Thar, should be developed and put to use in an environmentally acceptable manner. Additional hydro power resource should be developed as fast as possible.

- Concerted efforts should be made to construct additional nuclear power plants in order to reduce the energy import dependence of the country and to avoid excessive degradation of natural environment. Based on the analysis of various alternative scenarios, it is recommended that construction of a 600 MW nuclear power plant should be started in the current Five Year Plan period and of 2-3 more nuclear plants in the 9th Five Year Plan period. Thereafter, nuclear power plants should be built at regular intervals in accordance with the maximum technically feasible limits. The Government should provide financial support for the first few nuclear power plants, which will generate sufficient surplus income during operation to cover the investment requirements of the subsequent plants.

- Systematic efforts should be initiated to gradually indigenize nuclear power technology in order to implement the envisaged nuclear power development programme in a self-reliant manner. This will reduce foreign dependence for construction of future nuclear as well as thermal power plants and will effectively expand the overall industrial base of the country. In this respect, a detailed national plan should be worked out for development of the necessary infrastructure facilities for design and engineering, manufacturing, construction and installation of nuclear power plants. Further, the manpower requirements and the organizational structure for implementation of the nuclear power programme should be assessed and developed.

- A 300 MW nuclear power plant is presently under construction at the Chashma site which can accommodate up to 10 more units. However, for reasons of phased development and

- A 300 MW nuclear power plant is presently under construction at the Chashma site which can accommodate up to 10 more units. However, for reasons of phased development and grid requirement, it would be expedient to identify and thoroughly investigate additional sites in the country. Studies should, therefore, be initiated for identification and investigation of new sites for construction of future nuclear power plants.

- Since the power sector has been opened to private investors for construction of fossil fuel based and hydro power plants, it would also be desirable to encourage private investors to participate, as partners of the public sector, for the construction of nuclear power plants.

- During the course of this study the Applied Systems Analysis Group has acquired very valuable expertise on energy, electricity and nuclear power planning. This capability will be used in future planning studies by PAEC and can also be utilized by other energy planning organizations in Pakistan.

Chapter 1

INTRODUCTION

1.1. Purpose and Scope of the Study

1.1.1. Background

In 1993, the Cabinet Committee on Energy, the highest decision making body in Pakistan on energy matters, directed Pakistan Atomic Energy Commission (PAEC) to initiate studies to assess a realistic role of nuclear power in the future electricity generation mix of Pakistan for the 9th Five Year Plan period (1998–2003) and beyond. After careful evaluation of various possibilities, it was decided to carry out a long term study with technical assistance of IAEA. Consequently, the IAEA was approached with a formal request to assist PAEC in this task under the Agency's Technical Cooperation Programme. The Agency responded positively to PAEC's request and the Technical Cooperation Project PAK/0/006 was initiated in February 1994. The Applied Systems Analysis Group (ASAG) in PAEC was made responsible for conducting the study with technical assistance of IAEA' Experts. A number of national experts from energy related organizations and the Ministry of Finance provided guidance to the national team for the conduct of study.

1.1.2. Objectives of the Study

The specific objectives identified for the study, which laid down the basis for its scope, are as follows:

i) To identify the optimum share of nuclear power in the future electricity supply mix of Pakistan on the basis of a least-cost expansion planning analysis of the country's power system,

ii) To analyse the environmental impacts of such a nuclear power development, and

iii) To establish the financial viability of the envisaged nuclear power development programme.

1.1.3. Scope of the Study

To achieve the above mentioned objectives, it was felt that the study should include:

- a detailed analysis of overall energy demand, including electricity, and its future evolution,
- assessment of future supply potential of indigenous energy resources,
- analysis of possibilities of import of various fuels,
- evaluation of future options for electricity generation,
- formulation of alternative expansion plans for electric sector development,
- assessment of environmental impacts of future electricity generation, and
- analysis of the financial requirements of the envisaged nuclear power programmes.

Further, in view of the long term implications of electricity sector development (due to long gestation times for different power plants and their long operating lives) a 30 year time horizon was considered appropriate for the study. The base year as a reference has been chosen as 1992–93 fiscal year because large amount of data required for various analyses are available for this year.

1.2. Institutional Setup and Process for Energy and Electricity Planning

The Energy Wing of the Planning and Development Division is responsible for the development of short, medium and long term plans for the energy sector. It interacts with various departments dealing with different energy sources and develops the overall national energy plan. The energy plans are worked out within the framework of the national macro-economic development plans. Like other sectors of the economy, the energy sector has to compete for resources under the development planning process. In principle, from strictly economic view point, the investment allocations for different sectors should be determined on the basis of economic efficiency. However, consistent with the objectives of socioeconomic development of the nation, sectoral shares are determined on the basis of social marginal productivity, although the detailed analysis required for this is not always possible since the resources are not always given and resource mobilization is also based on the requirement. The practical approach followed, therefore, is to determine the project wise investment requirements under each sector and then to aggregate these to determine the overall plan requirements. It is evident that in this process, development of sectoral plans is an important exercise in development planning.

As for specific energy forms, the Federal Ministry of Petroleum and Natural Resources is responsible for planning and implementation of development programmes related to all fossil fuels, including oil, gas and coal. However, since coal is a provincial matter, the mineral development departments in each province oversee and implement policies in respect of coal development, particularly regarding leasing of land for coal exploration. The federal ministry of Petroleum and Natural Resources is also responsible for development and dissemination of new and renewable energy technologies. This responsibility is carried out through its Directorate General of New and Renewable Energy Resources (DGNRER).

The Federal Ministry of Water and Power is responsible for planning and policy formulation for the electricity sector. There are two power utilities in the country, Water and Power development Authority (WAPDA) and Karachi Electric Supply Corporation (KESC), which prepare plans for their respective areas of service and implement them after approval by the Cabinet. Nuclear power is the responsibility of the PAEC, which is directly responsible to the Prime Minister. Figure 1.1 shows the ministries and departments related to the energy sector.

1.3. Methodological Approach

Nuclear power is one of the various technological options for producing electricity. The future role of nuclear power can only be determined if the future development of the electricity sector is analysed in detail, considering future requirements of electricity and all possible supply options. However, the electricity sector, in turn, is an integral part of the overall energy system because, on the one hand, at the end use level electricity may substitute other fuels for some categories of energy end-use and, on the other, electricity generation competes with energy demand in other sectors for the available primary energy supplies. As such, for a realistic analysis, it is necessary to analyse the evolution of demand and supply of the whole energy system at the national level. Further, future supply potential of all indigenous energy resources as well as import possibilities of various fuels have to be analysed. Based on the above analysis, the least-cost analysis

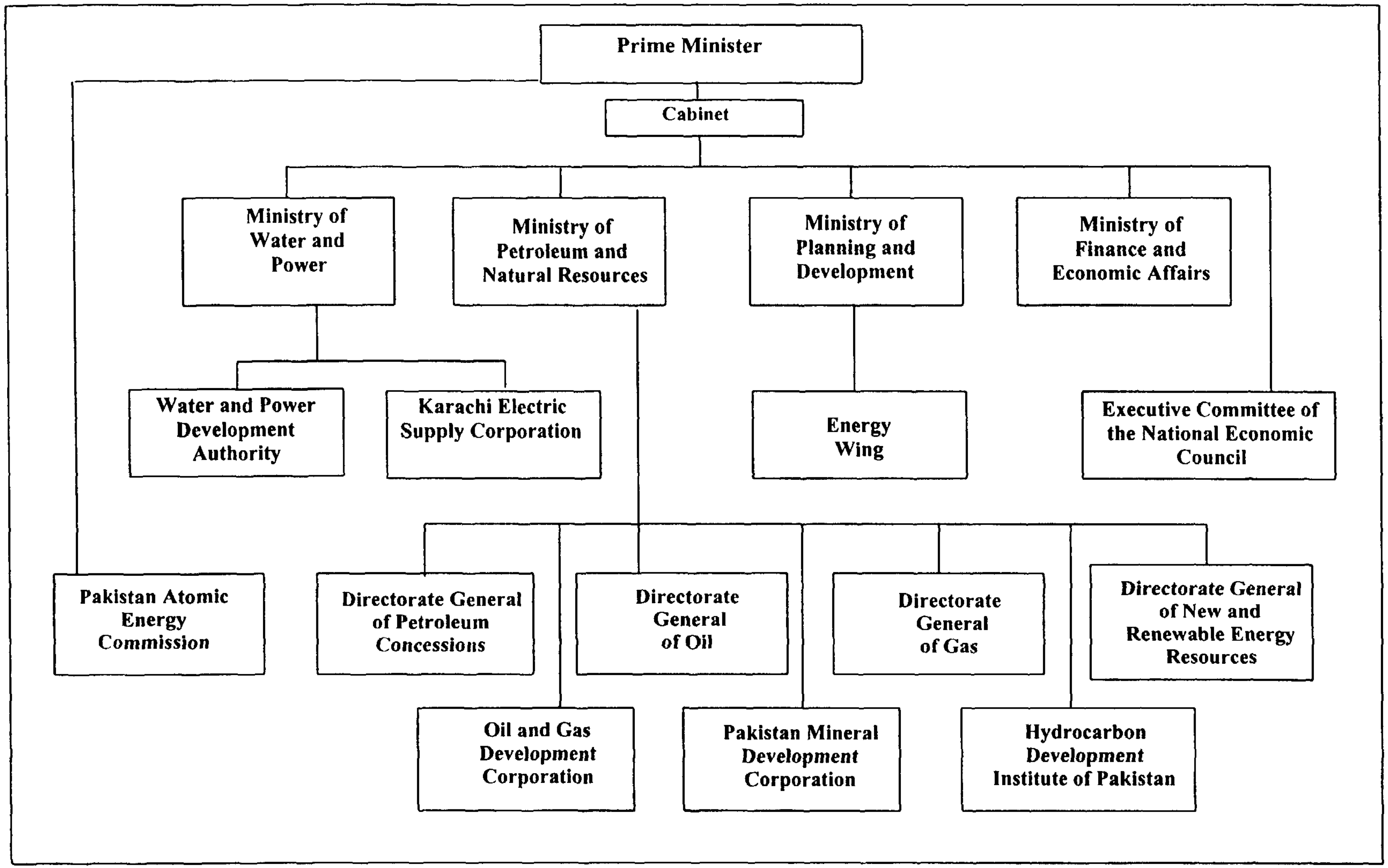


FIG. 1.1. Energy Policy and Planning Institutions

of alternative strategies for electric system expansion can be done and the possible role of nuclear power in the future electricity mix of the country can be determined. This approach has been followed in the present study.

In recent years, environmental concerns have been gaining increasing importance in Pakistan. As per a recent government regulation, the proposals for all development projects have to include an Environmental Impact Assessment (EIA) statement. The Federal and Provincial Environmental Protection Agencies are responsible for evaluating the EIA statements. As such, it has been decided to include in the present study environmental analysis of the electric system expansion plans.

The financial resources of Pakistan, like in other developing countries, are very limited. Although, nuclear power is competitive compared to other electricity generation options, it is a very capital intensive technology. A realistic programme for nuclear power development should be financially viable for the country. The present study, thus, includes financial analysis of the envisaged nuclear power programme.

To carry out all the above mentioned analyses, the IAEA's set of methodologies for energy and nuclear power planning have been used. The specific models used are: (i) MAED for energy and electricity demand analysis and projection of electric load profiles, (ii) BALANCE for energy resources allocation to power and non-power sectors, (iii) ELECTRIC (WASP-III plus) for least-cost electric system expansion analysis, (iv) IMPACTS for environmental impact analysis, and (v) FINPLAN for financial analysis.

Energy and Electricity Demand Analysis Model

The Model for Analysis of the Energy Demand, MAED, is a simulation model designed to evaluate medium and long term demand for energy in a country or a region. The methodology comprises the following basic sequence of operation:

- Breakdown of the structure of the country's final energy consumption into a multitude of individual categories of end-use in a consistent manner;
- Identification of the social, economic and technical factors influencing each category of final energy demand;
- Specification (in mathematical terms) of the functional links between energy consumption and the factors governing that consumption;
- Reconstruction of the country's structure of final demand based on socioeconomic and technical data for the base year of the study (1992–93 financial year in the case of the present study);
- Construction of "scenarios of socioeconomic and technical development"; which consists of establishing possible future situations of the country under study with respect to the evolution of demographic, macroeconomic, socioeconomic and technical factors;
- Evaluation of the energy consumption corresponding to each scenario.

The main features of the MAED approach are different from that of time trends and econometric methods. The design of MAED was to overcome some of previous models' weaknesses such as the analysis based on price elasticity which is no longer satisfactory under the present world energy price fluctuations. The main features of MAED are to reflect:

- Structural changes affecting medium and long term energy demand by means of a detailed analysis of the social, economic and technical system. This approach takes into account, in particular, the changing social needs of individuals, for example, for cooking and other appliances in households, transportation and others; and the policies for national development including industrialization, and policies on transportation, housing, services and national security.

- Trends in the potential market for each final energy form: electricity, coal, gas, oil, solar energy, etc.

The MAED model consists of three modules. Module 1 is basically an updated version of the MEDEE-2 model developed for the International Institute for Applied Systems Analysis (IIASA) for analysis of the evolution of overall energy, including electricity, demand in a region or country [1,2]. Module 1 is used to determine the future demand for all forms of energy in all sectors of the economy.

The electricity demand projected with the help of Module 1 of the MAED model is in the form of annual electricity requirements at the user end. This demand has to be converted to hourly demand at the generation system level so that the requirements of the electricity generation system expansion could be planned. The distribution of electrical load over time, which characterizes the pattern of electricity usage, is crucial for selection of the generating units to be added and for their loading in the system. The ELECTRIC (WASP) module of ENPEP requires as input, projections of system peak demand and load duration curves. This information has been prepared in the present study with the help of modules 2 and 3 of MAED model. Module 2 uses annual electricity requirements in different sectors of the economy and converts them into hourly system load by taking into account system losses (auxiliary consumption, transmission losses and distribution losses), seasonal variation of electricity consumption in different sectors and hourly load pattern of demand in these sectors. Module 3 rearranges the hourly system load in decreasing order to work out the system peak demand and load duration curves.

By means of this feature, the results from MAED can be fed directly into the ELECTRIC module for further analysis of the least-cost expansion plan for the electricity generating system. Technically, MAED is organized as illustrated in Fig. 1.2.

Overall Energy Demand–Supply Balancing Model

For the analysis of energy resource allocation to power and non-power sectors, the BALANCE module of ENPEP has been used in conjunction with the ELECTRIC module. The BALANCE module integrates energy supply and demand activities for the purpose of providing information necessary for decision making. The supply/demand balance approach ensures that the amounts of fuels supplied and demanded are equal and that the quantities of fuels consumed are consistent with the costs of production/supply and the prices paid by consumers.

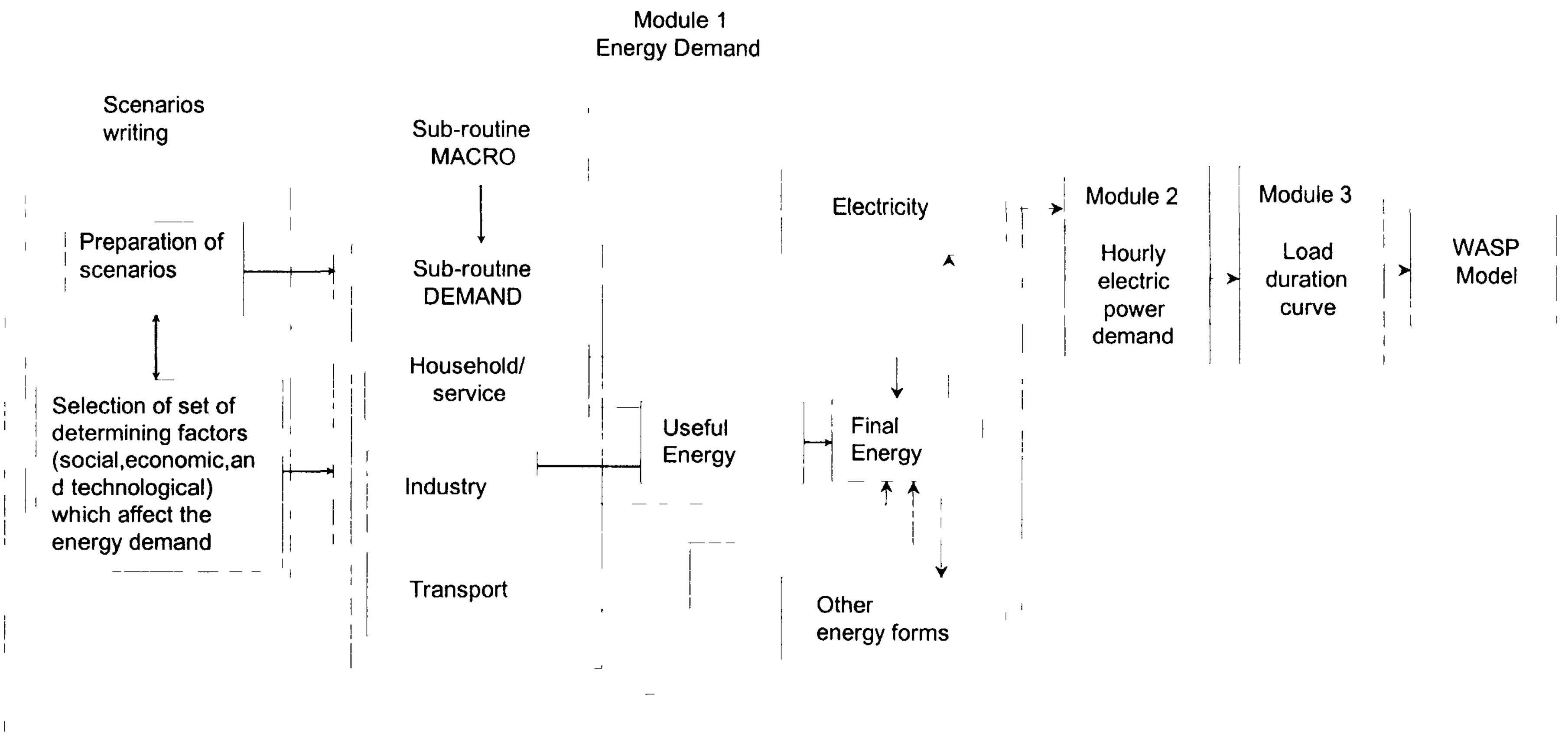


FIG. 1.2. Introduction between the MAED and WASP Methodologies for executing Energy/Nuclear Power Planning Studies

BALANCE uses a non-linear, equilibrium approach for determining the energy supply demand balance. In this formulation, an energy network is designed that traces the flow of energy from primary resources (e.g., crude oil, coal) through to final or useful energy demand. In a BALANCE analysis, energy demand is sensitive to the prices of supply alternatives and supply prices are sensitive to the quantities of different fuels demanded. In its operation, BALANCE simultaneously finds an equilibrium for all energy supply forms and all energy uses that are included in the network. The solution generated by BALANCE provides a consistent view of energy flow through the network for the set of assumptions and conditions that have been provided as input to the model. The solution is in "equilibrium" because the feedback effects of demand and supply adjusting to price differences are included in the analysis. The energy flows and prices developed in BALANCE can be passed to the IMPACTS module that evaluates the environmental impacts and resource requirements [3].

Electric System Expansion Optimization Model

The ELECTRIC module of ENPEP is based on the WASP-III Plus [4,5]. It determines the electricity generating system expansion plan that adequately meets demand for electric power at minimum cost while respecting user-specified constraints. ELECTRIC is directed to long term planning, beyond a 10 year time horizon, and is intended to address a number of critical issues in generation planning, including generating unit size, system reliability, details of the existing system, seasonal variation in loads and hydroelectric availability, and appropriate simulation of future system operation. It utilizes probabilistic simulation to estimate system production costs, unserved energy and reliability; and dynamic programming for optimization of system expansion policies. ELECTRIC is organized in a modular way which permits the user to monitor intermediate results, avoiding waste of valuable computer time due to possible input data errors.

ELECTRIC, permits finding the optimal expansion plan for a power generating system over a period of up to thirty years , within constraints specified by the planner. The information needed by the model includes the load forecast, characteristics of the power plants already in operation or firmly committed; characteristics of the power plants that can be used as alternatives for system expansion; the constraints to be considered in the analysis, such as the number of units of each candidate plant that can be added in a given year; reliability criteria, such as, the Loss-of-Load probability (LOLP) and minimum reserve margin to be satisfied by each expansion policy; investment and O&M costs of each plant type as well as other technical and economic parameters. The optimum solution is evaluated and reported in terms of minimum discounted total cost including investment, operation and energy-not-served costs. This solution displays the optimal expansion schedule of power plant addition to the power system selected from the list of expansion alternatives specified by the user.

In addition, ELECTRIC allows conducting sensitivity studies on different parameters such as fuel prices, discount and escalation rates, construction time, and energy-not-served cost. Such capability allows the planner to make comparisons of different plant descriptions of both the candidate and existing power plants within the optimized expansion system; and to explore alternative ways of power system expansion as dictated by new policies and constraints within the national development requirements. The overall organization of the ELECTRIC module is illustrated in Fig. 1.3.

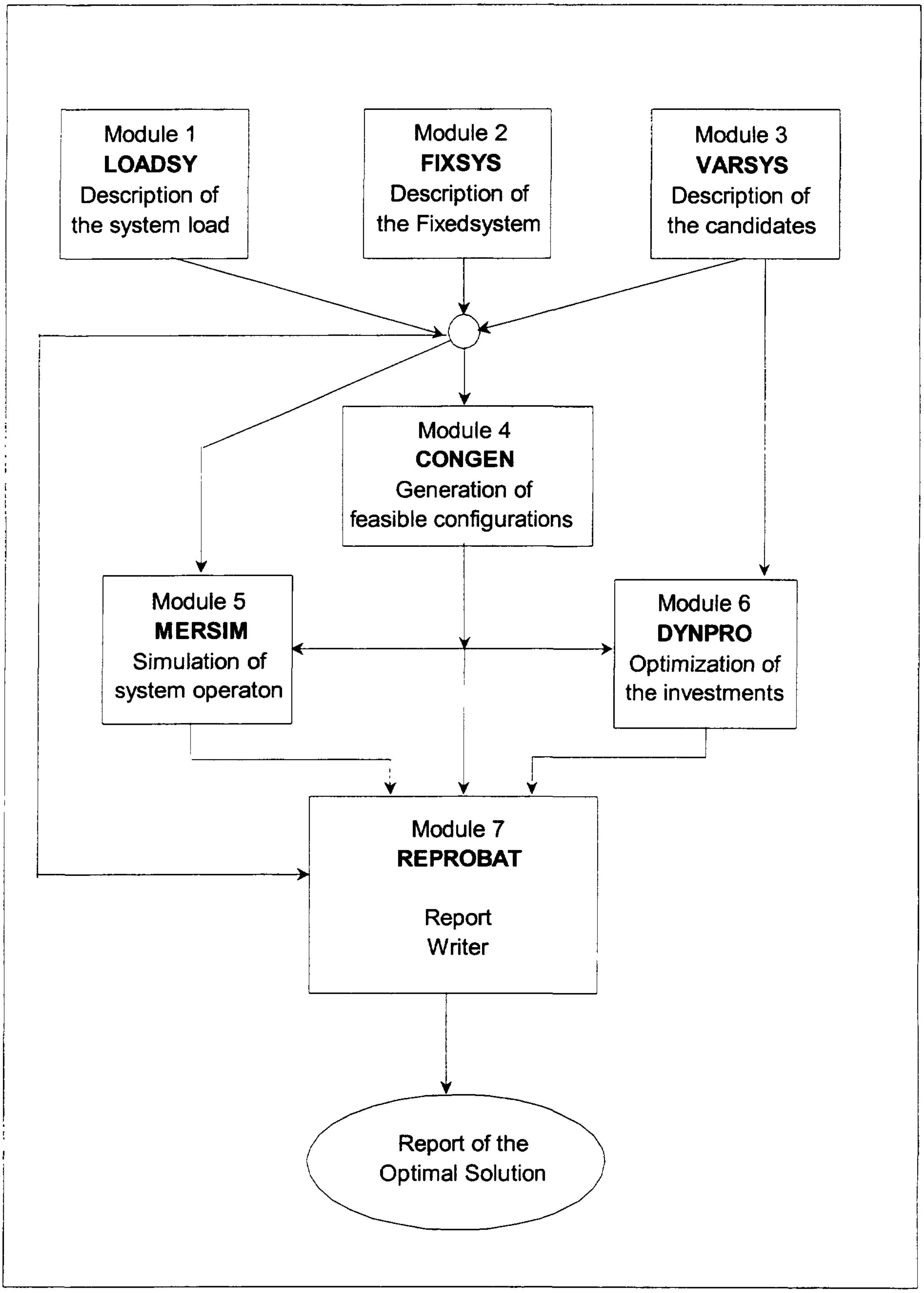


FIG. 1.3. Structure of ELECTRIC module of ENPEP

Environmental Assessment Model

For assessment of the environmental impacts of alternative plans for expansion of electricity generation system, IMPACTS module of ENPEP has been used in this study. Quite frequently, an energy system that is designed solely from energy supply perspective cannot be implemented because of environmental constraints or resource limitations. The IMPACTS module is designed to estimate these effects. Facilities from both energy supply systems and energy consuming systems can be included in an IMPACTS analysis. For example, coal mines, power plants, refineries and natural gas supply pipelines may be included as supply systems. Industrial boilers, residential space heaters, and automobiles may be included as demand facilities. IMPACTS will determine the environmental impacts of all these type of facilities. IMPACTS takes information from the ELECTRIC module on electricity generation by each type of plant and the corresponding quantities of fuels used. The data required for all other energy supply and use facilities are imported from the BALANCE module of ENPEP. The emission factors for various pollutants, worked out by the user based on fuel characteristics and technology, are used for evaluating the emissions of various pollutants from electricity generation. The module allows introduction of pollution control devices to different power plants to curtail emissions.

Financial Analysis Model

Financial analysis of the envisaged nuclear power development plan has been carried out with the help of the FINPLAN model. This model has specifically been designed to analyse financial viability of an investment programme of a power utility. It uses standard methodology for preparing yearly projected financial statements, viz. Balance Sheets, Income Statements, Cash Flow Statement, on the basis of information provided by the user on schedule of future investments, sources and terms of financing, inflation and escalation rates, projected revenues, etc. It also works out important financial ratios which are helpful for assessing financial viability of a proposed investment programme.

Integration of Various Models

Figure 1.4 shows the interaction of all the models used for the study. It can be noted that different models interact with one another and pass on relevant information which is used for further analysis. The models also provide feedback information which in certain cases necessitates revision of the analysis done with the previous model. For example, the environmental analysis or the financial analysis may require revision of electric system expansion plan worked out with the help of ELECTRIC Module. Likewise, overall energy demand–supply balance may require revision of allocation of primary energy sources to electricity generation. This iterative process integrates the entire energy system and ensures consistency.

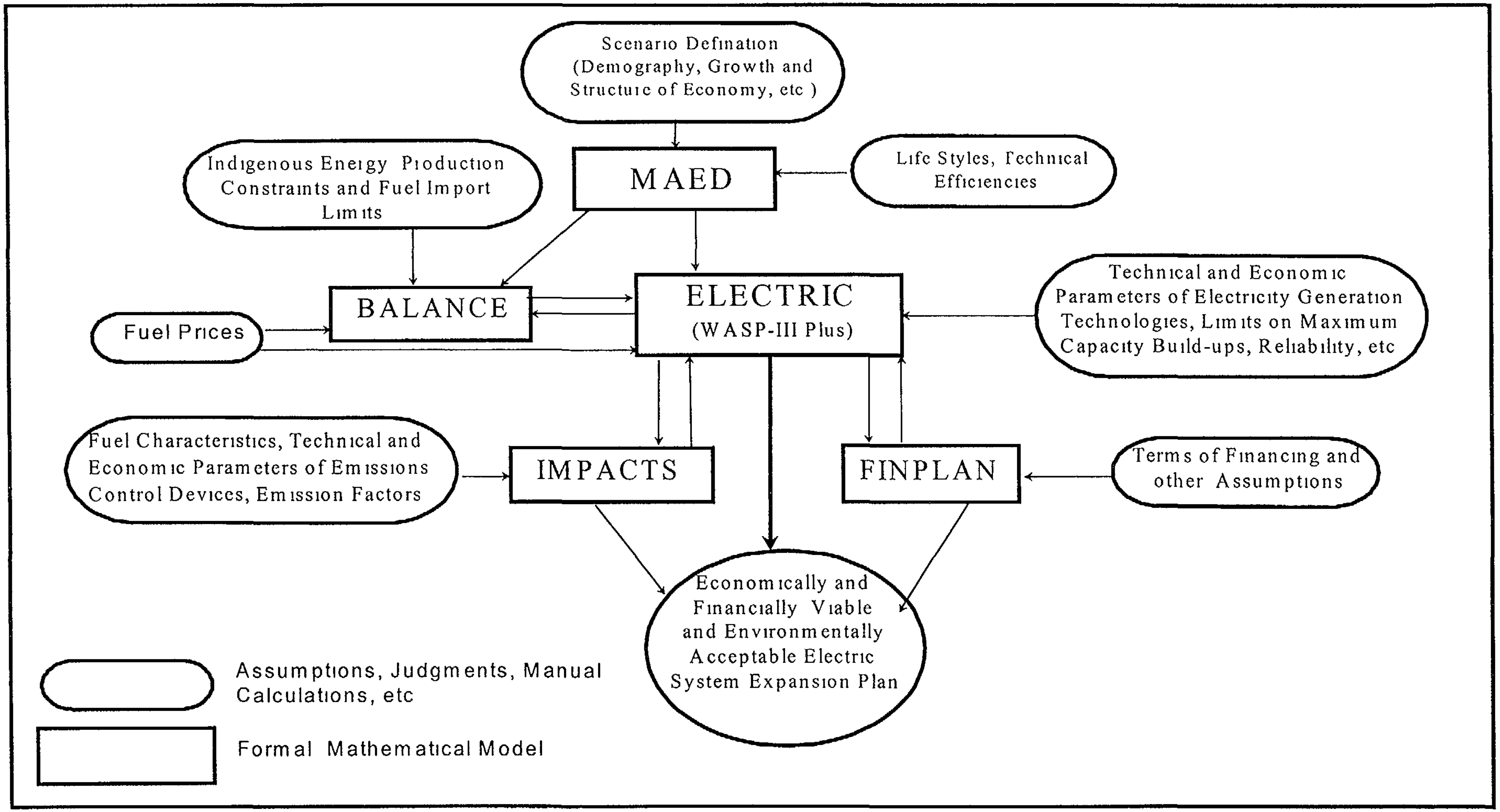


FIG 1 4 Schematic Diagram Showing Interaction

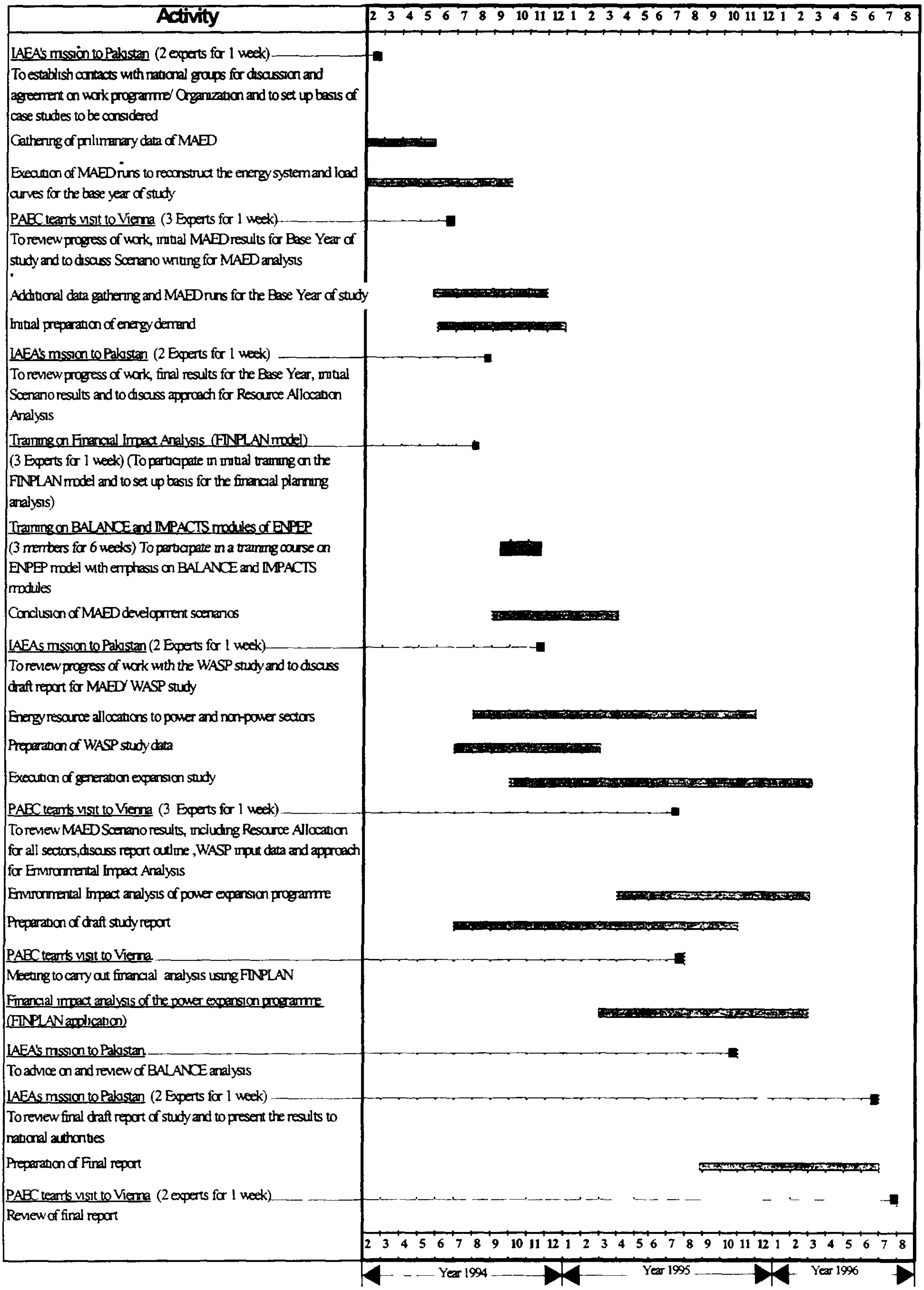


FIG 1 5 Schedule of Activities for Execution of Energy and Nuclear Power Planning Study for Pakistan

1.4. IAEA Support for the Study

The major tasks and activities for carrying out the study are shown in Fig. 1.5. The study was launched in February 1994 when an IAEA expert mission visited Pakistan to assist in finalising the work programme for the project. It was envisaged that about two years time would be required to carry out various activities identified for the study. During this period, the national team has been in constant touch with the IAEA's experts and has had regular meetings for review of the progress of the study. All the analytical tools mentioned above were transferred by the IAEA to PAEC. In addition, several members of the national team were provided formal as well as on-the-job training by the Agency in the use of these models. Besides a number of technical meetings of the IAEA experts and the national team were arranged in Vienna and Islamabad for review of the work and for providing technical guidance for the study. A total of 2.75 man-months of Expert Services, 2.75 man-months of national teams visits to IAEA and 5.25 man-months of training of the members of national team were arranged by the IAEA for this project. This technical support from IAEA helped the national team a great deal to develop capability for undertaking such a comprehensive study and enabled it to successfully complete the study within the stipulated time.

1.5. Organization of Study Report

The report consists of 10 chapters. After this introductory chapter, the 2nd chapter describes the Energy-Economy Setting in the country. It reviews historical evolution of demography, economy and energy supplies and consumption. Chapter 3 explains the major elements of different scenarios constructed for the study. Chapter 4 describes the future evolution of energy and electricity demand worked out under different scenarios. Chapter 5 gives the projections of electricity demand and the peak power demand. Chapter 6 focuses on the issue of energy resources allocation to power and non-power sectors. Chapter 7 describes the formulation of alternative plans for expansion of electricity generation system. Chapter 8 is devoted to assessment of environmental impacts of alternative expansion plans for the power sector. Chapter 9 details the financial analysis of the envisaged nuclear power development plan. And finally, Chapter 10 summarises the main conclusions and recommendations resulting from all the analysis.

Chapter 2

GENERAL ENERGY-ECONOMY SETTING

2.1. General Background

2.1.1. Geography and Climate

Pakistan is located in the north-western part of the South Asian sub-continent and lies between 23° and 37° north latitudes and 60° and 76° east longitudes. It is bounded in the North and north-west by Afghanistan, in the north-east by China, in the east and south-East by India, in the south by the Arabian sea and in the west by The Islamic Republic of Iran.

The country is a land of diversified physical features, and six major physical regions can be identified as:

1. Northern Mountains i.e. the Karakorum, Himalayas and the Hindukash mountain ranges, which contain some of the highest peaks of the world, e.g. Karakorum-2, well known as K-2 (8616 meters), is the second highest peak in the world, Nanga Parbat (8215 meters) is a prominent peak of the Himalayas and Tirich Mir (7736 meters) is the highest peak of the Hindukash;
2. The Western off-shoots of the Himalayas such as Sulaiman range lying in the west of the country;
3. Baluchistan Plateau;
4. Potowar Plateau and the Salt Range;
5. Upper and Lower Indus Plains, which comprise about one fifth of the total land area of the country and represent the main agricultural region of the country; and
6. The Thar desert which lies in the south-east of Lower Indus plains where the largest identified coal resources of the country exist [6].

The total area of Pakistan is 796 thousand km^2. Out of this about 0.207 million km^2 are cultivated, while another 0.093 million km^2 are culturable waste (land area that can be brought under cultivation with some investment). Pakistan suffers from scant forest resources. The forest area of about 0.035 million km^2 [7] is quite inadequate to meet the growing demand for timber and wood, and to conserve and protect the environment. In view of the growing concern about environmental degradation, the Government of Pakistan has set a target of increasing the forest area to a level of 10% in the next 15 years [8]. The current Five Year Plan accords high priority to the development of forestry and range lands, and watershed management, as well as, promotion of forestry on private lands.

Similar to the diversity in physical features, Pakistan has great diversity of climate. In the northern mountains and western off-shoots of the Himalayas the winters are extremely cold and mountains remain snow covered, while the summer temperatures reach up to 52°C at some places in the Baluchistan Plateau and the Lower Indus Plains.

Rainfall at most of the places in Pakistan is scanty. Nearly three fourths of Pakistan receives average annual rainfall of less than 25 cm [6]. Pakistan is on the margin of the monsoon climate and most of the rainfall is in the months of July, August and September.

Within the Indus Basin, flooding is an annual occurrence, and some parts of the Sind province are dependent on flood irrigated agriculture.

2.1.2. Demography

Pakistan is a very populous country with 124.45 million inhabitants, estimated as of January 1994. It ranks 8th in the world in terms of population [8]. The population density of the country is about 156 persons/km^2 which is rather low compared to the density in some other developing countries such as India (269 persons/km^2). This is mainly due to the fact that the largest province in terms of area, Baluchistan, is sparsely populated.

The population census has been carried out in Pakistan at a regular interval in the past, i.e. 1951, 1961, 1972 and 1981. However, the census due in 1991 has not been conducted so far. Based on various population growth surveys conducted by Pakistan Statistical Bureau, the present average annual growth rate of population is 3% as compared to a growth rate of 3.55% p.a. during 1960s and 3.1% p.a. during 1980s. Column 3 in Table 2.1 reports the historic trend of population growth since 1951. The reduction in the pace of population growth in the last two decades has been possible due to the family planning programmes introduced by the Government. In recent years, efforts in this direction have been intensified, and it is expected that the population growth will further decrease. The major component of the social welfare programme, being pursued in the current Five Year Plan, are: (i) provision of family planning Services at the door steps, (ii) use of mass media to provide awareness on family planning methods, (iii) conducting of research studies on population planning methods and their comparative advantages, and (iv) setting up of institutional framework for increased involvement of Non Government Organizations (NGOs) in the advocacy and management of family planning services [10]. As a result, it is envisaged that the population growth rate will decline to 2.8% p.a. during 1993–1998.

Table 2.1 also reports the population of urban and rural areas. In the population statistics, these two regions are defined on administrative basis. Before, the 1981 census, the urban areas were defined as "All municipalities, Civil lines, areas which have been declared to be Corporations, Municipal committees, Town Committees by the provincial Government and Cantonments". All these areas have distinctly urban characteristics such as running water and sanitation systems, and most of them have population more than 5,000 persons [11]. Since the 1981 census, all areas with urban characteristics are included in the urban region irrespective of their population.

Table 2.1. Population of Pakistan (1951–1994)

Year	Total Population (Million)	Annual Growth Rate (% p.a)	No of dwellings (Million)	No. of Persons per Household	Urban Population (Million)	Annual Growth Rate (% p.a.)	Share (%)	Rural Population (Million)	Annual Growth Rate (% p.a.)	Share (%)
1950–51	33 82				6 02		17 80	27 80		82 20
1960–61	42 98	2 43			9 65	4 84	22 46	33 32	1 83	77 53
1972–73	65 32	3 55	10 88	5 4	16 59	4 62	25 40	48 73	3 22	74 60
1980–81	84 25	3 23	12 59	6 7	23 84	4 63	28 30	60 41	2 72	71 71
1990–91	113 78	3 05			35 84	4 16	31 50	77 94	2 58	68 50
1992–93	120 83	3 05	16 81	7 19	38 06	3 05	31 50	82 77	3 05	68 50

Source. [9, 10 & 11]

In 1992–93 only 31.5% of the population was residing in the urban region. Thus, the vast majority of population in the country (i.e. about 69%) still lives without basic urban facilities. Table 2.1 shows the historical trend of urban population, its growth rates and share in the total population in Pakistan since 1951. Starting from only 6 million inhabitants in 1951, the population in the urban region has witnessed about six fold increase during the last 43 years. However, the share of urban population in the total population has been increasing slowly as it reached the level of about 32% in 1993 compared to about 18% in 1951 (i.e. less than two fold increase).

There have been a significant difference between the population growth rates in the two regions. In the last three decades, the population growth rates in urban areas have been much higher than the growth rates in rural areas. This difference is partly due to inter-region migration. As the economy is moving towards more industrialization; with concentration of industries in the big cities, and mechanization of the agriculture sector, better job opportunities in the urban region induce migration from the rural to urban region. This is putting a burden on the existing civic facilities in the urban areas and enlargement of urban slums. To overcome this problem, the Government of Pakistan is pursuing policies to encourage establishment of industries in the remote areas and development of infrastructure in these regions.

Table 2.2 reports the labour force statistics of Pakistan in the two regions and on the aggregate. The labour force participation rates have been quite low in Pakistan. According to the labour surveys, of the 121 million persons, only about 34 million persons (around 28%) were in the labour force in 1992–93. The major reason behind this has been the big share of the non-working age population. For example, in 1969–70, the share of non-working age population was about 47% which declined to about 34% in 1992–93. Another reason is low female participation rate in the labour force. Although, females in the rural areas participate in the family business, especially farming and related activities, their participation has not been recognized fully in these statistics and there is an under reporting of female workers of rural zones in the labour force. Contrary to this, the female participation rate in urban areas is low due to social norms and lack of institutional facilities for the working mothers.

Table 2.2 also shows that the unemployment rate in Pakistan was quite low, i.e. about 2% in 1969–70, but it has been increasing over time and reached the level of 4.74% in 1992–93. The detailed data show that the unemployment rate went up to a level of 6.28% in the period 1990–91, and that there has been improvement in employment level in the recent years. At the regional levels, the unemployment rates in the urban population have been higher than that in the rural population. This trend is similar to that in most of the developing countries indicating two phenomena: (i) rural labour migration to the urban areas for better job search and (ii) disguised unemployment in the rural areas. One of the main goals of the current development policy is harnessing of the large stock of human capital of the country. In this regard, efforts have been made in three directions. Firstly, policies have been made to expand the overall economic activities in such a way that the job opportunities expand. Secondly, specific employment generating schemes are being implemented. Thirdly, technical and vocational training schemes are being launched to improve the labour skill and quality of labour services.

Table 2.2. Labour Force in Pakistan

	1969–70	1986–87	1989–90	1992–93
Total Population (Million)	59.70	100.70	110.36	120.83
Rural	44.97	72.20	77.71	82.77
Urban	14.73	28.50	32.66	38.06
Working Age Population (Million)	32.16	67.37	73.61	79.23
Rural	24.10	47.36	51.04	53.34
Urban	8.06	20.01	22.57	26.20
Potential Labour Force (Million)	18.11	29.60	31.82	33.57
Rural	12.60	22.24	23.23	23.65
Urban	5.51	7.36	8.59	9.92
Unemployment Rate (%)	1.99	3.05	3.13	4.74
Rural	1.83	2.50	2.60	4.29
Urban	2.36	4.51	4.58	5.88
Labour Force Participation Rate (1) (%)	30.34	29.40	28.83	27.87
Rural	31.40	30.81	29.90	28.77
Urban	27.27	26.26	26.28	25.83

(1) Share of potential labour force in total population
Source: [10]

Table 2.3. Sectoral Share in Labour Force (%)

Year	Agriculture	Mining	Manufacturing	Construction	Electricity and Gas	Trade	Transport	Others
1966–67	53.4	0.2	16.3	3.8	0.4	11.3	5.1	9.6
1971–72	57.3	0.5	12.5	3.4	0.4	9.9	4.8	11.3
1974–75	54.8	0.2	13.6	4.2	0.5	11.1	4.9	10.8
1978–79	52.7	0.1	14.5	4.9	0.7	11.1	4.7	11.2
1985–86	54.0	0.3	13.1	5.2	0.5	11.4	4.4	11.0
1990–91	47.5	0.2	12.2	6.6	0.8	13.2	5.2	14.2
1991–92	48.3	0.3	12.3	6.3	0.8	13.1	5.5	13.5

Source: [11]

The structure of the economy have changed over time and as a result the relative shares of employed labour force in the major economic sectors have also changed. Labour employment pattern by major economic sectors reveals that the Agriculture sector has been the biggest employer (see Table 2.3). The sector accounted for more than 50% share in the total employment till mid 1980s. Since then, though, the share of the Agriculture sector has been declining, the sector still employ 48% of the total labour force. As shown in Table 2.3, the share of the Manufacturing sector in laur employment has been declining since the late

1960s, however, these figures do not include labour employment in the small-scale and cottage industries for which reliable data are not available.

The shares of the Agriculture, Manufacturing and the Mining sectors together in the working labour force declined from 70% in 1967 to 61% in 1992. This shows that in the labour employment, the Service sector has been providing more opportunities than the commodity producing sectors.

2.2. Macroeconomic Background

During the last 30 years (1963–1993) Pakistan's economy has grown at an average annual growth rate of 5.7%. However, due to high population growth rate, the per capita GDP has increased at only 2.6% p.a. during the same period. The present per capita income in Pakistan is Rs. 14 650 (US $476[1]), which places the country among the low income developing economies of the world.

Pakistan has a mixed economy where the Government plays an important role along with the private sector in the economic development of the country. To accelerate the pace of economic development, the Government formulates Five Year economic development plans which are implemented through the annual development programmes. Up till now 6 Five Year development plans have been implemented since 1960, while 1971 to 1978 was the period when development plans were formulated only on annual basis. Table 2.4 reports the sectoral growth rates of the economy for the period 1960–1961 to 1992–1993. It may be noted that among the major sectors Manufacturing and Construction stand out as the fast growing sectors; their GDP growth rates have been in the range of 5% to 12% per annum. Although, the Energy sector has been growing quite rapidly, its share in the total GDP is very small. The lowest growth has been experienced in the Agriculture sector which registered the growth rates between 3.4% to 5.5% per annum.

Table 2.4. Growth Rates of Gross Domestic Product at Constant Factor Cost of 1992–1993

(% p.a)

	1961-1966	1966–1971	1971–1978	1978–83	1983–88	1988–1993
Agriculture	3.90	5.52	3.39	4.49	3.48	3.69
Mining	10.43	3.24	6.33	8.09	11.75	5.42
Manufacturing	10.57	7.56	6.14	9.87	8.21	5.94
Building and Cons.	12.01	5.20	10.09	4.68	6.82	4.56
Energy	14.75	30.34	10.92	8.15	10.76	10.95
Services	8.77	3.98	9.39	7.06	6.74	4.90
Total GDP	7.06	5.28	6.82	6.55	6.16	4.92

Source: Based on [10]

The structure of Pakistan's economy has undergone significant changes during the past decades. Table 2.5 shows the sectoral shares of GDP since 1961. The share of the Agriculture sector in GDP has declined from 45% in 1961 to 25% in 1993, while the share of the Manufacturing sector has increased from 10% to 17% in the corresponding years. The Service

[1]Estimated figure of 1994-1995 [10].

sector has grown at somewhat higher rate compared to the total economy during 1960–1993 with the result that its share has increased from 42% to 50%. The other sectors (Construction, Mining and Energy) have small contribution in the total GDP.

Table 2.5. Sectoral Shares of Gross Domestic Product

Year	1960-61	1970–71	1977–78	1982–83	1987–88	1992–93
Agriculture (%)	44.57	38.80	32.96	29.90	26.31	24.81
Mining (%)	0.42	0.44	0.43	0.47	0.60	0.62
Manufacturing (%)	10.14	13.26	12.84	14.97	16.48	17.29
Building and Construction.(%)	3.08	3.84	4.4	4.09	4.22	4.15
Energy (%)	0.37	1.52	1.83	1.98	2.44	3.23
Services (%)	41.42	42.13	47.45	48.59	49.94	49.90
Total GDP[a] (Million Rs.)	201 576	366 741	509 952	700 332	944 192	1 200 455
Population (Million)	46.2	61.49	76.60	89.12	103.82	120.83
GDP/Capita (Rs./Capita)	4363	5964	6657	7858	9095	9935

(a) at Constant Factor Cost of 1992–93
Source: Based on [10]

Although, the Agriculture sector share in GDP has declined considerably, Pakistan is basically an agricultural economy, with around 69% of the population living in the rural areas and with about 48% of the labour force engaged in farming and related activities. The vast plains of the country are among the world's largest irrigated farmlands. The major crops of the country are wheat, rice, cotton and sugarcane. The share of wheat and rice in total farm production is 44% and 16% respectively, while from the cash crops category the contribution of cotton is 23% and that of sugarcane is 14%. The total cropped area in the country is 27% of the country's total area and is estimated at 21.7 million hectares. Over the last 3 decades, there has been significant improvement in the application of modern inputs such as chemical fertilizer, improved seed and farm equipment. Table 2.6 reports the historical trends in the application of these farm inputs in Pakistan. Especially, there has been tremendous increase in the use of chemical fertilizer which increased from 2.1 nutrient tonnes per thousand hectare of cropped land in 1960 to about 98.9 nutrient tonnes per thousand hectare in 1993. Similarly, there has been improvement in the availability of tractors which increased from 0.33 per thousand hectare in 1970 to about 16 tractors per thousand hectare in 1993. Among other inputs, there has not been much improvement in the intensity of improved seed application, while there has been a marginal improvement in the water availability at the farm gate. With application of new production technologies, the productivity of the agriculture sector, i.e. yield per hectare, has improved for the major crops. In 1994–95, the yield in Pakistan of wheat, rice and sugarcane were 2049 kg, 1580 kg, 45 243 kg, respectively. However, these yields are still low compared to those in the advanced countries.

Similar to all other developing countries, Pakistan has been pursuing development policies to boost the manufacturing activities in the country and thus shifting the emphasis from the agriculture sector, i.e. primary goods production, to the Manufacturing sector. However, since it is an agricultural economy, most industries in Pakistan are agro based; primarily involved in processing of agricultural goods. As shown in Table 2.7, the major industries of Pakistan, in terms of value added, are Food and textile, while industries such as Iron and steel and capital goods have minor shares in the total value added of the Manufacturing sector.

Table 2.6. Basic Data on the Agriculture Sector of Pakistan

Year	Cropped Area (Million Hectares)	Fertilizer off-take ($NT/10^3$ Hectares)	Tractors (No. $/10^3$ Hectares)	Improved Seed Distribution ($Tonnes/10^3$ Hectares)	Water Availability (m^3/Hectares)
1960–61	14.86	2.11	na	na	na
1965–66	15.54	4.55	na	na	5059.68
1970–71	16.62	17.04	0.33	na	5181.60
1975–76	18.02	34.37	1.20	2.40	5882.64
1980–81	19.33	55.85	4.11	3.80	6248.40
1985–86	20.28	74.54	8.93	3.07	6370.32
1990–91	21.89	86.47	12.31	3.80	6736.08
1991–92	21.72	86.74	13.88	3.04	6918.96
1992–93	21.72	98.90	15.54	2.94	7071.36

Note: NT: nutrient tonnes. na: not available
Source: [10]

Since 1960, the economy went through three eras of significant policy changes. In the mid 1960s (2nd Five Year Plan period), vigorous development plan and policies were followed to establish a strong manufacturing sector in Pakistan along with the increase in productivity of the agriculture sector. In this period, liberal concessions were given to the private sector, in terms of soft loans and cheap foreign currency, for the industrialization of the economy. As a result, large investments were made by the public and private sectors in the Manufacturing sector and the economy witnessed an impressive economic growth rate. But this created a problem of income distribution. In order to correct this problem, the Government adopted a policy of nationalization of industries and financial institutions in the early 1970s. Massive investments were made by the public sector in the basic industries such as steel mill, fertilizer and cement industries. However, this trend could not be continued for a long period. Since the late 1970s, Pakistan has been persistently following the policies of de-regulation, privatization and liberalization of the economy. This encompasses institutional reforms in the industrial and financial sector, dis-investment programme of the industrial units in the public sector, grant of fiscal and monetary concessions to foreign investors to bring them at par with their local counterparts, and induction of the private sector in the power generation and distribution which has been traditionally in the public sector. The private sector is being encouraged to enter almost all spheres of the economy e.g. banking, air transportation, telecommunications, electricity generation and distribution, higher education etc. The response to these policies have been quite encouraging as the foreign private investment exhibited remarkable increase in the recent years. During 1994–95, foreign investment rose to 1418 million dollars from 551 million dollars in 1993–94. A recent study [12] shows that the emerging markets in the developing countries will witness an inflow of 50 billion dollars of foreign investment. If Pakistan continues to pursue these policies successfully, it is expected to claim a bigger portion of this direct investment.

Table 2.7. Value Added by Major Industries (Million Rs.)

	1984–85	Share (%)	1990–91	Share (%)
Basic Material Industries				
Paper & Products, Printing & Publishing	1099		4258	
Drugs & Ph., Industrial & Other Chemicals, Petroleum Refining, Petroleum & Coal, Rubber & Plastic Products	10 097		21 666	
Non-Metallic Mineral Products	3559		8416	
Iron & Steel Basic Industries	5441		6146	
Total	20 196	39.16	40 486	36.47
Machinery and Equipment Industries				
Fabricated Metal Products	523		956	
Non-Electrical Goods	1269		2801	
Electrical Machinery	1558		4561	
Transport Equipment	1324		2875	
Measuring, Photographic, Optical Goods	121		262	
Others	124		194	
Total	4919	9.54	11 649	10.49
Consumer Goods Industries				
Food, Beverages, Tobacco	16 332		24 218	
Textiles, Wearing Apparels, Leather & Products	9087		32 480	
Ginning, Pressing & Bailing, Wood & Products, Furniture & Fixture	980		1762	
Sports & Athletic Goods	57		421	
Total	26 456	51.30	58 881	53.04
Grand Total	51 571	100.00	111 016	100.00

Source: [10]

In view of these market oriented policies and the awareness that Government will be able to invest more for human resource development, it is expected that Pakistan's economy will grow at a rate (i.e. 7% p.a.) higher than that in the past.

With the structural changes in the economy, the composition of exports and imports has been changing. Table 2.8 shows the total exports of Pakistan and its composition. The economic classification of exports reveals that most export earnings now accrue from the export of manufactured goods. Initially, in the period 1969–70, these goods had only a 44% share in export earnings compared to the 33% share of primary goods and 23% share of semi-manufactured goods. Over time the share of manufactured goods has increased. Since 1990, there has been a significant increase in the share of these goods in the total export earnings. However, all these commodities are still agro based and only their level of processing has been increased.

The imports of Pakistan, in value terms, have been growing at the rate of 11% per annum between 1969–1994. Over time, there has been wide variation in the composition of the import bill (see Table 2.9). Till the mid 1980s, the share of capital goods was declining, while that of industrial raw material was increasing. This trend reversed in the late 1980s, when the share of capital goods started increasing. In 1993–94, industrial raw-material has the biggest share in the import bill. The big share of raw materials indicates the higher activity level of processing industries. Among the industrial raw materials crude oil and petroleum products are the major import products. Pakistan has been importing consumer goods including edible oil and wheat which account for about 10–23% of its import bill.

Table 2.8. Economic Classification of Exports

(US $ Million)

Year	Total Value	Shares in total exports (%)		
		Primary Commodities	Semi-Manufactures	Manufactured Goods
1969–70	338	33	23	44
1974–75	1039	48	13	39
1979–80	2365	42	15	43
1984–85	2491	29	17	54
1989–90	4954	20	24	56
1990–91	6131	19	24	57
1992–93	6813	15	21	64
1993–94	6803	10	24	66

Source: [10]

Pakistan has been following a trade liberalization policy for integrating its economy into the global trading system since the mid 1980s. Some recent developments in this regard are merging of all the para tariff in the statutory tariff regime, reduction in the maximum tariff rate from 92% to 70% and removal of quantitative restrictions, except in few cases. The emphasis of the trade policy is on diversity and expansion of exports and reduction in imports by creating efficient and import-competing industries. For example, the export oriented industries have been allowed concessional tariff treatment on the import of raw material and machinery, while imports of several commodities have been made freely importable to induce the local industries to become competitive. The world exports from 1987 to 1992 increased at an annual average rate of 9.26% and during this period the share of Pakistan's exports in the world exports rose from 0.16% to 0.20%. Efforts are being made to increase this share considerably in the future.

Pakistan has been having a negative trade balance for several decades, a part of which is offset by remittances from Pakistanis working abroad. To improve the balance of trade, apart from other measures, Pakistan opted the flexible exchange rate policy started from January 1982. In 1992–93 the average exchange rate was Rs. 25.96 per US dollar [13]. During January 1982 to 1992–93, the Rupee has been depreciating at the rate of about 10% p.a. against the US dollar.

Table 2.9. Economic Classification of Imports

Year	Total Value (US $ Million)	Shares in total imports (%)			
		Capital Goods	Raw material for Capital Goods	Raw material for Consumer Goods	Consumer Goods
1969–70	690	50	11	29	10
1974–75	2114	29	9	40	23
1979–80	4740	36	6	42	16
1984–85	5906	32	6	46	16
1989–90	6935	33	7	41	19
1990–91	7619	33	7	44	16
1992–93	9941	42	6	38	14
1993–94	8564	39	6	41	14

Source: [10]

2.3. Pattern of Energy Consumption and Supplies

2.3.1. Energy Demand

The total primary energy consumption in Pakistan in the year 1993 amounted to 55 million tons of oil equivalents (TOE) comprising some 61% in the form of commercial fuels and 38% as non-commercial fuels [14, 15]. The primary commercial energy consumption in the same year was equal to 33.6 million TOE (Oil: 39.2%, Gas 36.9%, Hydro 15.0%, Coal 8.4% and Nuclear: 0.4%), while the consumption of non-commercial fuels (wood, dung and crop residues) amounted to some 21.4 million TOE with the share of wood being more than 50%. The non-commercial fuels are used mainly as cooking fuels by the rural population and urban poor.

The demand for final commercial energy in Pakistan has been increasing rapidly as a result of developments in industry and transportation, mechanization of agriculture, improvements in social services, rural electrification and substitution of non-commercial fuels by commercial fuels in the households. It increased from 1.4 million TOE in 1951 to 33.6 million TOE in 1993, i.e. by a factor of 24 during the last 43 years. During the same period the demand for electricity increased even faster, from 0.26 to 48.8 billion kW·h i.e. by a factor of about 188. The corresponding improvements in the per capita levels of commercial energy and electricity consumption are by factors of 7 and 58 respectively (see Table 2.10).

The composition of final energy consumption by sector and by fuel in 1993 is shown in Table 2.11. It may be noted that the Manufacturing sector is the largest consumer of commercial energy accounting for a share of 40.7% in the total commercial energy demand. The shares of other sectors are; Transport: 24.3%, Residential: 16.8%, Agriculture: 10.9%, Service: 4.6%, Construction: 0.5% and Mining: 0.3%. Energy demand by fuel type shows that petroleum products and gas are the two major contributors which meet about 74% of the final energy demand, while contributions of electricity and coal are 15% and 11% respectively.

Table 2.10. Consumption of Primary Commercial Energy and Electricity in Pakistan

Year	Total		Per Capita	
	Energy (10^6 TOE)	Electricity (10^9 kW·h)	Energy (TOE)	Electricity (kW·h)
1950–51	1.4	0.3	0.04	7
1960–61	3.1	1.3	0.07	28
1970–71	7.7	7.2	0.13	117
1980–81	15.2	16.1	0.18	192
1990–91	29.5	41.0	0.26	361
1992–93	33.6	48.8	0.28	404
1950–1993 increase	24	188	7	58

Source: [14 & 16]

Table 2.11. Final Energy Consumption in 1992–93

(Thousand TOE)

Sector	Oil Products	LPG	Gas	Coal	Electricity	Total Commercial	Total non-Commercial
Agriculture	1749				459	2208	
Construction	90				1	91	
Mining	53		1		2	55	
Manufacturing	1397		3606	2159	1051	8213	2079
Transport	4860	22	1	1	12**	4895	
Misc. Transport	390					390	
Domestic	454*	87	1773	1	1073	3388	18 231
Services	188	36	335		376	936	
Total	9182	145	5716	2161	2972	20 176	20 310

Non-Energy Uses (thousand TOE)

(i)	Fertilizer Feed Stocks (Gas):	1377
(ii)	Coke:	654
(iii)	Oil:	417
(iv)	Total Non- Energy:	2448
(v)	Bunkers:	176

Source: Based on [14]

The structure of energy demand has changed considerably over the past two decades. Figure 2.1 compares the sectoral composition of energy demands in 1972–73 and 1992–93. The Manufacturing and Transport sectors have been the major users of energy in these years but the share of Manufacturing sector has declined by about 6 percentage point over the last

20 year period, while the shares of the Residential and Agriculture sectors have increased by 9 and 3 percentage points respectively. Energy demands in these sectors have been growing at 11% and 8% per annum, respectively.

Figure 2.2 illustrates the changes in fuel composition of the final energy demands in the period from 1973 to 1993. The most significant change is in the share of electricity. There has been about 6 percentage point increase in the share of electricity in total final energy consumption during this period. Petroleum products remained the major contributor in the final energy demand, however, their share has declined by about 4 percentage points.

In brief, the energy demand for the Residential sector has been growing most rapidly, and among all commercial energy products electricity demand has been rising at the fastest rate. Table 2.12 reports the historical trend of per capita consumption of energy and electricity from 1981 to 1993. It shows that, there has been 110% increase in electricity use compared to 54% increase in primary energy consumption and 38% increase in GDP.

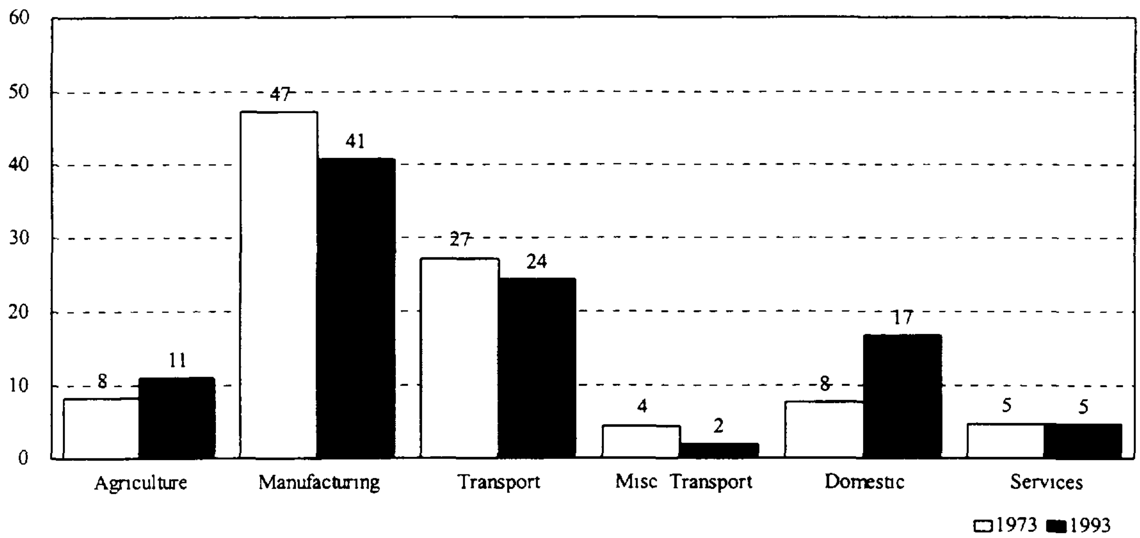


FIG. 2.1. Comparison of Final Energy Consumption in the Major Sectors of the Economy (%Share in total energy demand)

Source: [14, 16]

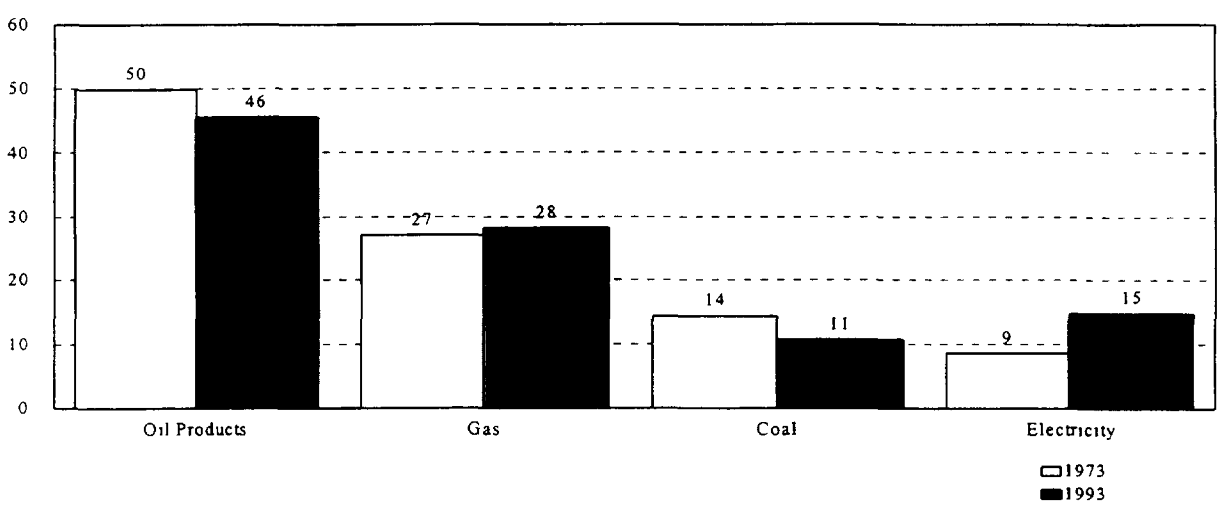


FIG. 2.2. Comparison of the Shares of Fuel Types in Total Energy Demand (%Share)
Source: [14, 16]

Table 2.12. Macroeconomic and Energy Indicators of Pakistan

Year	Per Capita Gross Domestic Product[(a)]		Per Capita Primary Energy Consumption		Per Capita Electricity Consumption		Energy Intensity			
							Primary Energy		Electricity	
	Rs	1980= 100	TOE	1980= 100	kW h	1980= 100	TOE/ 10^6 Rs	1980= 100	kW h/ 10^3 Rs	1980= 100
1980–81	2956 00	100 00	0 18	100 00	191 58	100 00	61 41	100 00	64 81	100 00
1981–82	3083 88	104 33	0 19	105 56	204 63	106 81	61 54	100 22	66 35	102 38
1982–83	3194 20	108 06	0 20	111 11	221 02	115 37	63 35	103 17	69 19	106 76
1983–84	3221 34	108 98	0 21	116 67	238 06	124 26	64 82	105 55	73 90	114 03
1984–85	3396 51	114 90	0 21	116 67	242 83	126 75	63 02	102 62	71 49	110 31
1985–86	3503 88	118 53	0 22	122 22	261 99	136 76	63 32	103 12	74 77	115 37
1986–87	3606 22	122 00	0 23	127 78	285 03	148 78	64 14	104 45	79 05	121 97
1987–88	3712 35	125 59	0 24	133 33	318 73	166 37	66 03	107 54	85 86	132 48
1988–89	3773 80	127 67	0 25	138 89	322 89	168 54	64 91	105 71	85 56	132 02
1989–90	3828 23	129 51	0 26	144 44	341 25	178 12	68 26	111 17	89 14	137 54
1990–91	3919 89	132 61	0 26	144 44	360 71	188 28	66 19	107 80	92 02	141 99
1991–92	4095 25	138 54	0 27	148 81	387 35	202 27	65 41	106 51	94 59	145 94
1992–93	4066 25	137 56	0 28	154 48	403 46	210 68	68 38	111 36	99 22	153 10

Note [(a)] At Constant Factor Cost of 1980–81

Source [10 & 14]

Table 2 12 also shows energy and electricity intensities, i.e units of energy, electricity used per unit of value added. There has been a steady increase in electricity intensity which registered about 53% increase in the 13 year period (1980–1993) Contrary to this, there has been a small variation in primary energy intensity values which has been fluctuating in the range of 61 4 to 68 3 TOE/10^6Rs of GDP during this period

The past experience shows that the commercial energy consumption in Pakistan has been growing at a higher rate compared with the growth rate of GDP, resulting in income elasticity of greater than one, whereas the growth rate in non-commercial energy consumption is much slower than GDP It is expected that during the period 1993–1998, commercial energy demand will increase with a growth rate of 7.3% per annum against the GDP growth rate of 7% whereas the demand of non-commercial fuels will increase by 1 6% per annum [8] That is non-commercial fuels will be replaced by commercial

2.3.2. Structure of Energy Supply System

The pattern of commercial energy supply in Pakistan has undergone considerable changes during the last four decades. The shares of different energy sources (coal, oil, gas, hydro and nuclear) in the primary energy mix in selected years between 1950–51 and 1992–93 are shown in Table 2.13. It is worth noting that oil and coal were the only fossil fuels used in the country in the early 1950s, and they together accounted for 98% of the primary energy supply. Following the development of natural gas reserves at Sui in the mid-1950s, gas has gradually substituted for coal and oil and now meets about 38% of the energy requirements. Furthermore, the construction of two large dams at Mangla and Tarbela has increased the share of hydro from a meager 2% in the early 1950s to around 15% now.

Table 2.13. Historical Pattern of Primary Commercial Energy Consumption

	1950–51	1960–61	1970–71	1980–81	1992–93
Total Primary Energy (Million TOE)	1.4	3.1	7.7	15.2	33.6
Share of Energy Sources (%)					
Coal	43.5	24.4	11.0	8.2	8.4
Oil	54.3	50.5	44.3	34.3	39.2
Gas	0.0	20.1	34.0	43.1	36.9
Hydro*	2.2	5.0	10.7	14.2	15.0
Nuclear*	0.0	0.0	0.0	0.2	0.4

* Conversion factor 10 550 GJ/GW h

Source Based on [14, 16]

Table 2.14 shows the course of domestic primary energy production in Pakistan in the last four decades by source. In the 1950s, coal and crude oil had the biggest shares in total domestic energy production but by the end of 1990 natural gas and hydro energy took over their role and became the major contributors. Although, coal production in Pakistan has been growing at a rate of 6% per annum, over time, there has been a 55 percentage point decrease in coal's share in total primary energy production. Similarly, crude oil production has been growing at the rate of 8% per annum but its share declined by 18 percentage point in 43 years time. Since the mid 1980s, there has been an upward trend in the growth rate of crude oil production leading to an increase in its share in the total production. In the last 37 years period, natural gas production has been increasing rapidly, i.e. at about 14% per annum. In the period 1955 to 1981, its share increased from 15% to about 64% but since then it has reduced to about 54%. Hydro is the fastest growing source of energy in Pakistan registering about 15% per annum growth rate. In the last four decades, the share of hydro energy has been gradually increasing (from 4% to 22%). On aggregate, the domestic energy production grew at a rate of 11% per annum. Since, in this period, the population growth rate was 3.1% per annum, the per capita domestic energy supplies expanded at the rate of 8% per annum.

Table 2.14. Indigenous Energy Production by Source

Unit: (000 TOE)

Year	Coal		Crude Oil		Natural Gas		Nuclear*		Hydro Energy*		Total
		%		%		%		%		%	
1950-51	214	65.0	102	31.1	0	0.0	0	0.0	13	4.0	329
1955–56	267	35.7	281	37.6	113	15.1	0	0.0	87	11.6	747
1960–61	391	26.4	307	20.8	626	42.4	0	0.0	154	10.4	1477
1965–66	807	26.2	445	14.4	1490	48.3	0	0.0	340	11.0	3082
1970–71	812	17.3	446	9.5	2614	55.7	0	0.0	823	17.5	4696
1975–76	690	10.8	337	5.3	3907	61.3	146	2.3	1297	20.3	6377
1980–81	1045	10.2	491	4.8	6556	63.7	36	0.3	2158	21.0	10285
1985–86	1466	9.8	1960	13.1	8146	54.4	103	0.7	3295	22.0	14969
1990–91	2043	9.8	3262	15.6	11 156	53.3	92	0.4	4369	20.9	20 922
1992–93	2181	9.6	3019	13.2	12 411	54.5	139	0.6	5039	22.1	22 790

* Conversion factor: 44.2 GJ/TOE
Source: Based on [14 & 16]

The dependence on imported energy has been declining over time in Pakistan. Through recourse to indigenous resources of gas and hydro, Pakistan has succeeded in reducing its overall energy import dependence from 77% in 1951 to about 32% in 1993. However, throughout this period, the country's import dependence for petroleum products has been quiet high. The oil crisis of 1970s highlighted the vulnerability of the economy on imported energy. In response, efforts were accelerated to develop indigenous energy resources especially crude oil and gas reserves. Despite expansion of domestic oil production, more than 86% of the petroleum products demand is still met by imported oil.

2.3.3. Oil Import Bill

The weakest link in the energy supply system of Pakistan has been the supply of oil from indigenous resources. The share of imported oil in the total oil consumption of the country hovered in the range of 80–91% until early 1980s. However, the share has now decreased to a level of nearly 77% owing to a relatively increased petroleum exploration and development activity during the 6th and 7th Five Year Plan periods (1983–1988, 1988–1993) (see Table 2.15).The oil import bill is a major strain on Pakistan's economy and has been siphoning off a large portion of its export earnings (see Table 2.16). Apart from physical constraints on crude oil production, its availability and price in the international market are subject to various geo-political factors. This makes the supply and price of oil quite unreliable, and the high dependence on the imported energy increases the dependence of the economy on the international market at an unacceptable high level. At present, the softening of oil prices in the international market since 1986 has provided some relief to Pakistan.

Table 2.15. Shares of Imports in Total Primary Commercial Energy Consumption in Pakistan

(000 TOE)

	1950–51			1960–61			1970–71			1980–81			1992–93		
	Total	**Imports**	**Share of Imports**	**Total**	**Imports**	**Share of Imports**	**Total**	**Imports**	**Share of Imports**	**Total**	**Imports**	**Share of Imports**	**Total**	**Imports**	**Share of Imports**
Oil	766.6	664.2	87%	1568.4	1261.9	80%	3405.8	2959.4	87%	5218.4	4727.9	91%	13 174.8	10 155.3	77%
Coal	613.3	399.4	65%	757.6	367. 1	48%	847.9	35.7	4%	1249.9	204.9	16%	2834.9	653.9	23%
Gas	0.0			625.7			2614.3			6555.5			12 411.4		
Nuclear	0.0			0.00			0.2			35.8			138.9		
Hydro	31.0	18.0	58%	154.0	0.0	0%	823.3	0.0	0%	2158.5	0.0	0%	5039.2	0.0	0%
Total	1411.0	1081.6	77%	3105.7	1629.00	52%	7691.5	2995.1	39%	15 218.1	4932.8	32%	33 599.3	10 809.2	32%

* Imported electricity from India

Source: Based on [14 & 16]

Table 2.16. Quantity of Oil Imports and Oil Import Bill of Pakistan

Year	Oil Imports (10^6 TOE)	Oil Imports Bill (10^6 \$)	% of Export Earnings Spent on Oil Imports
1972–73	3.7	62	8
1973–74	4.1	152	15
1974–75	4.0	337	33
1975–76	4.0	378	33
1976–77	4.1	413	36
1977–78	4.7	497	38
1978–79	5.1	530	31
1979–80	5.6	1079	46
1980–81	5.8	1535	52
1981–82	6.2	1710	69
1982–83	6.3	1616	60
1983–84	6.7	1421	51
1984–85	6.5	1435	57
1985–86	6.5	1039	34
1986–87	7.1	814	22
1987–88	7.8	1047	23
1988–89	8.0	963	21
1989–90	9.0	1163	23
1990–91	8.7	1687	27
1991–92	9.6	1385	20
1992–93	11.0	1531	23
1993–94	12.1	1419	22

Source: Based on [10]

2.4. Energy Resources

2.4.1. Indigenous Energy Resources

The proven reserves of fossil fuels in Pakistan are extremely small; they correspond to only 7 TOE per capita. As on June 1994, total proven fossil fuel reserve of Pakistan are:

Gas	23	Trillion Cubic Feet	=	408	million TOE
Oil	198	Million barrels	=	27	million TOE
Coal	1075	Million tons	=	481	million TOE
		Total	=	916	million TOE

Compared to other groups of countries, the per capita fossil fuel reserves in Pakistan in 1993 were 6 TOE compared to 143 TOE per capita in the world and 290 TOE in the OECD countries. Coal has the largest resource potential in the country, in addition to 1075 million tons of its proven reserves, there exist 6089 million tons of indicated coal reserves and about 69 billion tons of inferred coal reserves, while the total coal resource potential of the country is estimated to be about 185 billion tons [14]. However, the quality of proven coal reserves is very poor since it has high ash & high sulphur content and its heating value is only about 50% of that of standard coal.

Oil and Gas: Although the proven reserves of fossil fuels are rather small, the estimated fossil fuel resources potential is quite promising. About 800 000 square kilometers area in Pakistan consists of sedimentary basins (onshore: 600 000 sq. km., offshore: 200 000 sq. km.). The speculative ultimately recoverable petroleum resource potential of Pakistan has been estimated as 5–7 billion TOE of oil and about 3.5 billion TOE of gas [17]. The oil and gas reserves discovered so far correspond to less than 1% of the above estimated oil potential and about 11% of the gas potential. The fact that only a small fraction of this potential has been discovered so far is probably due to insufficient exploratory efforts.

Most of the sedimentary basins of Pakistan (except Potowar and Badin blocks) are generally believed to be predominantly gas prone. The relatively high size of gas resource discovery is due mainly to four major fields: Sui (192 million TOE), Mari (70 million TOE), Pirkoh (81 million TOE) and Qadirpur (85 million TOE) which were discovered in 1952, 1957, 1977 and 1990, respectively. The new additions to gas reserves since the mid 1983, amount to only 131 million TOE[2] inspite of the relatively increased exploratory effort during the 6th and 7th Plan periods. Of a total of 376 exploratory wells drilled in Pakistan till the mid 1994, 186 were drilled by the mid 1983, while 164 wells have been drilled during the 6th and 7th Plan periods.

The total exploratory wells drilled so far make the drilling density of 0.47 well per 1000 sq. km in Pakistan, compared to 7 wells per thousand squares kilometers for developing countries, as one of the lowest in the World. The 8th Five Year Plan envisages drilling of 142 exploratory wells during the plan period (1993–1998). It is envisaged that by the end of the 8th Five Year Plan period, the annual production of natural gas will become 18.8 million TOE as against 12.4 million TOE in 1992–93 resulting in a growth rate of 8.6 % per annum.

There are many uncertainties in the above mentioned estimates of speculative ultimately recoverable oil and gas resource potential of the country, and these estimates still need to be substantiated by the results of a sizable exploratory effort — much larger than what has been undertaken so far. Still the experts of this field are quite optimistic about the possibility of finding significant quantities of oil and gas reserves.

In the past, various measures were taken to enhance exploration of oil and gas resources and development of their proven reserves. However, due to a number of institutional, procedural and policy issues, this could not be achieved. In the current Petroleum Policy, which is a revised version of the policy announced in November 1991, several additional incentives for producers' prices, market assurance and taxes have been offered to increase oil exploration activities in general, and of gas in particular.

Coal: As of the mid-1994, the total geological resources of coal in Pakistan amount to 185 billion tons of which only 0.6% corresponds to proven reserves and the rest consist of indicated (3%), inferred (37%) and hypothetical (59%) resources [14]. The major coal fields are Lakhra, Sonda and Thar. Lakhra, with about 1.3 billion tons of resources, is the most thoroughly investigated coal field of the country. Lakhra coal is lignite to sub-bituminous quality with high ash (19.2%) and sulphur (5.5%) content. Its heating value is 6,088 BTU/lb (0.0142 GJ/kg), Major coal seam has an average thickness of 1.8 meters. Some parts of the Lakhra field are suitable for underground mining (which is currently being practiced), while surface mining in other fields is possible with average stripping ratio of about 14:1. The Sonda coal field,

[2]23 TOE = 1.06 times 10^{12} joules.

discovered in 1981, has 3.7 billion tons of coal resources. Based on relatively limited investigations, it has been found that coal in the Sonda field is much deeper (80% resources are between 150 to 300 meters) than Lakhra field but its quality is better (ash; 15.8%, sulphur; 2.7% and heating value; 8506 BTU/lb (0.019784 GJ/kg)). If necessary investments are made, it is expected to prove 0.5 to 1 billion tons of mineable reserves in Lakhra and Sonda fields in the next few years.

The recently discovered Thar coal field, in the province of Sind, accounts for about 95% of the coal resources in Pakistan. The quality of Thar coal field is yet to be determined reliably. Huge capital expenditure extending over a long period of time will have to be incurred in order to establish the Thar coal resources and develop the necessary mining infrastructure.

Most of the coal found in Pakistan is very poor in quality; it has very high sulphur, ash and moisture content, which makes its use unsuitable for domestic and most of the industrial applications. However, it can be used for power generation based on advanced technologies (e.g. flue gas desulphurisation, fluidised bed combustion) provided large scale economical mines may be developed for this purpose.

Over 90% of the coal production is from private mines. All existing coal mines in Pakistan are underground, and labour intensive primitive mining methods are used to produce coal from these mines. Constraints which have so far hindered the expansion in use of indigenous coal include its poor quality, limited markets (over 90% of the present coal production is used by brick kilns), uncertainty regarding the quantity of recoverable reserves and lack of experience about coal production costs from a modern mine in Pakistan's environment. The domestic coal market can be expanded in a big way if coal can be economically used for power generation while meeting acceptable environmental standards. Recently two 50 MW units, using atmospheric fluidised bed combustion (FBC) technology have been commissioned, one unit is expected to be commissioned in 1996 and three more units are planned to demonstrate the economic and environmentally acceptable use of indigenous coal in power generation.

Hydro Power: Pakistan has an identified hydro power potential of about 30 000 MW [8] of which 4825 MW has already been developed while an additional 1634 MW (Ghazi Brotha 1450 MW, Chashma 184 MW) is under development.

There will be considerable difficulties in further expansion of hydropower. This is because the most attractive sites have already been developed and the cost of construction of new dams is increasing with increasing complexity of dams at less favourable sites. Further, in most cases new sites are far away from the demand centers, thereby necessitating huge additional investment in transmission lines and, still having their generated electricity subject to substantial transmission losses. In view of these and other constraints (e.g. dislocation of people, submergence of agricultural land, etc.), it would be unrealistic to assume that much more than half of the hydro potential in the country will be exploited in the next three decades.

New and Renewable Energy Sources: There are many forms of renewable energy sources such as biogas, wind energy, solar energy, geothermal and ocean energy which though environmentally congenial, are not being used at commercial scale until now. Among these technologies, solar energy, biogas plants and wind energy have been used in some places in Pakistan, particularly in the rural areas.

Biogas: The organic wastes from animals, humans, agricultural residues and household wastes potentially contain enough energy to contribute significantly to the energy supply in many areas, particularly in the remote rural regions. In the country, many family-size biogas units (2–5 m^3 per day) have been installed on a demonstration basis by the Directorate General of New and Renewable Energy Resources (DGNRER) and by the Pakistan Council of Appropriate Technology. A few larger units have also been installed on a demonstration basis. Despite the potential of this technology, and although the country is rich in renewable biomass resources, only some 4000 units have been installed up till now, and most of these are not operational. Another disappointing failure, with the working units evaluated in the field is that the gas pressure of these units is usually low, particularly in winter, so that the operating units are not in a condition to replace other sources of energy in these areas.

Substantial advances have been made in biogas technology in recent years, with improved fermentation technologies now available for specific wastes. But there is a need to work out a strategy for promotion of biogas programme in Pakistan at a large scale. In the 8th Five Year Plan the policy for renewable energy resources includes promotion of forestry, better utilization and distribution of crop residues, improvements in efficiencies of biomass utilization and, improvement in the market structure for fire-wood and crop residues.

Solar Energy: Pakistan lies in the latitude which has large solar radiation potential. Consequently it has long sunshine hours and high insulation levels. The level of insulation varies considerably over the year especially during the summer. The Meteorological Department records the solar radiation data along with other information, such as drybulb and wetbulb temperature, sunshine hours, rainfall, wind speed and so on at three-hour intervals. The maximum average value of solar radiation is 709 cal/cm^2 and lowest values is $244/cm^2$ [18].

The Solar Energy Centre of the Pakistan Council for Scientific and Industrial Research (PCSIR) is planning a wind and solar energy project and the National Institute of Silicon Technology is also working in the area of solar radiation and their applications in the country. A total of 20 solar power stations with capacity of 0.45–57 kWp, have been installed in the country. In view of the high capital costs of solar and wind energy systems, it is not expected that these resources can be harnessed in the near future. However, there are some remote areas in the country, where supplying energy through conventional energy systems becomes more expensive than through renewable resources. To provide energy in these areas, it has been planned to promote the use of renewable energy systems. During the current Five Year Plan period, emphasis has been placed on demonstration and utilization of these energy sources in the remote areas.

Wind Energy: Pakistan has little experience with wind energy conversion technology. Two wind electricity generators of 20 kW capacity each have been installed by DGNRER, and some wind-driven water-pumps have been installed by a private company (Merin Ltd.).

The major technical uncertainty with wind energy is the lack of adequate and reliable data on the wind resources. The main source of wind speed data in Pakistan is the Meteorological Department. The collected data is suitable only for identification of the probable sites for installation of wind turbines. Relatively higher wind speeds in the southern part of the country are due to intense heating of the ground. The average wind velocity in the northern parts of the country is much below than the required values. Thus, these parts do not offer much potential for wind energy utilization. According to the recent energy policy, a wind resource programme would be initiated to formulate projects on location basis.

Other renewable energy sources e.g. geothermal energy and ocean energy are also available in Pakistan, but no significant surveys have been done to estimate these resources.

2.4.2. Prospects of International Supply of Fossil Fuels

Due to population and economic growth, the world energy demand is increasing. About 70% of the world's population lives at a per capita energy consumption level one-quarter of that in Western Europe, and one-sixth of that in United States of America. The world is heavily dependent on fossil fuel resources and it will take considerable time for transition to alternative energy supply strategies. Thus, the demand for coal, oil and natural gas is likely to rise for the next few decades. Coal is the only fossil fuel source which is likely to be available in substantial quantities much beyond the middle of the next century.

Table 2.17 lists the global potential of various fossil fuel resources together with the cumulative requirements of these fuels from 1990–2020, as per estimates of the World Energy Conference [19]. If one considers the total of all fossil fuels, without making any distinction in term of oil, gas, and coal, even the proven reserves alone are more than three times the cumulative requirements. If one also takes into consideration the estimated additional reserves, 95% of the global potential of fossil fuel resources would still remain available even after 2020. This apparently comfortable situation arises only when coal is taken at par with oil and gas without any consideration to the unsuitability of coal for various uses (e.g. as motor fuel, chemical feedstock, household fuel etc.) and the difficulties inherent in its mining, transportation, handling etc. The situation changes if one considers oil, gas and coal separately. It then turns out that the total proven reserves of oil are only 40% higher than the cumulative requirements of oil, while the proven global reserves of gas are 80% higher than the cumulative requirements of gas. This points to a comfortable situation only on a global basis. If regional aspects are also taken into account, the actual situation will be found to be much more complex. This is because the world resources of fossil fuels are not evenly distributed, e.g. the Middle East countries with only 3% share in present global energy consumption, command about two-thirds of the world's proven reserves of oil and one third of those of gas. Since the petroleum-resource-rich countries would not like to use their reserves of oil and gas to get completely exhausted within the next two or three decades, the international availability of these fuels will become increasingly more difficult and expensive with time.

The world will thus need to turn to relatively much more expensive unconventional liquid and gaseous fuels, e.g. those derived from coal liquefaction/gasification, exploitation of oil-shales, tar-sands and deep off-shore oil and gas etc. The world resources of unconventional petroleum are believed to be much larger than those of conventional oil and gas. However exploitation of these resources will not only be expensive but will also result in serious environmental degradation. The same consideration also applies to conversion of coal into gaseous and liquid fuels. Further, in the case of coal, roughly 85% of the global resources are held by only three countries : USA, Russia and China. In view of the safety and health risks involved in coal mining activities and serious environmental degradation caused by them, it is an open question whether these and other coal-rich countries will be willing to produce coal much in excess of their own needs. As such, even the long term availability of coal in the international market will be very much constrained by the adopted policies of the above three countries.

Table 2.17. Prospects of International Supply of Fossil Fuels

(GTOE)

	Oil	Gas	Coal	Total
Proven Reserves	137	108	606	851
Ultimately Recoverable Reserves	200	220	3400	3820
Total Reserves	337	328	4006	4671
Cumulative Demand (1990–2020)	99	60	82	241

Source: [19]

2.5. Electricity Sector Development

2.5.1. Organizational Setup for the Electricity Sector

The responsibility for overall planning and coordination of the energy sector including electric power rests with the Energy Wing of the Pakistan Planning Commission. Since the mid-1980s efforts have been made to induct private sector in power generation but up till now, the power industry is essentially a public owned enterprise. In accordance with the guidelines recommended by the Planning Commission, the Ministry of Water and Power frames the policies for the electricity sector and oversees the implementation of these policies and development plans by the utilities. Except for generation of nuclear power, which is the exclusive responsibility of Pakistan Atomic Energy Commission (PAEC), the generation, transmission and distribution of electric power in the country is handled by two organizations: Water & Power Development Authority (WAPDA) and Karachi Electric Supply Corporation (KESC). The domain of WAPDA extends over the whole country except about 2400 sq. km area around Karachi which is licensed to KESC. At present PAEC is operating only one nuclear power plant (137 MW) which is located near Karachi. The power generated by this plant is supplied in bulk to KESC.

2.5.2. Historical Growth of Electricity Consumption

The electricity consumption in Pakistan has been growing over the last 32 years at an average rate of 11.8% per annum, which is twice as high as the GDP growth (5.7% p.a.) and 4 times of the growth rate of per capita GDP (2.6% p.a.) in the same period. Table 2.18 shows the total electricity consumption and its sectoral break up from 1961 to 1993. The consumption of the Residential sector has grown much faster than the average growth in total electricity demand, registering around 14% p.a. growth. Rural electrification and air-conditioning are the main factors responsible for the relatively fast growth of demand in this sector.

Among the production sectors, the maximum growth was experienced in the Agriculture sector - more than 50 time increase in the last 32 years. This was due to a sharp increase in the demand of electricity for irrigation. Due to the limited supply potential of canals, the expansion in irrigation has been mainly based on tubewells. In 1960–61, the availability of water at farm gate was 59 million acre feet (72.8×10^9 m^3), of which only 2.3 MAF (2.8×10^9 m^3) was supplied by tubewells (i.e. 4%). In 1992–93, water availability increased to 125 MAF (154.2×10^9 m^3), while the share of tubewell water increased to 37%, i.e. 46 MAF (56.7×10^9 m^3) [7]. Further, with rising oil prices and a relatively smaller increase in electricity price for the Agriculture sector, there has been a trend to switch over from diesel operated tubewells to electric pumps wherever electricity is available. It is estimated that the present total connected load due to irrigation pumps amounts to about 1172 MW. Electricity demand from the Industrial and Service sectors have also been growing at a high rate (i.e. 10% p.a.). However, the growth rates for these sectors have been smaller than the overall growth rate of electricity demand.

Table 2.18. Historical Growth of Electricity Consumption by Economic Sectors

Million kW·h

	1960–61	1965–66	1970–71	1975–76	1980–81	1990–91	1992–93
Agriculture	102 (9.8)	480 (17.9)	1072 (20.9)	1395 (20.1)	2135 (18.8)	5620 (17.8)	5635 (15.4)
Industry	615 (59.2)	1 420 (52.9)	2498 (48.7)	3113 (44.9)	4525 (39.7)	11 229 (35.6)	13 043 (35.7)
Transport	– (–)	– (–)	43 (0.8)	45 (0.7)	44 (0.4)	33 (0.1)	27 (0.1)
Residential	185 (17.8)	358 (13.3)	619 (12.1)	1128 (16.3)	2696 (23.7)	10 409 (33.0)	13 170 (36.1)
Services	137 (13.2)	429 (15.9)	900 (17.5)	1252 (18.0)	1985 (17.4)	4243 (13.5)	4617 (12.7)
Total	1039	2687	5132	6933	11 385	31 534	36 492

Figures in parentheses are % shares of the total

Source: [14]

Table 2.18 also gives the shares of different sectors in total electricity consumption. It is seen that the share of Residential has increased from 18% in 1961 to 36% in 1993 due to large expansion in residential connections both in the urban and rural areas. The share of Industry has decreased from 59% in 1961 to 36% in 1993. The share of the Agriculture sector in the total electricity consumption increased during the 1960s due to increased use of electricity for irrigation water pumping. This share remained almost constant during the 1970s but declined during the 1980s due to higher growth of electricity consumption in other sectors. A part of railways track was electrified in 1970. Since then no further expansion in electrification of railways has been done. The share of the Transport sector in electricity consumption is now only 0.1%.

Table 2.19. Evolution of Installed Electricity Generation Capacity in Pakistan

(MW)

	1970–71	1980–81	1990–91	1994–95
Hydel	667	1567	2897	4825
Share in Total (%)	(41.17)	(44.80)	(35.92)	(38.50)
Thermal	953	1806	5043	7572
Oil/Gas Steam	823	1168	2920	4340
Share in Total (%)	(50.80)	(33.39)	(36.21)	(34.63)
Domestic Coal Steam	15	15	15	115
Share in Total (%)	(0.93)	(0.43)	(0.19)	(0.92)
Combustion Turbines	115	623	1508	1108
Share in Total (%)	(7.10)	(17.81)	(18.70)	(8.84)
Combined Cycle	–	–	600	2009
Share in Total (%)	–	–	(7.44)	(16.03)
Nuclear	–	137	137	137
Share in Total (%)	–	(3.92)	(1 70)	(1.09)
Total	1620	3498	8065	12 534

Table 2.20. Installed and Effective Power Capacity (1994–95)

(MW)

Type of Power Station	Installed Capacity	Effective Capacity	
		Maximum	Minimum
Hydel			
Tarbela	3478	3524	1242
Mangla	1000	1035	612
Warsak	240	225	143
Small Plants	107	70	40
Sub total	4825	4854	2037
Thermal			
Oil/Gas Steam	4340	na	
Domestic Coal Steam	115	na	
Combustion Turbines	1108	na	
Combined Cycle	2009	na	
Sub total	7572	7572	
Nuclear	137	70	
Total	12 534	12 496	9679

Source [14]

2.5.3. Power Generation Capacity

Table 2.19 shows the evolution of power generation capacity of Pakistan over the last 25 years. The share of hydro capacity has remained around 40% percent during this period, while the share of thermal plants has varied between 55–60%. There is a small increase in power generation capacity based on coal, while the nuclear power capacity has remained unchanged at 137 MW level since 1971. The present installed capacity is about 12 534 MW comprising 38% hydro, 35% oil/gas steam, 9% combustion turbines, 16% combined cycle, 1% coal and 1% nuclear.

Table 2.20 gives the breakdown of the installed capacities and their effective maximum and minimum capabilities. The large differences between the maximum and minimum capabilities of the hydroelectric plants are due to seasonal variations in the reservoir levels and water release patterns, the later being dictated by irrigation requirements. In the case of thermal plants, effective capabilities correspond to derated capacities as a result of wear and tear of the units. The firm capability as shown in Table 2.20 is about 78% of the installed capacity.

2.5.4. Power Capacity Shortages and Load Shedding

The electricity demand reported in Table 2.18 has in fact been a suppressed demand since the early 1980s. In 1981–82 about 20% of the peak load was not supplied [20]. The number of pending applications for new connections was 180 thousand, and most of the industrial units were restricted to only two shifts during the winter months when the hydro generation capacity was at its lowest. Since then load shedding has now become a common practice in Pakistan.

Despite a 100-fold increase in the power generation capacity over the last four decades, the supply of electricity is still unable to keep pace with the demand. The peak demand has been exceeding supply capability by about 15–25% in the recent years, requiring load shedding of 1000–1500 MW each year. This level increased to about 2470 MW in 1994. Apart from causing inconvenience to the general public, these power shortages are estimated to be resulting in a reduction of annual gross domestic product by about 2% with a loss of about $50 million per annum in industrial value added and an estimated $150 million per annum reduction in the country's exports of manufactured goods.

The government has recently taken concrete steps to reducing power shortages in the country through quickly building new power plants both in public and private sectors and by containing the demand through load management measures. It is planned to eliminate load shedding by 1998.

2.5.5. Historical Pattern of Power Generation

In 1950–51, the total electricity generation in Pakistan was only 257 GW·h. During the 44 year period, (1951–1995), electricity generation grew at the rate of 13% p.a. Among the various sources of electricity generation, the most significant expansion has been in generation from hydro units, which, starting from 73 GW·h in 1951, registered more than 300 fold increase (see Table 2.21) till 1995. Similarly, generation from oil based units has also been growing rapidly from 184 GW·h in 1951 to 15 742 GW·h in 1995. In the country, electricity generation from gas started in 1961 with total generation of 527 GW·h which witnessed a 27 fold increase in the 34 year period (1961–1995).

Table 2.21. Historical Pattern of Electricity Generation by Source

(GW·h)

Year	Nuclear	Hydro	Coal	Gas	Oil	Total Generation
1950–51	0 (0.0)	73 (28.4)	0 (0.0)	0 (0.0)	184 (71.6)	257
1955–56	0 (0.0)	391 (57.6)	0 (0.0)	0 (0.0)	288 (42.4)	679
1960–61	0 (0.0)	645 (49.7)	0 (0.0)	527 (40.6)	126 (9.7)	1298
1965–66	0 (0.0)	1424 (38.5)	178 (4.8)	1897 (51.3)	200 (5.4)	3698
1970–71	0 (0.0)	3450 (47.9)	202 (2.8)	3342 (46.4)	209 (2.9)	7202
1975–76	609 (5.9)	5438 (52.7)	62 (0.6)	3715 (36.0)	495 (4.8)	10 319
1980–81	145 (0.9)	9043 (56.3)	48 (0.3)	6264 (39.0)	562 (3.5)	16 062
1990–91	369 (0.9)	18 264 (44.5)	41 (0.1)	13 174 (32.1)	9193 (22.4)	41 042
1994–95	511 (1.0)	22 858 (42.7)	40 (0.1)	14 394 (26.9)	15 742 (29.4)	53 545

Figures in parentheses are percentage share in total generation

Source: Based on [14 & 16]

Table 2.21 also shows the pattern of electricity generation during the 1951–1995 period, at five-year intervals. Since 1961, hydro and gas have been the main sources of electricity generation providing above 90% of the total requirements. Oil was the only source of thermal generation until 1956 and contributed 72% of the total generation in 1950–51 and 42% in 1955–56. During the 1970s, the share of oil was reduced rapidly, first due to build up of hydro capacity and later on due to use of natural gas for power generation. The oil share reached an all time low level of 0.5% in 1978–79, but has increased again to about 34% due to the shortage of gas in the recent years. The share of coal in electricity generation has been quite insignificant. A 15 MW coal fired plant based on indigenous coal was installed in 1964, after about 30 years, two coal fired units of 50 MW capacity each have been commissioned and one more unit with the same capacity is expected to be commissioned in 1996. Nuclear power was introduced in 1971 with the commissioning of a 137 MW plant at Karachi. The share of nuclear power in electricity generation was about 6% during the period 1973–1976, but has decreased since then. During 1994–95, the shares of electricity generation by source were: hydro 43%, gas 27%, oil 29% and nuclear and coal combined were about 1%.

2.5.6. Grid System

The two electric systems operated respectively by WAPDA and KESC were interconnected in 1985 with a double circuit 220 kV transmission line from Jamshoro to Karachi. Until 1970 the principal transmission lines in the country were designed and built for operation at 66 and 132 kV. In 1970, the first 220 kV line was installed and thereafter successive 220, 132, and 66 kV lines were built, forming a power system grid from Tarbela and Mangla hydel plants in the north to the principal load centers and thermal power plants up to Hyderabad/ Jamshoro in the south.

In order to improve the efficiency of its transmission network and to cope with increasingly large power flows, WAPDA built extra high voltage (EHV) lines that operate at 500 kV. The first (330 km) of these lines was completed in 1977–78; it transmits power from Tarbela to the Faisalabad area where it is connected to the 220 kV and 132 kV grids. Table 2.22 gives the details of the WAPDA's existing network of 500 kV transmission lines. In the long run, it is proposed to connect future large hydroelectric plants with the system using ultra high voltage (UHV) AC lines (higher than 500 kV) or high voltage direct current (HVDC) lines.

The present transmission network is about 25 805 km long consisting of : 2803 km of 500 kV lines, 1943 km of 220 kV lines, 12 800 km of 132 kV lines and 8259 km of 66 kV lines. There are about 604 grid sub-stations in service. Power is distributed at 11 kV and, for short distances, at 400 Volts in most parts of the country.

Table 2.22. 500 kV Transmission Lines

Name of Scheme	Route Length	Date of Completion
First Circuit Tarbela-Faisalabad	330	1977–78
Faisalabad-Multan-Guddu-Karachi		
Faisalabad- Multan	209	February, 1981
Multan-Guddu	310	November, 1981
Guddu-Jamshoro	438	December, 1984
Second Circuit Tarbela-Faisalabad	327	July, 1985
Second Circuit Lahore-Multan-Jamshoro		
Lahore-Multan	318	January, 1990
Multan-Kot Chatta	122	May, 1991
Kot Chatta-Guddu	190	May, 1991
First Circuit Tarbela-Peshawar		
Tarbela-Peshawar	117	November, 1992
3rd Tarbela-Lahore		
Tarbela-Lahore	347	August, 1993
3rd Jamshoro-Guddu-Multan and 2nd Multan-Gatti-Lahore		
Gatti-Lahore	95	October, 1993
Total	2803	

Source [21]

2.5.7. Power System Losses

The power systems losses in the WAPDA and KESC systems, including auxiliary consumption, are shown in Table 2.23 for the last two decades. Until 1976–77 power losses in the WAPDA system were increasing. In the late 1970s WAPDA initiated a crash programme to reduce the power losses by upgrading the primary transmission system, improving the efficiency of the secondary systems and through better management. It was planned to reduce the total system losses to about 23% by 1990. The utility was successful in achieving the target. However, in the recent years, losses in the WAPDA's power system have started increasing again.

Table 2.23. Auxiliary Consumption & System Losses of WAPDA & KESC

(% of total generation)

Year	WAPDA	KESC
1972–73	32.7	15.7
1973–74	34.0	16.5
1974–75	35.2	16.8
1975–76	35.8	17.6
1976–77	37.6	20.2
1977–78	35.7	20.3
1978–79	34.2	20.7
1979–80	32.7	20.8
1980–81	31.3	27.2
1981–82	30.3	22.6
1982–83	29.7	25.6
1983–84	29.3	24.8
1984–85	26.7	22.2
1985–86	26.4	21.9
1986–87	24.9	23.6
1987–88	24.6	23.5
1988–89	23.9	24.2
1989–90	23.2	25.6
1990–91	22.8	28.4
1991–92	23.1	30.8
1992–93	23.3	33.6

Source: [21]

The power losses of the KESC system were significantly lower than the losses in the WAPDA's system. Since 1989, the losses in the KESC system have been increasing and have become much higher than those of the WAPDA's system. These losses are mostly due to a poor and overloaded distribution system. In 1993–94 the total power losses of the two systems were about 29%. It is believed that a part of these losses is due to "theft" by some consumers. The utilities estimate that about 5–10% of the total generation is lost on this account. Efforts are being made to reduce T&D losses through a number of measures. The main measures being adopted for this purpose are:

(1) Installation of low voltage capacitors;

(2) Installation of anti–theft meter boxes;

(3) Resealing of existing anti–theft boxes;

(4) Installation of three phase meters in premises where three phase supply has been given through single phase meters;

(5) Replacement of defective meters;

(6) Bifurcation of overloaded feeders through augmentation and extensions;

(7) Re-conductoring of primary lines;

(8) Installation of express feeder;

(9) Replacement of over loaded transformers;

(10) Conversion of LT lines to HT lines;

(11) Checking of defective meters.

2.5.8. Tariffs

The evolution of electricity tariffs during 1970–1994 is shown in Table 2.24. The two major guiding principles in fixing these tariffs have been: (i) assurance of an adequate financial return to the power generating authorities which can enable them to support a part of their investment programmes from their own resources and (ii) protection to the Residential and the Agriculture sectors from high electricity prices. In the early 1980s, it was decided, in consultation with the international donor agencies, that electricity tariffs should be raised to enable the utilities to finance 40% of their average tri-annual investment programme. As a result, since 1984–85, the level of electricity tariff has been increased almost annually. In nominal terms, the average revenue of WAPDA has increased from 51.69 Paisas/kW·h in 1981 to 124.09 Paisas/kW·h in 1993–94, representing an average annual increase of 6.5%. In addition, over time, there has been significant increase in the indirect taxes on electricity sales resulting in a significant increase in purchasers' prices of electricity. However, this increase has not fully checked the high growth in electricity demand. According to a recent study, the price elasticities of electricity demand are quite low in Pakistan; in the range of –0.09 to –0.40 for the major consumer groups [20].

Table 2.24. Electricity Tariffs in Pakistan

Category of Consumer	1970	1975	1980	1994
Domestic	25 Paisas/kW·h + Rs 2 0/month	20–25 Paisas/kW h + Rs 2 0/month	34–70 Paisas/kW·h + Rs 5.0/kW/month	54–134 Paisas/kW·h + Rs.10 0/kW/month
Commercial	25 Paisas/kW h + Rs 2 0/month	43 7–49 Paisas/kW h + Rs 4 0/month	90–100 Paisas/kW·h + Rs 15 0/kW/month	196–218 Paisas/kW·h + Rs 34 0/kW/month
Industrial				
70 kW Load	15 5 Paisas/kW·h + Rs.5 0/kW/month	29 9 Paisas/kW h +Rs 8.74/kW/month	57 Paisas/kW·h + Rs 25.0/kW/month	108 Paisas/kW h + Rs 49 0/kW/month
Up to 500 kW Load	8 0 Paisas/kW·h + Rs.16 5/kW/month	16.8 Paisas/kW·h + Rs.28 87/kW/month	36 Paisas/kW·h + Rs 62.0/kW/month	62 Paisas/kW·h + Rs 138.0/kW/month
High Loads	7 5 Paisas/kW h + Rs 15 0/kW/month	16 Paisas/kW h + Rs.26.22/kW/month	35 Paisas/kW·h + Rs 57 0/kW/month	61 Paisas/kW h + Rs.134.0/kW/month
Tube Wells				
For Reclamation & Drainage	9 Paisas/kW·h	14.6 Paisas/kW h	36 Paisas/kW·h	79 Paisas/kW h
For Irrigation	6 Paisas/kW·h + Rs 5 0/kW/month	9 5 Paisas/kW h + Rs 7 25/kW/month	22.3 Paisas/kW·h +Rs 14.0/kW/month	45 Paisas/kW·h + Rs.38 0/kW/month

Note

1 Rupee	=	100 Paisas
1 US $	=	6.41 Rupees (Rs.) in 1970, and
	=	9 90 Rupees in 1975 and 1981
	=	30.16 Rupees (Rs.) in 1994.

Source. [21]

2.5.9. Induction of Private Power Sector

The main reason behind shortage of installed capacity has been the unavailability of adequate investment funds. In order to overcome this difficulty, the Government has for sometime been trying to induct private sector into power generation. However, up till now, only one power project has been launched. Construction of the first private power plant (a 1300 MW oil fired thermal power plant) was started in 1992 and its first unit is expected to become operational in early 1996, Recently a new policy for private power generation has been announced which offers attractive incentives to the private investors. The salient features of the new policy framework are given below [22].

(1) Investors are free to choose any site and opt for any technology and fuel type, except hydro resources of the main river Indus and the nuclear power technology.

(2) The bulk power tariff has been set as US Cents 6.5/kW·h (to be paid in Pak. Rupees for sales of electricity to WAPDA and KESC) in the first ten years of project operation,

while a levelized tariff over life of the project has been set as of US Cents 5.9/kW·h. In addition to this, a premium of US Cent 0.15/kW·h has been offered to the projects of above 100 MW capacity which are commissioned by the end of 1997 under this scheme.

(3) Both the local and foreign investors are allowed to participate in power generation activities. The Government has established a Private Sector Energy Development Fund (PSEDF) with the assistance of the World Bank, USAID and other multilateral lending agencies. PSEDF may provide loan to the private power company to finance up to 40% of the capital costs of a project, currently at a fixed interest rate of 14% per annum with a maturity period of up to 23 years including a grace period of up to 8 years

(4) Various incentives such as permission to issue Corporate Bonds and shares at discounted price have been given to both foreign and local companies to facilitate the creation of a corporate debt securities market for the power sector.

(5) Some fiscal incentives are exemption from corporate income tax and various types of indirect taxes (custom duties, sales tax, Iqra tax, Flood relief tax) on import of plant and equipment for power generation.

This package of incentives is applicable to projects which will be commissioned before 1998. Projects to meet capacity requirement beyond 1998 will be selected through a competitive bidding process, and will be required to use indigenous fuels, particularly coal and hydro resources.

The response to the new private power generation policy has been quite encouraging: (1) Eleven projects (excluding Hub) totaling 2028 MW achieved financial closure/construction start till March 1996 (see Table 2.25 for details). All these projects are planned to be operational by the end of the 8th Five Year Plan. (2) 33 projects of total 7,637 MW capacity are under negotiation. These projects have letters of support from the Private Power and Infrastructure Board (PPIB). Of these projects, it is expected that a total around 3000 MW capacity would be available by June 1998 (see Table 2.25 for details of some selected projects). (3) Various projects, with supported and unsupported proposals are under-discussion (see Table 2.25).

The Transmission system policy for the Private Sector has also been introduced. The fourth 500 KV line from Jamshoro-Moro-Rahim Yar Khan-Sahiwal-Lahore and between Muzaffargarh to Faisalabad of approximately 1440 km and associated grid station will be constructed by a UK Company.

In addition to building up of new capacity in the private sector, the Government of Pakistan also plans to privatize nearly 6000 MW of its existing thermal power generating assets. In the first phase, 26% shares of the 1600 MW gas and oil fired Kot Addu power plant have been sold to the private sector. WAPDA will eventually sell all its thermal power plants, retaining only its hydro generation capacity. The Government has also drawn up plans to privatize the country's other large utility, Karachi Electric Supply Co., which will sell plants of 1400 MW capacity. Moreover, the Government will privatize the Faisalabad Area Electricity Distribution System, which serves about 1 million customers in the central Punjab region.

Table 2.25. Private Power Projects (As on March-1996)

Private Company	Type of Plant/Fuel	Capacity (MW)	Investment Cost (Million $)	Year of Commissioning
Financially Closed				
Hub Power Ltd.	Fuel oil	1300	1882	1996*
AES Lal pir Ltd.	Fuel oil	337	375	1997
AES Pakgen Ltd.	Diesel oil	336	349	1997
Davis Energen (Pvt) Ltd.	na	10	12	1997
Gul Ahmed Energy Ltd.	na	125	138	1997
Habibullah Energy Ltd.	na	140	156	1997
Japan Power Generation Ltd.	Diesel oil	107	123	1997
Kohinoor Enerygy Ltd.	Natural Gas	120	139	1997
Power Generation System Ltd.	na	110	140	na
Southern Electric Power Ltd.	na	112	119	1997
Hawkins Uch Power	Medium BTU-Natural Gas	525	625	1997
Tristar Energy Ltd.	Diesel oil	105	110	1996
Sub-Total		**3327**	**4168**	
Some Proposed Private Power Projects				
Wak Power	n.a.	800	1200	1998
Enron Deve. Corp	Furnace Oil	760	–	1998
Fauji (FEBCO)	na	350	na	na
Fauji Foundation	Furnace Oil	350	475	1997
Spencer Gen.	Furnace Oil	330	413	–
Sub-Total		**2590**		
Some Private Power Projects under Negotiations				
Consolidated Electric Power Asia (First phase)	Indigenous Coal	1,320	1,600	1998
Consolidated Electric Power Asia (planned)	Indigenous Coal	5280	5500	2000
Hong-Pak United Power Generation	Indigenous Coal	1320 (2 x 660)	1670	na
BBI	Indigenous Coal	200	220	na
B.C Hydro Inter.	Hydro	1140	na	na
Synergics Inc.	Hydro	500	na	2000
Sub-Total		**9760**		
Grand Total		**15 677**		

*First unit of 323 MW
Source [10]

2.6. Energy Investments

In line with the Government's policy of increasing self-reliance energy supply, increasing emphasis has been placed on the development of this sector since the mid 1970s. Table 2.26 shows the total public sector investments and its sectoral shares in the 8 Five Year Plans. It may be noted that since 1978 (5th Five Year Plan) the energy sector has been claiming the largest share in the total public sector investments. The major public sector investments have been in the Power sector, which increased from Rs. 60 billions in the 6th plan to about Rs. 90 billion in the Seventh plan. This increasing emphasis on the power sector is a consequence of the basic strategy embodied in the Sixth and Seventh Plans which aimed at achieving the twin objectives of reduction in load shedding and rapid electrification of the rural areas. It may be noted that the share of fuels sector used to be low in the total public sector investments in the energy sector, however, there has been a significant increase in public sector investment in it too.

As already discussed, heavy emphasis has been placed on promotion of private sector activities through deregulation of the economy in order to transfer the bulk of the financial burden from the Government's budgetary resources to the private sector's own resources. It is envisaged that the share of private sector in total fixed investment during the Eighth Plan period will be 56% as compared to 41.2% and 44.3% during the Sixth and Seventh Plan periods, respectively. Similarly, within the energy sector, the share of private sector investments in the total energy sector investments is expected to increase to 53% in the current plan period from 21% and 12% during the Seventh and the Sixth Plans. Further, in addition to its participation in traditional areas related to production, transportation and distribution of oil, gas and coal, the private sector, for the first time, is being involved in power generation activities. To promote private sector investment in the power generation, a private sector fund of about US $600 million has been created to provide loans to potential investors up to 40% of the project cost. Resources for this fund have been contributed by the World Bank, USAID and other bilateral and multilateral agencies.

2.7. Environmental Aspects

In Pakistan, the energy system's contribution to environmental degradation is in three ways: (i) deterioration of air quality in the large cities, (ii) deforestation and (iii) soil degradation. Emissions of pollutants from transport vehicles and industries operating on fossil fuels are the major cause of air pollution. The other two impacts have their origin in the use of non-commercial fuels which are the mainstay of some 70% of the country's population living in rural areas as well as of urban poor. In the rural areas a large fraction of agricultural wastes and dung are also being burnt as fuel instead of being used as manure due to scarcity of fuelwood and inability of the masses to buy commercial fuels. This deprives the soil of vital nutrients, and damages the soil fertility of the already scarce agricultural land.

In the coming years, the air quality problems in large cities will exacerbate unless strong remedial measures such as: (i) switching to low sulphur and lead free fuels, (ii) introduction of mass transit systems, (iii) introduction of pollution control devices in industries operating in and around large cities are introduced. Additional energy related environmental concerns, which may arise in future, include those related to: (i) large scale production and use of indigenous coal resources, (ii) development of large storage hydro projects and (iii) provision of large-scale energy facilities.

Atmospheric emissions of CO_2, SO_2, NO_x and particulates due to energy use and power generation in Pakistan during 1992–93 are reported in Table 2.27. It may be noted that the present emissions of CO_2 in Pakistan (about 19 million tons of carbon) are about 0.3% of the global CO_2 emissions (some 6000 million tons of carbon). The present level of SO_2 emissions in Pakistan, though significant, are much lower than the emissions in some of the Asian countries, e.g. China, India and the Republic of Korea.

Table 2.26. Public Sector Investments under Five Year Plans

(Rs. Billion)

	I Plan (1955–1960)	II Plan (1960–1965)	III Plan (1965–1970)	Non-Plan Period (1970–1978)	V Plan (1978–1983)	VI Plan (1983–1988)	VII Plan (1988–1993)	VIII Plan (1993–1998)
Industry	0.74	0.48	0.79	11.29	25.40	12.916	9.0	1.9
Agriculture	0.46	0.91	1.38	6.49	14.86	17.302	15.6	5.7
Minerals	0.12	0.09	0.27	0.49	0.40	1.090	7.0	6.6
Transp. & Comm.	1.08	1.60	2.82	15.66	35.21	41.750	61.5	130.6
All Other Sectors	1.86	6.24	6.18	27.77	38.06	85.136	132.6	305.3
Energy	0.6	1.29	1.76	13.84	38.83	84.216	124.3	302.0
(Share of Total)	(12%)	(12%)	(13.3%)	(18.3%)	(25.4%	(34.7%)	(35.5%)	(40%)
Power	0.57	1.16	1.57	10.88	28.12	60.619	90.2	212.7
Fuels	0.03	0.13	0.19	2.96	10.71	23.597	34.1	89.4
Total	**4.86**	**10.61**	**13.20**	**75.54**	**152.76**	**242.41**	**350.0**	**752.1**

Source: [10]

Pakistan fully shares the world-wide concern for global warming resulting from CO_2 emissions due to continued heavy reliance on fossil fuels. However, the country's immediate concern is to provide adequate energy to meet its socioeconomic development requirements, and to achieve a high level of energy self-sufficiency. For this reason, the country will have to follow a supply strategy involving an appropriate mix of hydropower, fossil fuels and nuclear energy, making maximum feasible use of indigenous resources. But at the same time, to check the expected increase in emissions from energy use and conversion, Pakistan has made plans to improve the energy efficiency levels rather than applying the harsh methods, such as CO_2 tax, to cut down the emissions.

Table 2.27. Atmospheric Emissions due to Energy Use (1992–93)

Sector	CO_2 (Million Ton)	SO_2 (000 Ton)	NO_x (000 Ton)	Particulates (000 Ton)
Agriculture	5.4	33.3	116.4	3.9
Household/Service	7.2	3.2	6.2	0.7
Industry	21.8	437.5	45.8	302.1
Transport	16.0	70.5	189.4	10.6
Power	19.5	199.2	73.0	5.2
Total	69.8	743.7	430.8	322.5

Source: [23]

As for other energy-related environmental issues, the Government of Pakistan generally follows the environmental guidelines laid down by the World Bank and the Asian Development Bank, while implementing large-scale energy projects. However, as yet, the country does not have an explicitly stated, generic environmental policy. A National Conservation Strategy has been formulated by the Ministry of Environment & Urban Affairs, which recommends a number of policies and measures on environmental issues in various economic and social sectors. It also proposes to make all the planning agencies directly responsible for the maintenance of ecological systems and processes, and for the sustainable use of natural resources.

Prior to 1980, environmental issues did not receive much attention in Pakistan. It was only in 1983 when the Environmental Protection Ordinance was approved which allowed for the creation of Environmental Protection Agencies at federal and provincial levels. But necessary legislation enabling these agencies to enforce environmental standards were not promulgated until recently.

The practice so far in Pakistan has been to select various commercially available technologies for power generation purely on the basis of cost-economics keeping in view the availability of corresponding primary fuels. Since early 1980s, the World Bank Guidelines for Developing Countries for environmental protection have also been followed, while approving different power projects. As a result, for example, a proposed project comprising 2 x 350 MW steam plant based on indigenous coal from the Lakhra field was abandoned because it could not meet the requisite environmental standards in the absence of FGD, while with FGD it was unable to compete economically with the available alternatives based on imported coal and oil.

Very recently, the Government has established the National Environmental Quality Standards relating to municipal and liquid industrial effluents, industrial gaseous emissions and motor vehicle exhaust and noise [24]. Since the power sector has been declared an industry, the National Environmental Quality Standards related to industrial units would also be applicable to power projects. In the case of new projects, these Standards are applicable from 1st July 1994, while for existing plants, these would be enforced from 1st July 1996.

2.8. Policies and Plans to Promote Energy Efficiency

Various agencies are engaged in activities related to energy conservation and improvement of energy efficiency in all sectors of the economy. The National Energy Conservation Centre (ENERCON), established in 1986, is responsible for planning and coordination of activities related to energy conservation and improvement of energy efficiency in all sectors of the national economy. ENERCON has identified the potential of energy savings in various sectors and is implementing a number of programmes for realization of this potential with the help of international donor agencies. These programmes include tune up/ retrofit of boilers/ furnaces in industries, auto tuning in the road transport sector, retrofit and redesign of tubewells in the agriculture sector and efficiency improvement in commercial and domestic lighting. Recently, the Center has also involved private sector in its efforts. A National Energy Conservation Buildings Code, which includes recommended specifications for both the design of buildings and the use of equipment to heat, cool and light the buildings, has been approved by the Government for adoption on a voluntary basis.

In the power sector, WAPDA has been working on reducing transmission and distribution losses. The utility has reduced the system losses from 29% in 1984–85 to 24% in 1994 as discussed in section 2.5.7. The Hydrocarbon Development Institute of Pakistan (HDIP) has been promoting compressed natural gas (CNG) consumption in private transportation to substitute diesel and gasoline use. For the non-commercial energy products, the Pakistan Council for Appropriate Technology (PCAT) has been promoting new design of wood stoves. These stoves are 30% more efficient than the traditional stoves and are also smoke free (The Pakistan Council for Appropriate Technology (PCAT) and Gesellschaft für Technische Zusammenarbeit (GTZ) of Germany have done considerable development and promotional work in Pakistan in this field).

Public education is an important part of energy conservation and energy efficiency programmes of all the organizations. Mass media has been used to increase public awareness and workshops/ seminars are being arranged to train engineers, technicians, managers, etc., to implement energy conservation programmes.

At present, the Government of Pakistan is implementing its 8th Five-Year Plan. For the energy sector, the plan aims to promote energy demand management, which includes improvement in energy efficiency. The policy measures identified for this purpose are as follows:

(1) Review and rationalization of the structure of duties/taxes to promote procurement of energy conservation equipment and materials.

(2) Policy package for promoting the use of high efficiency appliances/vehicles and building materials, mandatory energy efficiency labeling and setting up standards and codes wherever feasible.

(3) Introduction of mass transit systems for major cities, improvement in railways.

(4) Recovery of cost of service from all categories of consumers except low-income consumers.

(5) Reduction of losses in transmission and distribution of electricity.

(6) Rationalization of energy prices to discourage wasteful use of energy in all sectors of the economy.

Chapter 3

DEFINITION OF SCENARIOS OF SOCIO-ECONOMIC DEVELOPMENT AND OF ENERGY DEMAND AND SUPPLY

3.1. Introduction

The primary objective of the study is to identify the optimum share of nuclear power in the future electricity supply mix of Pakistan. Since the development of nuclear power can only be implemented gradually over a long period, the main issue of the study can be analysed by considering a long planning horizon. Further, in view of the long lead time for planning and construction of power projects and long operation lives of power plants, it is desirable to consider a planning horizon of two to three decades. However, such a long planning horizon introduces to the analysis a number of uncertainties, for example, future electricity demand, primary energy supplies from indigenous sources, fuel import possibilities, development in electricity generation technologies, environmental concerns, financial resource availability, etc.

There is no unique analytical methodology available to handle all these uncertainties. The most suitable approach, generally adopted, is the development of scenarios with consistent assumptions for future evolution of important driving parameters. In the context of energy and electricity planning, the important parameters are: (i) demography, (ii) structure and growth of economy, (iii) development of indigenous energy resources and their future supply potential, (iv) prices of internationally traded fuels, (v) developments in electricity generation and environmental control technologies and (vi) developments in regional or international environmental frameworks related to emissions of acid rain precursors or greenhouse gases, etc.

Generally only a few scenarios are developed based on the judgement of experts of a given field, covering plausible range for future evolution of the main driving parameters. A limited number of scenarios facilitates the comprehension of the spirit of the scenario and the differences among scenarios. This chapter describes the main features of the scenarios of socio-economic development and of energy demand and supply analysed in the study.

3.2. Demography

The population growth rate in Pakistan has been around 3% per annum for the last 10 years. The government is conscious about the rapidly growing population and has been pursuing an intensive population welfare program aimed at curtailing population growth. The current official targets for the Perspective Plan (1993–2008) envisage reduction in population growth from 2.9% now to 2.1% by the year 2007–08 [8]. For the present study, this target has been adopted as the basis of the demographic scenario. Since the study period extends to 2022–23, the population beyond 2007–08 has been projected in line with the World Bank's estimates for population growth in Pakistan during the period 2000–2025 [25].

Only one scenario of population growth has been considered in the present study. Other demographic parameters e.g. urban–rural split and employment rate have been linked with economic growth scenarios, since the level of economic growth is expected to have significant impact on these parameters. Corresponding to one of the economic scenarios (Planning Target Growth Scenario) the projections of various growth demographic parameters are reported in Table 3.1.

Table 3.1. Projections of Demographic Parameters (Planning Target Growth Scenario)

Year	1992–93	1997–98	2002–03	2007–08	2012–13	2017–18	2022–23
Total Population (Million)	120 83	138.92	158.64	177.74	196.72	215.61	234.57
Growth Rate (%)	2.83%	2.69%	2.30%	2.05%	1.85%	1.70%	
Rural Population (Million)	82.77	92.38	102.48	111.62	120.40	128.98	137.46
Growth Rate (%)	2.22%	2.10%	1.72%	1.52%	1.39%	1 28%	
Share (%)	68.50%	66.50%	64.60%	62.80%	61.20%	59.82%	58.60%
Urban Population (Million)	38.06	46.54	56.16	66.12	76.33	86.63	97.11
Growth Rate (%)	4.10%	3.83%	3 32%	2.91%	2.56%	2.31%	
Share (%)	31.50%	33.50%	35.40%	37.20%	38.80%	40.18%	41.40%
Population of Large Cities (Million)	23.56	29.87	37.12	44.97	53.71	62.76	72.74
Share in Total Population (%)	19.50%	21.50%	23.40%	25.30%	27.30%	29.11%	31.01%
Persons per Household	7.19	7.09	6.99	6.89	6.79	6 70	6.60
Persons per Household (Rural)	7.244	7.156	7.068	6.982	6.896	6.812	6.729
Persons per Household (Urban)	7.075	6.962	6.851	6.743	6.635	6.530	6.426
Rural Households (Million)	11.43	12.91	14.50	15.99	17.46	18.93	20.43
Growth Rate (%)	2.47%	2.35%	1.97%	1.77%	1.64%	1.53%	
Urban Households (Million)	5.38	6.68	8.20	9.81	11.50	13.27	15.11
Growth Rate (%)	4.44%	4.16%	3.65%	3.24%	2.89%	2.64%	
Total Households (Million)	16.81	19.60	22.70	25.79	28.96	32.20	35.54
Working Age Population (Million)	79.23	92.30	107.41	123.50	141.02	158.01	175.31
Growth Rate (%)	3.10%	3.08%	2.83%	2.69%	2.30%	2.10%	
Share (%)	65.57%	66.44%	67.71%	69.48%	71.69%	73.28%	74.74%
Potential Labour Force Actually Working (Million)	31.98	37.83	44.51	51.98	60.26	69.52	79.80
Growth Rate (%)	3.42%	3.31%	3.15%	3.00%	2.90%	2.80%	
Share (%)	40.36%	40.99%	41.44%	42.09%	42.73%	44.00%	45.52%

The projected urban–rural split has been worked out in line with historical trends and the 8th Five Year Plan's perspective on urbanization. This extrapolation indicates that even by the year 2023 the majority of the population (58.6%) will still be living in rural areas. The share of population living in large cities has been estimated in view of past trends. Household sizes in the rural and urban areas are also essentially extrapolations of the past trends. Potential labour force is projected in line with overall population growth. The labour force actually employed has been projected till the year 2008 on the basis of official targets for creation of employment, while for the remaining period this parameter has been extrapolated.

3.3. Macro-economy

The future developments on the international economic scene will have considerable impacts on the prospects of economic growth of developing countries. Historical trends have shown that higher economic growth in developed countries helps achieving higher growth in the developing economies. The international trade and capital flows play a major role in boosting economic growth in the developing countries. The inflation and interest rates in industrialised countries also affect the performance in developing countries. As a result of the conclusion of General Agreement on Trade and Tariff (GATT) and establishment of World Trade Organisation (WTO), it is hoped that the volume of international trade will increase considerably and both, the developing and developed countries, will benefit from competitive and free trade environment. Further, the domestic polices in developing countries are being made more conducive to capital-in-flow. Explicit incorporation of the effect of all these parameters in the study scenarios would require use of macro-economic models which is beyond the scope of this study. However, based on recent estimates by the World Bank [26] and other organisations, economic development scenarios for Pakistan can be developed which would cover a wide range of possibilities.

The World Bank [26] has estimated that the world economy as a whole will grow at about 3.2% p.a. during 1994 and 2003. The OECD countries have been projected to grow at 2.7% p.a. while the growth in developing countries as a group has been estimated as 4.8% p.a. As in the past, there will be a wide variation in the economic growth in different developing countries. The economic growth in South Asia has been estimated at 5.3% p.a. In view of many uncertainties, an overall lower growth (3.6% p.a.) in the developing countries has been considered by the World Bank as another possibility. Corresponding to that, the economic growth in the South Asia has been projected as 4.2% p.a. Another recent study [27] has projected economic growth for the next 20 years period as: for OECD: 1.9–2.6% p.a.; for developing countries: 4.3–6.2% p.a. and for South Asia: 4.1–5.8% p.a.

Keeping in view these perspectives and the perspectives of the Planning Commission, three scenarios of economic growth in Pakistan, viz. (a) Planning Target Growth Scenario, (b) Optimistic Growth Scenario, and (c) Constrained Growth Scenario have been developed.

The Planning Target Growth Scenario reflects essentially the perspective of the Planning Commission and incorporates official targets. The Optimistic Growth Scenario corresponds to the high world economic growth cases of the World Bank and OECD studies, while the Constrained Growth Scenario corresponds to low economic growth cases of these studies. The overall economic growth in these macro-economic scenarios have been assumed as: Planning Target Growth Scenario 7.0% p.a., Optimistic Growth Scenario 8.5% p.a., Constrained Growth Scenario 5.7% p.a. The quantitative details are given in the following paragraphs.

Table 3.2. Eighth Five Year Plan (1993–1998) and Perspective Plan (1993–2008) Economic Targets

(1992–93 Billion Rs.)

1. Sectoral Growth Targets of The Eighth Five Year Plan (93–98)			
	1992–1993 Bench Mark	**1997–1998**	**Annual Growth Rates(%)**
1. Agriculture	301.9	382.8	4.9
Major Crops	(127.1)	(156.7)	4.3
Minor Crops	(49.5)	(60.3)	4.0
Livestock	(113.9)	(152.7)	6.0
Fishing	(7.8)	(9.0)	2.9
Forestry	(3.6)	(4.1)	2.8
2. Mining & Quarrying	8.5	14.6	11.4
3. Construction	54.4	79.2	7.8
4. Manufacturing	218.5	349.9	9.9
Large Scale	(152.1)	(250.6)	10.5
Small Scale	(66.3)	(99.3)	8.4
5. Electricity & Gas Distribution	41.9	62.2	8.2
6. Services	606.6	838.6	6.7
GDP (at Factor Cost)	1231.8	1727.3	7.0
2. Major Economic Indicators & Population: Perspective Plan (1993–2008)			
	1993–1998	**1998–2003**	**2003–2008**
GDP & Population Growth Rates			
–GDP (% p.a.)	7.0	7.0	7.0
– Population (% p.a.)	2.85	2.69	2.3
– Per Capita Income (% p.a.)	4.1	4.2	4.3
	1997–1998	**2002–2003**	**2007–2008**
Composition of GDP (% Shares)			
– Agriculture	22.1	19.6	17.1
– Manufacturing	20.3	22.7	25.1
– Others	57.6	57.7	57.8

Source: [8]

3.3.1. Planning Target Growth Scenario

This scenario has been developed as a reference scenario (see Table 3.2) and it essentially reflects the official targets for the 8th Five Year Plan (1993–98) and Perspective Plan (1993–2008). Table 3.3 gives the growth rates of various sectors of the economy as projected for this scenario. In this case the growth rates have been assumed in line with the 8th Five Year Plan

(1993–98) and Perspective Plan (1993–2008) targets, and by extending similar trends till the year 2022–23. The Agriculture sector has registered a growth of 3.4 to 5.5% p.a. during the last 30 years. The future growth rate for this sector has been assumed as 4.9% p.a. during 1993–98, declining gradually to 4.1% p.a. by the year 2008 and then to remain constant until the year 2023, so that the agriculture GDP per capita during the period increases by about 80% reflecting improvement in availability of food. The official target for growth in the Manufacturing sector is 9.9% p.a. during the 8th Plan, 9.4% p.a. and 9.2% p.a. during the 9th and 10th Five Year Plans respectively. Thereafter, it is assumed that in line with the projected trend the growth rate of this sector would further decline gradually to 8.6% p.a. by 2023. Table 3.4 gives the shares of various sectors in total GDP.

Table 3.3. Projected Growth Rates of Gross Domestic Product (at Constant Factor Cost of 1992–93)

[% p.a.]

Planning Target Growth Scenario	**1993 – 1998**	**1998 – 2003**	**2003 – 2008**	**2008 – 2013**	**2013 – 2018**	**2018 – 2023**
Agriculture	4.90	4.50	4.10	4.10	4.10	4.10
Mining	11.40	10.00	9.00	9.00	9.00	9.00
Manufacturing	9.90	9.40	9.20	9.00	8.80	8.60
Building & Construction	7.80	7.00	7.00	7.00	7.00	7.00
Energy	8.20	8.50	8.50	8.50	8.50	8.50
Services	6.70	6.90	6.93	6.77	6.65	6.55
Total GDP	6.98	6.99	7.00	7.00	7.00	7.00
Optimistic Growth Scenario						
Agriculture	4.90	5.25	5.50	5.40	5.20	5.00
Mining	11.40	11.00	10.00	10.00	10.00	10.00
Manufacturing	9.90	11.00	12.50	12.00	11.50	11.00
Building & Construction	7.80	7.70	7.50	7.50	7.50	7.50
Energy	8.20	8.75	9.00	9.00	9.00	9.00
Services	6.70	7.85	8.70	8.50	8.50	8.50
Total GDP	6.98	8.00	9.00	8.99	9.02	9.00
Constrained Growth Scenario						
Agriculture	4.90	4.30	4.00	4.00	4.00	4.00
Mining	11.40	9.00	8.50	8.00	8.00	8.00
Manufacturing	9.90	7.50	6.70	6.30	6.00	5.50
Building & Construction	7.80	6.50	5.50	5.00	5.00	5.00
Energy	8.20	7.50	7.25	7.00	7.00	7.00
Services	6.70	5.95	5.40	5.25	5.15	4.80
Total GDP	6.98	6.01	5.50	5.34	5.26	5.00

Table 3.4. Projected Sectoral Shares of Gross Domestic Product (at Constant Factor Cost of 1992–93)

[Percentage]

Planning Target Growth Scenario	1992–93	1997–98	2002–03	2007–08	2012–13	2017–18	2022–23
Agriculture	24.81	22.49	19.99	17.43	15.19	13.24	11.54
Mining	0.62	0.75	0.87	0.95	1.04	1.15	1.26
Manufacturing	17.29	19.78	22.11	24.48	26.86	29.20	31.45
Building & Construction	4.15	4.31	4.31	4.31	4.31	4.31	4.31
Energy	3.23	3.42	3.67	3.93	4.22	4.52	4.85
Services	49.90	49.25	49.05	48.89	48.37	47.58	46.59
Total GDP	100	100	100	100	100	100	100
Total GDP (Billion Rs.)	1200.46	1682.31	2358.16	3307.14	4638.03	6505.47	9123.76
GDP/Capita (Rs./Capita)	9935	12 110	14 865	18 606	23 576	30 173	38 896
Population (Million)	120.83	138.923	158.641	177.743	196.724	215.607	234.568
Optimistic Growth Scenario							
Agriculture	24.81	22.49	19.76	16.79	14.20	11.88	9.86
Mining	0.62	0.75	0.87	0.91	0.95	0.99	1.04
Manufacturing	17.29	19.78	22.68	26.57	30.44	34.08	37.32
Building & Construction	4.15	4.31	4.25	3.97	3.70	3.45	3.22
Energy	3.23	3.42	3.54	3.54	3.54	3.54	3.54
Services	49.90	49.25	48.90	48.23	47.16	46.06	45.02
Total GDP	100	100	100	100	100	100	100
Total GDP (Billion Rs.)	1200.46	1682.31	2472.22	3803.60	5849.28	9006.26	13 855.24
GDP/Capita (Rs./Capita)	9935	12 110	15 584	21 399	29 733	41 772	59 067
Constrained Growth Scenario							
Agriculture	24.81	22.49	20.73	19.30	18.10	17.04	16.25
Mining	0.62	0.75	0.87	1.00	1.13	1.29	1.48
Manufacturing	17.29	19.78	21.21	22.44	23.48	24.32	24.90
Building & Construction	4.15	4.31	4.41	4.41	4.34	4.29	4.29
Energy	3.23	3.42	3.67	3.98	4.30	4.67	5.13
Services	49.90	49.25	49.11	48.87	48.65	48.40	47.95
Total GDP	100	100	100	100	100	100	100
Total GDP (Billion Rs.)	1200.46	1682.31	2252.26	2944.03	3819.49	4935.16	6297.75
GDP/Capita (Rs./Capita)	9935	12 110	14 197	16 563	19 415	22 890	26 848

The Manufacturing sector consists of large scale industries and small scale industries. The large scale industries can be further subdivided in to basic materials, machinery and equipment and consumer goods industries. Table 3.5 gives the composition of basic materials, machinery and equipment and consumer goods industries along with their shares in the manufacturing value added, for 1987–88. The historical shares of small scale, basic materials, machinery and equipment and consumer goods industries in the manufacturing sector value added are shown in Fig. 3.1. It may be noted that consumer goods industries have the largest share and machinery and equipment industries have the smallest share. Further the share of small scale industries has been slightly increasing during the recent years. However, due to the high growth rate envisaged for the Manufacturing sector as a whole the share of small scale industries has been projected to decline. Within the Manufacturing sector, the growth rate of small scale industries has been projected to decline gradually from 8.4% p.a. during the 8th Plan to 6.5% p.a. by the terminal plan period while the large scale industries has been projected to decline from 10.5% during the 8th Plan and declining gradually to 9.2% p.a. by the terminal period.

As for the breakdown of the large scale industries into basic materials, machinery & equipment and consumer goods, the historical trends in Pakistan and other developing countries [10, 25 and 28] have been kept in view, in addition to the official targets for the 8th Plan for the production of various major industries. The growth rate of basic materials industries has been assumed to increase initially and then to decline gradually. For the 8th Five Year Plan period (1993–98) the growth in this sub-sector has been assumed as 10.5% p.a., increasing to 10.8% p.a. in the next five year period and then decreasing gradually to 9.2% p.a. by the last five year period (see Tables 3.6 and 3.7). The machinery & equipment industries have been assumed to grow at even higher rates: 15.8% p.a. during 1993–98, 14.8% p.a. in 1998–2003 and further declining in the subsequent periods reaching to 11% p.a. by the terminal period. For the consumer goods industries, the growth rates have been adjusted in such a way that the share of this subsector declines from the present value of 37.3% to 30.7% by the terminal year. The growth rate in this subsector declines from 9.5% p.a. for the 8th Five Year Plan period to 7.8% by the end of planning horizon.

Table 3.5. Shares of Various Industries in the Value Added of Large Scale Manufacturing Industries (1987–88)

PSIC Code @	Industries	Share [%]	Share [%]
	Basic Material Industries		
34	Paper and Paper Products, Printing and Publishing	5.8	
35	Chemicals, Petroleum Refining, Petroleum & Coal Products, Rubber and Plastic Products	52.2	
36	Non–metallic Mineral Products (except petroleum and coal)	23.7	
37	Iron & Steel Basic Industries	18.3	
	Total	100.0	35.6
	Machinery and Equipment Industries		
38	Fabricated Metal Product and Equipment	100.0	10.0
	Consumer Goods Industries		
31	Food, Beverages and Tobacco	51.3	
32	Textile, Wearing Apparels and Leather	40.1	
33	Wood, Wood Products including Furniture	0.9	
39	Other Manufacturing Industries and Handicraft	7.8	
	Total	100.0	54.4
	Total large Scale Manufacturing		100.0

@ Pakistan Standard Industrial Classification Code

Source : [10]

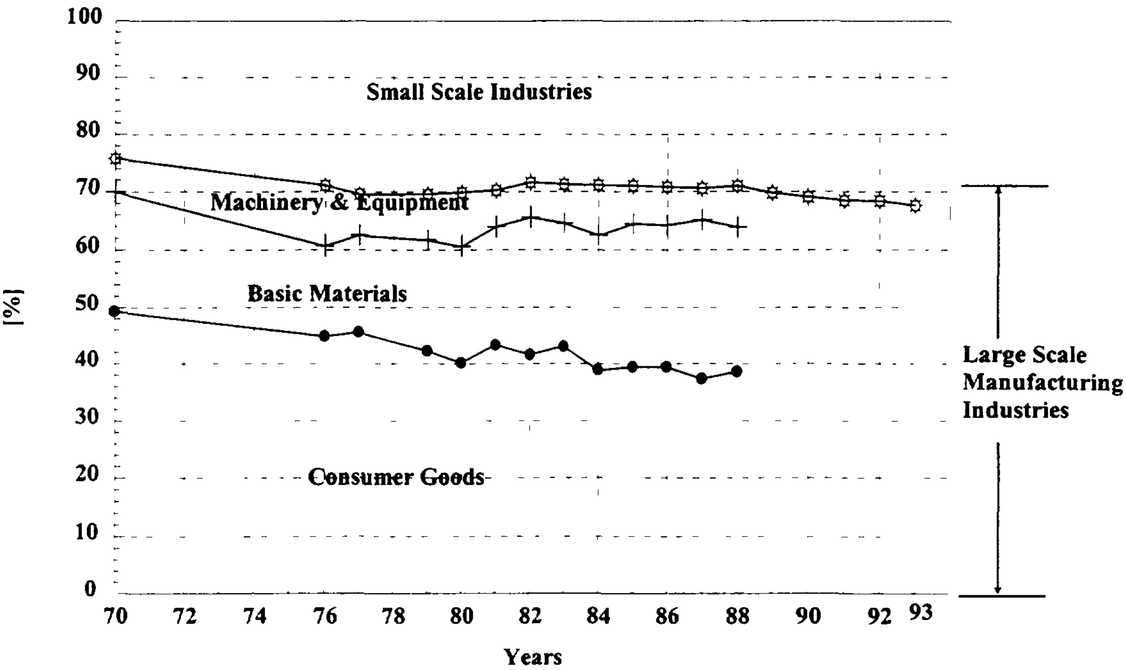


FIG. 3.1. Share of Consumer Goods, Basic Materials, Machinery & Equipment and Small Scale Industries in Manufacturing Sector Value Added

Note: Breakdown of value added of Large Scale Manufacturing Industries into sub components is not available after 1987–88.

Source: Based on [10]

The Service sector has been assumed to grow at more or less the same growth as the overall GDP. The contribution of the remaining sectors in the total GDP is relatively very small. Their growth rates have also been assumed in line with the targets for the 8th Five Year Plan. The per capita income (in constant rupees of 1993) in this scenario would increase from Rs. 9,935 in 1992–93 to Rs 18,606 by 2007–08 and to Rs. 38,896 by 2022–23.

3.3.2. Optimistic Growth Scenario

As an alternative to the Planning Target Growth Scenario, this scenario has been developed to explore the implications for the energy sector of a higher economic growth which may be achieved if the international economic environment is favourable and the domestic economic policies are restructured to gain maximum advantage. Some of the fast developing economies in Asia–Pacific region, e.g. South Korea, China, Thailand, have experienced even more than 10% p.a. economic growth for some years in the recent past. In Pakistan also, some development economists believe that significantly higher economic growth than that adopted for the 8th Five Year Plan, could be attained. As such, this optimistic scenario has been developed to cover an extreme possibility. The overall economy in this scenario has been assumed to grow at 7% p.a. in the 8th Five Year Plan period, gradually attaining a growth rate of about 9% p.a. by 2008 and then to remain constant thereafter. The main contributor to such a high growth would be the manufacturing sector with growth rates of 10–12% per annum during the 1992–93 to

2022–23 period. The growth rate for all other sectors have also been assumed somewhat higher than those for Reference scenario. The per capita income (in constant rupees of 1993) in this scenario would increase from Rs. 9,935 in 1992–93 to Rs. 21,399 by 2007–08 and to Rs. 59,067 by 2022–23.

Table 3.6. Growth of Manufacturing Industries in the Three Scenarios

[% p.a.]

	1993 – 1998	1998 – 2003	2003 – 2008	2008 – 2013	2013 – 2018	2018 – 2023
Reference Scenario						
Total Manufacturing	9.90	9.40	9.20	9.00	8.80	8.60
Basic Materials	10.53	10.85	10.20	9.66	9.41	9.22
Mach. & Equipment	15.80	14.81	13.50	12.52	11.76	11.02
Consumer Goods	9.50	8.61	8.50	8.27	8.01	7.77
Small Scale Industry	8.40	7.19	7.00	7.02	6.76	6.52
Optimistic Growth Scenario						
Total Manufacturing	9.90	11.01	12.50	12.00	11.49	11.00
Basic Materials	10.53	12.80	14.35	13.45	12.50	11.50
Mach. & Equipment	15.80	16.90	17.70	16.25	14.75	13.60
Consumer Goods	9.50	10.01	11.40	10.60	10.00	9.70
Small Scale Industry	8.40	8.55	9.25	9.00	9.00	9.00
Constrained Growth Scenario						
Total Manufacturing	9.90	7.50	6.70	6.30	6.00	5.49
Basic Materials	10.53	8.45	7.48	6.74	6.18	5.51
Mach. & Equipment	15.80	11.80	10.09	8.89	8.23	7.26
Consumer Goods	9.50	7.00	6.28	5.89	5.53	4.96
Small Scale Industry	8.40	5.80	5.00	5.00	5.03	4.96

3.3.3. Constrained Growth Scenario

This scenario has been developed as another alternative to the Planning Target Growth Scenario with the underlying assumption that the international economic environment will not improve significantly and the economic growth in the developed countries would remain depressed, resulting in less demand for the produce of developing countries and thereby having a depressing effect on their economies. The overall economic growth in this scenario has been assumed to decrease gradually from the 7% p.a. target for the 8th Five Year Plan to 5.5% during 2003–08 and to about 5% during 2018–23. The per capita income (in constant terms) in the year 2022–23 would be 2.7 times the 1992–93 value, i.e. reaching a level of Rs. 26,848, which is about 70% of the value for the Planning Target Growth Scenario.

Table 3.7. Structure of Manufacturing Industries in The Three Scenarios

[% Shares]

	1992–1993	1997–1998	2002–2003	2007–2008	2012–2013	2017–2018	2022–2023
Reference Scenario							
Basic Materials	24.4	25.1	26.8	28.1	28.9	29.8	30.6
Mach. & Equipment	6.9	8.9	11.4	13.8	16.2	18.5	20.6
Consumer Goods	37.3	36.6	35.3	34.2	33.1	31.9	30.7
Small Scale Industry	31.4	29.4	26.5	23.9	21.8	19.9	18.0
Optimistic Growth Scenario							
Basic Materials	24.4	25.1	27.2	29.5	31.5	32.9	33.7
Mach. & Equipment	6.9	8.9	11.6	14.5	17.5	20.2	22.6
Consumer Goods	37.3	36.6	35.0	33.3	31.3	29.2	27.6
Small Scale Industry	31.4	29.4	26.2	22.7	19.8	17.7	16.1
Constrained Growth Scenario							
Basic Materials	24.4	25.1	26.2	27.2	27.8	28.0	28.0
Mach. & Equipment	6.9	8.9	10.9	12.7	14.3	15.9	17.3
Consumer Goods	37.3	36.6	35.8	35.1	34.4	33.7	32.8
Small Scale Industry	31.4	29.4	27.1	25.0	23.5	22.4	21.9

3.4. Indigenous Resources Development

The following paragraphs provide a summary of the main assumptions and the assumed production or exploitation levels of indigenous energy resources.

Oil & Gas: As already discussed in section 2.4, Pakistan has fairly good reserves of natural gas but very meagre reserves of oil. However, undiscovered resources of oil and gas are estimated to be very promising. Intensive exploration has not been possible so far due to lack of financial resources and the perception among some exploration companies that the sedimentary basins of Pakistan are more gas prone and exploration for gas was not considered as attractive as for oil. Since early 1990s, through successive petroleum policies, a number of incentives have been provided for exploration of both oil and gas. In the light of these policies it is expected that oil and gas exploration activity will increase significantly in future compared to past experience. It has been assumed that the exploration activity will increase from the 8th Five Year Plan (1993–98) target of 142 wells to 197 wells during 9th Five Year Plan (2003–08) period and to 285 wells during the 13th Five Year Plan (2018–23) period. These projections are in line with the "Base Case" considered by the Energy Wing and DGPC [29, 30]. Based on the scenario of exploratory effort, projected quantities of additional oil and gas reserves discovered and production profiles of oil and gas have been estimated using a petroleum model developed by ASAG and Hydrocarbon Development Institute of Pakistan (HDIP). The model uses geological parameters such as resource potential, success ratio, size of discoveries and probability of oil or gas, etc. to determine the addition to reserves and maximum production profiles for oil and gas.

The details of this methodology and main input parameters are described in Appendix E. The resulting projections of future oil and gas production are reported in Table 3.8.

Table 3.8. Scenario of Exploratory Effort for Oil and Gas and Projected Production Profiles of Oil & Gas

	1993 – 1998	1998 – 2003	2003 – 2008	2008 – 2013	2013 – 2018	2018 – 2023	
Exploration Wells	142*	170	197	230	259	285	
Oil Reserves Discovered (MTOE)	27.2	31.5	32.9	56.3	57.7	65.7	
Gas Reserves Discovered (MTOE)	107.0	109.3	211.8	120.4	178.4	191.8	
.							
	1992–93	**1997–98**	**2002–03**	**2007–08**	**2012–13**	**2017–18**	**2022–23**
Projected Production of Oil and Gas							
Oil (MTOE)	2.9	4.6	5.3	5.9	7.7	9.5	11.5
Gas (MTOE)	12.4	16.1	24.2	32.7	39.9	43.3	45.1

* Eighth Plan Target

Coal: Among the various coal fields in Pakistan, only Lakhra has sizeable proven reserves to support some 1000–1500 MW coal fired power capacity. However, since the sulphur content of Lakhra coal is very high (about 5.5%) some SO_2 control technology will have to be used for utilization of this coal. Fluedised bed combustion (FBC) technology is already being tried for use of Lakhra coal. It has, therefore, been assumed that 1000 MW coal fired power plants of FBC type will be built on Lakhra coal. Further, in view of the large size of Thar coal field, it has been assumed that some 10–15 GW coal fired capacity of conventional steam plants can be based on Thar coal in the next 30 years period. However, in view of the long lead times required for investigations and field development, it has been assumed that a part of future coal fired capacity will have to be based initially on imported coal which, if technically feasible, will be switched to indigenous Thar coal later on. As the identified resources of Thar coal are very large, it has been assumed that the coal production will be primarily determined by the demand for this coal by the power sector. As for non–power sector, use of coal is only envisaged for bricks kilns. It has been assumed that this non-power sector demand, which is expected to grow at the rate of the construction sector, will all be met from various coal fields in the country. The demand for coking coal will all be met from imports.

Hydro: As already mentioned, some 4,825 MW hydro capacity has been developed while another 1,635 MW (Ghazi Barotha and Chashma) is under construction. Future development of hydro power is constrained by a combination of technical, economic, environmental and socio-political factors. Construction of two large hydro projects, (Kalabagh, 2780 MW and Basha, 3360 MW) with a total installed capacity of about 6000 MW is under consideration/being planned. In addition, further extension of Tarbela and construction of Kohala run-of-river are also being planned. Assuming all these hydro projects will materialize, it is expected that the hydro capacity by the end of planning horizon will reach to a level of about 14500 MW.

3.5. Energy Imports

As mentioned in Section 2.3, Pakistan is dependent on imports for about one-third of its commercial energy requirements. At present, crude oil and oil products (including LPG) are imported for meeting about three-quarters of oil requirements besides importing coking coal for steel industry. The size of the country's indigenous energy resources will entail continuation of import of fuels for meeting future energy requirements. Besides, import of gas from neighbouring countries is also being planned for future. In this regard the Government has signed three memoranda of understandings with the governments of Qatar, Islamic Republic of Iran and Turkemanistan [10]. The capacity of gas pipelines from Qatar (of 1700 km length) and Iran (of 1600 km length) are expected to be about 1.6 billion ft^3/day (45 million m^3/day) each and the investment cost of these pipelines are estimated to be about US \$4 billion and US \$3 billion respectively. The capacity and investment cost of gas pipeline from Turkemanistan (of 1400 km length) has not been estimated yet but are believed to be similar to the gas pipeline project of the Islamic Republic of Iran. The import of gas from Turkemanistan is very uncertain due to the fact that the pipeline has to pass through Afghanistan, which at present is politically unstable. All these projects have uncertain investment costs and the gas purchase prices for these projects have yet to be negotiated.

In view of the economic uncertainties for all these projects and political risks involved, two cases of gas import have been considered. In the first case it is assumed that all the three gas pipeline projects will materialise. The Pakistan–Islamic Republic of Iran project, which is considered to be at the most advanced planning stage, has been assumed to become operational in 2001, while the Pakistan–Qatar and Pakistan–Turkemanistan projects have been assumed to be implemented sequentially after a gap of few years. In the second case no import of gas has been considered in order to estimate the extent of oil imports necessary to meet the future primary energy requirements.

As for import of coal, it has been assumed that all requirements of coking coal will be met from import. In addition, steam coal will be imported for fuelling coal fired power plants to be located on coastal areas. In view of environmental concerns, it has been assumed that a maximum of 7000 to 10 000 MW coal based power capacity can be built near coast line because of limitations in the number of appropriate sites. A part of this capacity will be based on imported coal, which if technically feasible may latter be switched to indigenous coal from the Thar field.

No limit has been assumed for oil imports which are assumed to fill the gap left by the supplies from indigenous resources and the imports of gas and coal. Pakistan is also planning to import electricity from Tajikistan for which an agreement has already been signed between WAPDA and Tajikistan, but due to the civil war in Afghanistan, the en route country for transmission lines, the commissioning schedule of this project is very uncertain and this project has not been considered in the present study.

3.6. Energy Prices

International prices of crude oil after experiencing large variations during the 1973 to 1986 period have shown relative stability in recent years (see Fig. 3.2.). Similarly the international prices of steam coal have also shown relative stability since 1985 (see Table 3.9). Projection of prices of internationally traded fuels, i.e. crude oil, steam coal etc., for planning studies covering a period of two to three decades is an essential component of such studies. However, considering the large number of factors determining the change of international fuel prices (e.g. economic growth of various regions of the world determining the increase in energy demand; availability of alternate fuels and technologies, say, natural gas, hydro and nuclear power; technological developments in energy supply and use; global environmental concerns and political factors) a reliable and robust projection can hardly be attempted.

Nevertheless, various international agencies have made projections of internationally traded fuels, which vary considerably showing large uncertainty of these projections. For example, the fuel price projections recently reported by IIASA International Energy Polls vary from constant fuel prices to a fuel price escalation of 3.2% p.a. in real terms from 1990 to 2020. The median value of these polls are often used for planning purposes, which correspond to crude oil prices to escalate at the rate of 2.1% p.a. for the period 1990–2020 [34]. The recent OECD study "World Energy Outlook" has adopted two projections of crude oil prices: i) prices to remain constant in real terms at a rate of US $ 18/bbl for the period 1993–2010 and ii) to increase the prices to a level of US $ 28/bbl up to 2005 at an average growth rate of 5.1% p.a. and to remain constant afterwards till the year 2010 [27]. The recent projections of OPEC assume that during the period 1994–2000, the price of oil, in real terms, will remain constant and after the year 2000 will increase at the rate of 3.5% p.a. [35].

Table 3.9. Cost of Imported Steam Coal for Japan from various sources (Average Unit Value, CIF) [US $/metric tonne]

	Total	Austral.	Canada	USA	S. Africa	CIS	China
1980	54.60	55.41	56.10	70.45	41.46	45.59	50.03
1981	65.22	65.51	62.53	72.63	54.76	63.19	64.79
1982	64.92	64.86	62.70	71.72	61.50	63.43	65.94
1983	55.53	55.92	61.35	66.60	51.91	43.09	54.39
1984	49.67	51.11	48.71	59.71	45.45	38.30	49.09
1985	45.32	44.40	43.66	56.74	45.81	41.08	49.16
1986	44.86	44.44	44.02	55.11	44.96	44.27	45.98
1987	41.49	42.27	40.61	46.89	40.91	39.44	37.80
1988	42.63	43.34	42.95	48.01	41.16	40.23	38.51
1989	48.76	49.78	45.38	52.78	44.68	45.43	45.74
1990	50.98	52.24	48.26	53.16	47.94	46.54	47.59
1991	50.43	51.68	46.76	52.36	48.36	44.93	47.69
1992	48.47	49.29	46.30	51.22	46.92	43.73	46.04
1993*	46.72	46.88	46.92	51.90	45.78	41.74	45.53

* Average for first and second quarters. Source: [32, 33]

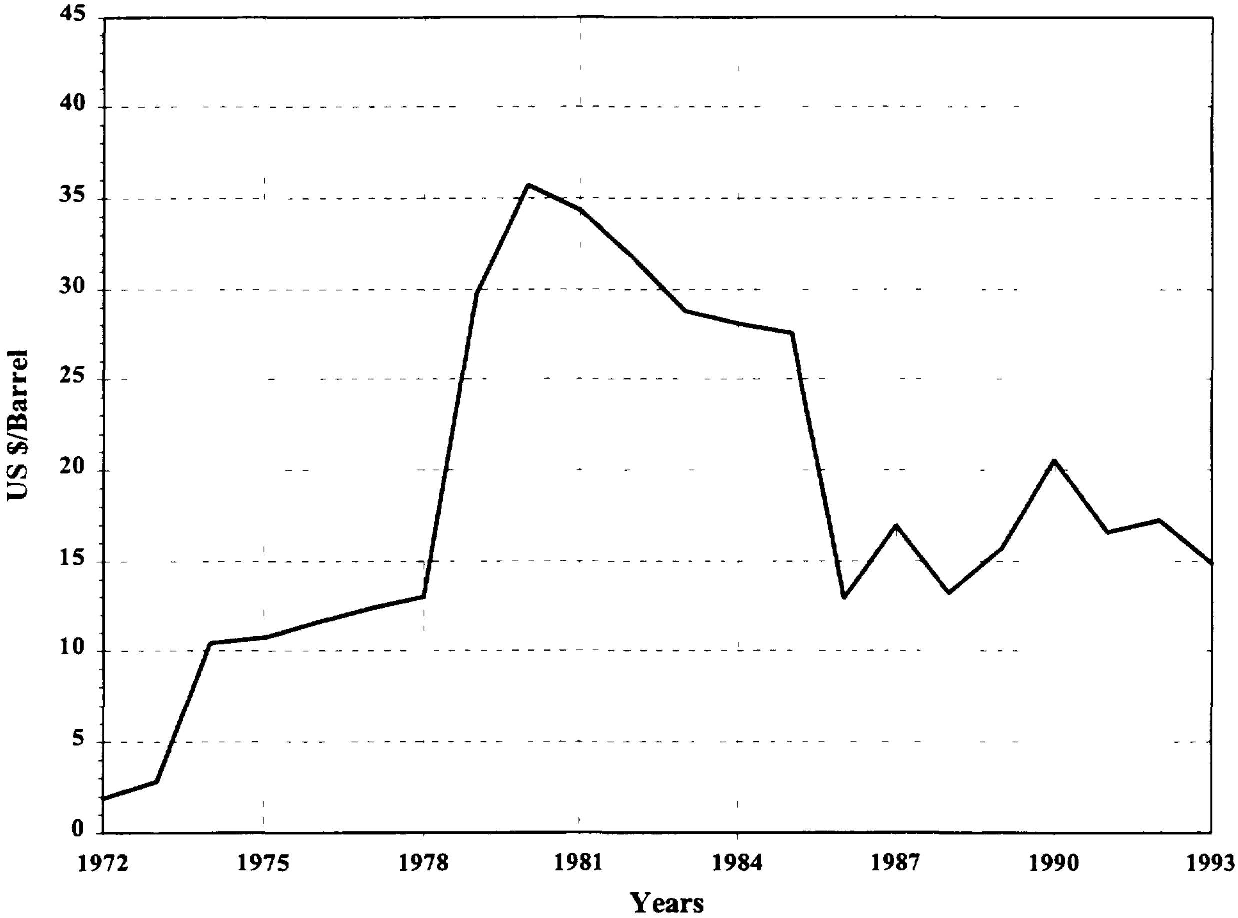


*FIG. 3.2. Historical Spot Price of Crude Oil**

* 1972– 1986 Arabian Light; 1986 – 1993 Dubai
Source: [31]

After reviewing the above mentioned projections by various experts and institutions, projections for future prices of imported fuels have been developed. For imported oil prices, an increase of 1% p.a. in real terms during 1993–2000 has been assumed. In the subsequent period this increase has been assumed as 2% p.a. during 2000–2010 and 2.7% p.a. during 2010–2023. A comparison of these projections with some other recent studies [27, 34 and 35] is given in Fig. 3.3. For imported gas, it has been assumed that its prices will follow the trend of international oil prices. The domestic prices of oil products and gas will also follow the international oil price trend in line with the current policy of the Government. For imported coal based on medium term projections of OECD [27], an increase of 1% p.a. in real terms throughout the planning horizon has been assumed (see Fig. 3.4.). It has been assumed that the prices of domestic coal will also follow the trend of international coal prices.

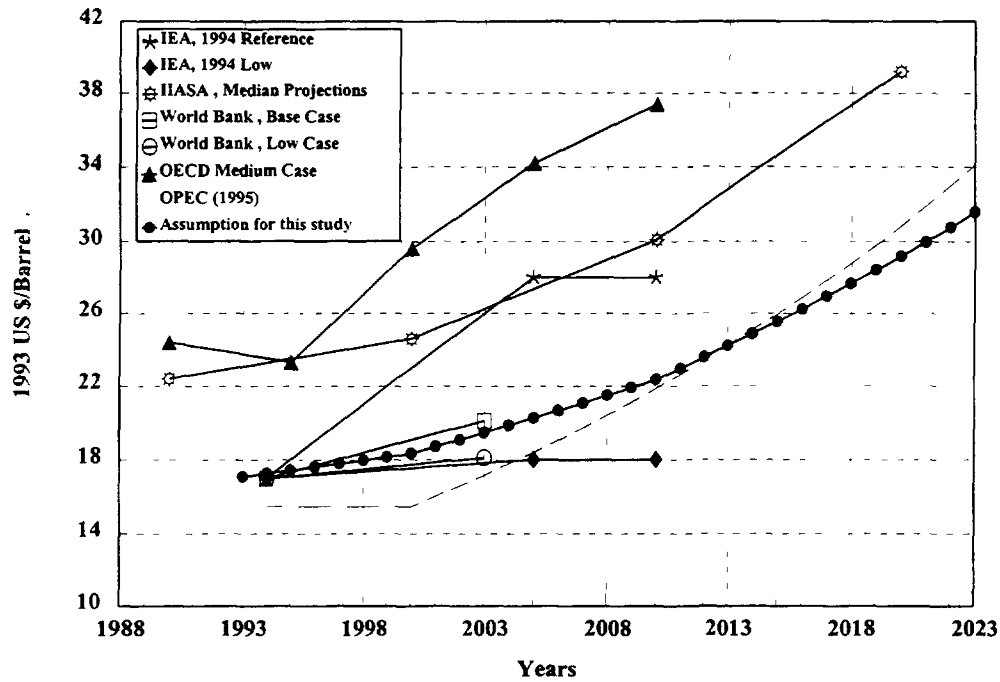


FIG. 3.3. Comparison of oil price projections of this study with some other recent projections

Source: Based on [27, 34 & 35]

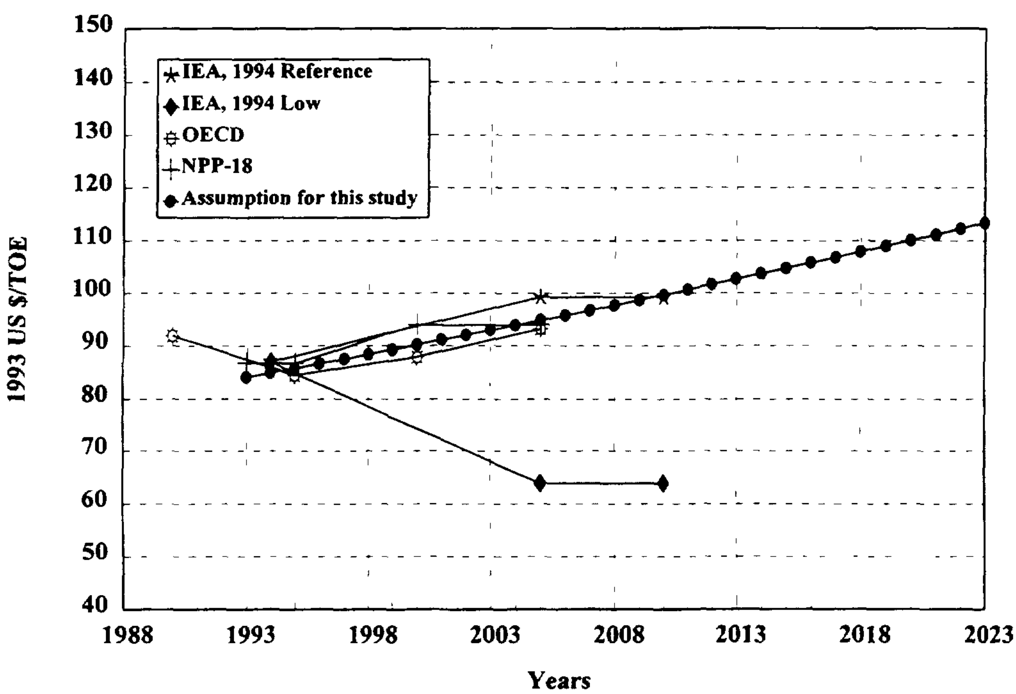


FIG. 3.4. Comparison of coal price projections of this study with some other recent projections

Source: Based on [20, 27]

3.7. Nuclear Power Development

Nuclear power technology was introduced in Pakistan in 1971 when a 137 MW CANDU type reactor was built with Canadian assistance. The construction of Pakistan's second nuclear power plant, a 325 MW PWR, with the assistance of China is underway at present and the plant is expected to be completed by 1998. In spite of the keen interest of Pakistan in the building of additional nuclear power plants, it took some two decades to start construction of the second nuclear power plant due to unfavourable international environment coupled with the lack of indigenous technological and industrial capability for independent design and construction of nuclear power plants. Pakistan is now planning to make large scale use of nuclear power in future. It is planned to systematically develop local capability, leading progressively to increasing indigenous design, engineering and manufacture of nuclear power plants together with their components and fuel.

Two possibilities for nuclear power development have been considered. In one case the nuclear capacity is allowed to increase gradually with the addition of successive 600 MW nuclear power plants. It has been estimated that the maximum technically feasible additions of nuclear power capacity up to the year 2022 would be about 13500 MW. In order to analyse the economic, fuel import and environmental advantages of a nuclear power programme, a "Nuclear moratorium scenario" has also been considered. This scenario includes only the 325 MW nuclear power plant under construction with no further addition of nuclear power plants.

3.8. Energy Efficiency and Conservation

In spite of very low level of present energy consumption, it is believed that a large amount of energy and electricity is wasted due to poor efficiency of end-use appliances and high losses in transmission and distribution. The National Energy Conservation Centre (ENERCON) has been making concerted efforts to reduce energy wastage through encouraging conservation and efficiency improvements. The main thrust of ENERCON's effort is directed towards providing technical support to various energy consumers, manufacturers, public agencies etc., in the form of energy audits, demonstration programmes, feasibility studies or simply expert advice on energy conservation. Some of the specific measures envisaged in different sectors of consumption along with the estimates of energy savings potentials are as follows [36, 37 and 38]:

Industry: Technical services comprising; (a) boiler/ furnace tune-ups; (b) steam system surveys and; (c) electrical system surveys, can each lead to an average efficiency improvement of 5–8%. In brick-kilns up to 30% savings can be achieved by improving the combustion efficiency and design of brick-kilns.

Buildings: By using efficient lighting designs up to 70% of lighting electricity can be conserved. Efficient and improved building designs can save up to 20% of the total energy requirements.

Agriculture: In this sector up to 17% energy can be saved through retrofits, i.e. overhauling of existing tubewells while introduction of improved and efficient design tubewells can save about 35% of the energy. Better operation and maintenance of tractors can lead to about 18% savings in fuels.

Transport: Proper tuning of auto (petrol) cars can conserve up to 10% of the fuel requirements and improving truck designs (i.e. redesigning the crown of private trucks) can save up to 21% of the energy consumed by the present model trucks.

Power: The power sector transmission and distribution losses (including auxiliary consumption) for the country can be reduced from the present level of about 25% to a level of about 15% by the year 2006 by the strengthening of T&D system and adoption of various administrative measures [20]. Appropriate tariff and non-tariff measures can lead to overall energy conservation in the power sector and also reduce peak demand.

Regarding realization of the above mentioned potential for energy efficiency improvement and conservation in various sectors, two cases have been considered viz. one envisaging normal evolution in line with recent experience (reference as nominal case) and the other envisaging vigorous efforts. The second case assumes realization of most of the estimated potential for energy efficiency improvement and conservation by the end of planning horizon. The quantitative details are given in Chapter 4 and Appendix B.

3.9. Environmental Issues

As mentioned in Section 2.7, energy production and use activities are among the largest sources of environmental degradation. The use of non-commercial (traditional) fuels is resulting in deforestation and soil erosion, while the use of commercial fuels is causing deterioration of air quality in the urban areas besides resulting in emission of large quantities of SO_2, NO_x and CO_2. Within energy sector, electricity generation is a major source of emission of these environmentally damaging gases. It is feared that if the present trend of increasing use of fossil fuels for power generation continues in future, the environmental problems will exacerbate in the coming years.

In order to analyse environmental implications of future power generation in Pakistan, particularly that of nuclear power generation, a comparison of alternative plans for expansion of electric sector has been be made with respect to their environmental burdens and costs involved for reduction in environmental emissions.

3.10. Construction of Energy/Electricity Demand and Supply Scenarios

With the combination of the various assumptions, spelled out in the previous sections, on future evolution of demography, economy, energy resource development, fuel prices, etc., energy/electricity demand and supply scenarios have been constructed, which cover a wide range of possibilities for future development. These scenarios are described in the following paragraphs.

Four scenarios for future energy and electricity demand namely Reference Scenario, Optimistic Scenario, Constrained Scenario and Energy Efficiency Scenario have been constructed. The Reference Scenario corresponds to the Planning Target Growth Scenario of economy. The Optimistic Scenario corresponds to Optimistic Growth Scenario of economy while the Constrained Scenario corresponds to Constrained Growth Scenario of economy. The population growth assumption is common to all scenarios, while nominal evolution of energy efficiency improvement is assumed for the Reference, Optimistic and Constrained Scenarios. The Energy Efficiency Scenario corresponds to the Planning Target Growth Scenario of

Table 3.10. Summary of Analyses Reported in This Study

Scenario/Case Building Blocks	Energy and Electricity Demand Analysis Cases	Energy Supply Analysis Cases	Electric System Expansion Analysis Cases	Environmental Analysis* Cases	Financial Analysis Case
A. Economic Growth A1 Planning target growth scenario A2 Optimistic growth scenario A3 Constrained growth scenario **B. Demography** Population growth projections are common in all the scenarios Some of the parameters have been assumed to change with economic growth scenario **C. Energy Efficiency Cases** C1 Nominal energy efficiency improvement case C2 Vigorous energy efficiency improvement case **D. Indigenous Energy Resource Development** Development of oil, gas and hydro resources is common in all the energy supply and electric system expansion cases The development of coal resources has been assumed to be more rapid in Optimistic Case/Alternative IV **E. Gas Imports Cases** E1. Gas import allowed E2 Gas imports not allowed **F. Nuclear Power Development Cases** F1 Gradual development of nuclear power F2 No further development of nuclear power **G. Energy Price Scenarios** 1 An increase of 70% in real terms assumed in oil and gas prices and 35% in coal prices over the 30 year period 2 Prices to remain constant in real terms (for sensitivity analysis only)	**1. Reference Scenario** (Combination of A1 & C1) **2. Optimistic Scenario** (Combination of A2 & C1) **3. Constrained Scenario** (Combination of A3 & C1) **4. Energy Efficiency Scenario** (Combination of A1 & C2)	**1. Gas Imports Case** (Reference scenario of energy demand with E1 & F1) **2. No Gas Imports Case** (Reference scenario of energy demand with E2 & F1)	**1. Reference Case** (Reference scenario of electricity demand with E1 & F1) **2. Nuclear Moratorium** Case/ Alternative I (Reference scenario of electricity demand with E1 & F2) **3. No Gas Imports Case/ Alternative II** (Reference scenario of electricity demand with E2 & F1) **4. Energy Efficiency Case/ Alternative III** (Energy efficiency scenario of electricity demand with E1 & F1) **5. Optimistic Case/ Alternative IV** (Optimistic scenario of electricity demand with E1 & F1) **6. Alternative V** (Reference Case with private sector plants)	**1. Case 1** (Reference Case of Electric System Expansion Analysis) **2. Case 2** (Nuclear moratorium case of electric system expansion analysis) **3. Case 3** (Nuclear moratorium case of electric system expansion analysis with air pollution control devices added to some of the coal and oil fired power plants to bring down the emissions of SO_2 and NO_x to the levels of the Case 1)	Financial analysis of nuclear power development programme of the **Reference case** of electric system expansion analysis, and sensitivity analysis of the results with respect to i) increased capital cost ii) higher foreign interest rate iii) rapid deterioration of exchange rate iv) lower price of electricity sales

* Environmental analysis has been carried out for the power sector only

economy and energy efficiency improvements in line with vigorous energy efficiency policy case.

On the supply side, two possibilities for overall energy supply–demand balance are considered, viz. with imported gas and without import of gas. These two scenarios are considered for the Reference Scenario energy demand and have been constructed to analyse allocation of available energy supplies between power and non-power sectors.

As for the future expansion of electricity generation system, five cases have been considered. The Reference Case assumes electricity demand as projected in the Reference Scenario, maximum feasible development of indigenous energy resources along with the possibility of import of gas. Two alternatives to the Reference Case considered are a nuclear moratorium case and a case without import of gas. In addition to these three cases, electric system expansion corresponding to optimistic demand scenario and energy efficiency scenario have also been considered.

Besides the above five cases for the analysis of future expansion of electricity generation system, another case has been analysed to assess the impact of incorporating the planned private power projects as firmly committed plants. About 4,300 MW capacity is being planned by the private power sector for which various agreements have been concluded between the Private Power and Infrastructure Development Board and the private investors. These plants in the Reference case were assumed to be candidate plants.

Environmental analysis of two electric system expansion cases, i.e. the Reference Case and Nuclear Moratorium Case have been considered, while the financial analysis of only nuclear power development in the Reference Case has been considered. Table. 3.10 summarises the construction of all these scenarios.

Chapter 4

ENERGY AND ELECTRICITY DEMAND ANALYSIS

4.1. Introduction

Projection of energy demand is the first analytical step of the overall integrated energy planning following the collection and organization of energy data and formulation of economic growth scenarios. There are a number of approaches and techniques that are now in use for projecting energy demand for an economy or for different economic sectors separately, and with the time horizon varying from a few years to several decades. These techniques vary from some very simple ones requiring minimal amount of data and needing only desk top calculators to others that are very data intensive and need digital computers for their applications. For the present study the MAED model has been used for the analysis and projections of the demand for energy by various economic sectors as well as by categories of different end uses. This model provides a detailed framework for estimating energy demand implications of a user specified socioeconomic and technological development scenario. A brief account of the methodology of this model is given in Chapter 1.

The first step in the application of the MAED model is the reconstruction of the energy consumption by sector and by categories of end uses for a base year. This step, which aims at facilitating the understanding of energy consumption mechanism, requires detailed information about demography, economy, energy consuming technologies/equipment and energy consumption. In the second step, several probable demographic, economic and technological development scenarios are constructed and the corresponding demand for energy is estimated.

Details concerning the reconstruction of the energy consumption for the base year are presented in Appendix A and the description of how the statistical data and other available information was processed in order to prepare input data related to the four scenarios is given in Appendix B.

4.2. Reconstruction of the Base Year of the Study

The application of the MAED model requires detailed information about demography, economy, energy consumption including energy consuming technologies, etc. This information is required to be assembled at first for a base year which is used as the reference year for perceiving the evolution of energy system in future. Selection of the base year is made on the basis of, (i) availability of data and (ii) the assessment that the data are representative of the economic and energy situation of the country. As the Applied Systems Analysis Group had already carried out some studies on energy demand assessment for Pakistan using an adapted version of MEDEE-2 model [39, 40], the status of availability of data was known to the study team. After reviewing the available data and considering the five year planning cycle in Pakistan, the 1992–93 fiscal year has been selected as the base year for the study. This fiscal year corresponds to the end of the 7th Five Year Plan.

Most of the information needed for the application of the MAED model was available for the base year. However, in some cases either the information available was not up-to-date, or no information was available. In such cases estimates have been made on the basis of information available for some previous year or reported in the literature for other countries. The main data sources and assumptions for this phase of the study are summarized below.

A summary of demographic parameters, structure of GDP and composition of manufacturing sector, for the base year, has already been given in Chapter 3. The following section describes the major assumptions made for regrouping/estimation of base year energy consumption and for derivation of base year MAED parameters.

4.2.1. Energy Consumption

Energy consumption data are regularly collected and published by the Ministry of Petroleum and Natural Resources in its annual publication Energy Yearbook. These data are collected from oil distribution companies, gas distribution companies and power utilities and federal and provincial departments relating to coal mining.

One anomaly of the published data on energy consumption is that the use of HSD for tractors and other farm machinery (other than diesel operated irrigation pumps) is lumped in the transport sector. The consumption of HSD for tractors and other farm machinery has been estimated on the basis of information about the number of tractors, their average fuel usage and their annual utilization, available from various sources [10, 41, 42] and the estimated HSD consumption in the Agriculture sector has been deducted from the Transport sector.

. Energy consumption data for the Construction sector are not available. The fuel use in this sector has been estimated by assuming an energy intensity of 0.5 Mcal/US $ for Pakistan in 1992–93, in the light of 1980s data of some Asian countries. The estimated Construction sector HSD consumption has been deducted from the transport sector.

The Mining sector energy consumption data are also not available and are included in the industrial sector. Based on responses to questionnaires for Census of Mining Industries 1988–89, carried out by the Federal Bureau of Statistics (FBS), the fuel use in this sector has been estimated.

Although the fuel consumption data of the Manufacturing sector as a whole are available, its breakdown into four sub-sectors (i.e. basic materials, machinery and equipment, consumer goods and small scale industries) is not available and was estimated on the basis of [43] and reports of OCAC and Gas Distribution Companies [44–47]. Further, the self-generated and co-generated electricity consumption by the four manufacturing sub-sectors was estimated in the light of information given in [48– 51].

Electricity used in oil transportation through pipelines is not reported separately and is included in the manufacturing sector. This electricity use has been estimated from specific electricity consumption of 0.0358 kW·h/ton-km reported in [52].

The use of non-commercial fuels in urban and rural households has been estimated from [15].

Final energy consumption data for the base year as given in Pakistan Energy Yearbook and as reconstructed for the MAED application are given in Tables 4.1 and 4.2, respectively. The difference between the two tables is due to different accounting of consumption of various fuels in some sectors, as explained above, and the use of coal which is believed to be under reported in the Energy Yearbook, as pointed out in [29]. In the light of the Energy Wing's estimates, the coal consumption figure for manufacturing sector has been increased by a factor of 1.5.

Table 4.1. Commercial Final Energy Consumption (1992–93) as given in the Pakistan Energy Year Book

Energy Uses: **Unit: TOE**

Sector	M S	HOBC	Kerosene	H S D*	L D O	F Oil	Aviation Fuel	Total Oil Products	LPG**	Gas	Coal	Electricity	Total
Domestic			641 734					641 734	109 016	1 773 331	1446	1 072 565	3 598 092
Agriculture					299 243			299 243				458 914	758 157
Transport	1 081 738	146 946	1279	4 886 376	1010	45 713	253 800	6 416 862		736		2199	6 419 797
Industries				126 087	541	1 323 694		1 450 322		3 606 926	1 439 122	1 062 222	7 558 592
Commercial									36 339	335 228		190 000	561 566
Other Govt	17 277	8395	17 393	132 050	286	24 363	173 764	373 528				186 009	559 537
Total	1 099 015	155 341	660 406	5 144 513	301 080	1 393 770	427 564	9 181 689	145 355	5 716 221	1 440 568	2 971 908	19 455 741

* HSD consumption for tractors in agriculture sector is not separately available and is included in the transport sector

** 75% of total LPG is allocated in Domestic Sector and 25% in Commercial Sector

Non-Energy Uses:

1	Fertilizer Feed Stocks (Gas)	1 377 217	TOE	(60% of supplies to fertilizer)
2	Coke	653 887	TOE	
3	Oil	416 699	TOE	(Production+Imports-Exports)
4	Total	2 447 803	TOE	
5	Bunkers	176 386	TOE	

Table 4.2. Final Energy Consumption Reconstructed for the Base Year (1992–93)

Energy Uses: **Unit: TOE**

Sector	M S	HOBC	Kerosene	H S D	L D O	F Oil	Aviation Fuel	Total Oil Products	LPG	Gas	Coal	Electricity	Total Comm Fuels	Total Non-Comm Fuels
Agriculture				1 450 184	299 243			1 749 427				458 914	2 208 341	
Construction				90 000				90 000				450	90 450	
Mining				53 088				53 088		635		1571	55 294	
Manufacturing				72 999	541	1 323 694		1 397 234		3 606 291	2 158 683	1 050 882	8 213 090	2 078 810
Transport	1 081 738	146 946	1279	3 346 192		43 759	240 116	4 860 030	21 803	736	496	11 518 **	4 894 583	
Misc Transport	17 277	8395	17 393	132 050	1296	26 317	187 448	390 176					390 176	
Domestic			453 706 *					453 706	87 213	1 773 331	1446	1 072 565	3 388 261	18 231 000
Service			188 028					188 028	36 339	335 228		376 008	935 603	
Total	1 099 015	155 341	660 406	5 144 513	301 080	1 393 770	427 564	9 181 689	145 355	5 716 221	2 160 625	2 971 908	20 175 798	20 309 810

Total including Non-Commercial fuels 40 485 608 TOE

* Includes 402 210 TOE of kerosene consumption for lighting by non-electrified households
** Includes 9319 TOE consumed in pipelines for petroleum transportation and 2199 TOE used in Traction

Non-Energy Uses:

1	Fertilizer Feed Stocks (Gas)	1 377 217	TOE
2	Coke	653 887	TOE
3	Oil	416 699	TOE
4	Total	2 447 803	TOE
5	Bunkers	176 386	TOE

4.2.2. Estimation of Base Year MAED Parameters

The application of the MAED model requires the determination of several parameters for the base year and then their projections for the selected future years. The number of such parameters is about 200. In the present study some additional variables have been considered for the projection of energy demand of the Agriculture sector. In view of the large differences in the income and energy consumption patterns, the energy demand of households has been analysed and projected separately for rural and urban households, and then combined to get the energy consumption of all the households. Further, projection of energy consumption in some activities, i.e. electricity used in transportation of oil through pipelines, non-energy oil products consumption in various sectors, feedstocks used in the fertilizer industry and kerosene used for lighting, has been made outside the model, due to either the inability or inflexibility of the MAED model in handling these activities. All the base year parameters, and projected parameters, are given in Table B.1, of Appendix B.

The sectoral value added and the final energy consumption, in the base year are used to estimate the energy intensities of motor fuels and specific uses of electricity for the Agriculture, Construction and Mining sectors (see Table 4.3).

Manufacturing sector is generally very energy intensive. Due to the possibility of interfuel substitutions, technological developments leading to efficiency improvements and possibility of co-generation of electricity, the thermal uses in Manufacturing sector are considered at the level of useful energy. Table 4.4 gives the base year energy intensities of the four manufacturing sub-sectors. Information about the distribution of useful thermal energy requirements of Manufacturing among furnace and direct heat, steam, and space/water heating in Pakistani industries is not available. These distributions have been assumed in the light of information about the use of thermal energy in Manufacturing industries of some developing countries (i.e. Republic of Korea and Thailand) for which such information was available in the literature [53, 54]. For the derivation of the MAED parameters related to co-generation the ratio of heat/electricity in the output of co-generation systems has been assumed as 3:1 in line with Ref. [55]. The efficiency of co-generation has been assumed as 70% and that of self-generation has been assumed as 30%.

Table 4.3. Energy Intensity in Agriculture, Construction, Mining and Manufacturing Sectors for the Base Year (1992-93). [Final Energy /10^3 Rs. of Value Added]

	Value added 10^9 Rs.	Motor fuels [kcal/ Rs.]	Specific uses of electricity [kW·h/10^3 Rs.]	Thermal uses [kcal/ Rs.]
Agriculture	297.816	62.1	18.9	0
Construction	49.807	19.1	0.1	0
Mining	7.403	76.7	2.6	0
Manufacturing	207.568	3.7	71.5*	288 [useful energy] 458 [final energy]

* Includes self-generated and cogenerated electricity, estimated as 15% of the grid supplied electricity

Table 4.4. Energy Intensity in the Manufacturing Subsectors for the Base Year (1992-93)

	Value added 10^9 Rs.	Motor fuels [10^3 kcal/10^3 Rs.]	Specific uses of electricity* [kW·h/10^3 Rs.]	Thermal uses [Useful energy] [kW·h/10^3 Rs.]
Basic material	50.636	7.9	135.9	829
Machinery & equipment	14.262	2.4	40.6	88
Consumer goods	77.402	2.4	70.3	336
Miscellaneous	65.268	2.4	29.7	5
Manufacturing total	207.568	3.7	71.5	335

* Includes self-generated and cogenerated electricity, estimated as 15% of the grid supplied electricity

Fuel used in the Transport sector during the base year 1992-93 has been divided into three categories: (a) Railways: based on information from Pakistan Railways Yearbook [57], (b) Air transport: in the light of information obtained from OCAC [44] and (c) Road transport: as the reminder of total fuel use by transportation. Fuel consumption in road transport has been further segregated into passenger and freight categories for intercity and intracity road transportation using the information available from:

(a) The Economic Survey [10] on population of transport vehicles on road,

(b) The study [56] conducted by Japan International Cooperation Agency (JICA) on shares of urban and intercity vehicles, load factors, average annual utilization of each vehicles and average fuel consumption by various type of vehicles on level road in Pakistan.

The estimated diesel and gasoline consumption were about 13% and 15% lower than the respective fuel use given in Table 4.2. As the MAED model considers only six types of road vehicles i.e. intercity and intracity cars, buses and trucks, all the vehicles were grouped into intercity and intracity effective cars (one effective car equals to one car or one taxi or one jeep or 1.5 rickshaws or 3 motorcycles), effective buses (one effective bus equals to one bus or 2.43 mini buses or 3.64 wagons or 5.46 pick-ups) and effective trucks (one effective truck is equivalent to one conventional truck or 0.355 truck trailer or 11.36 delivery vans) on the basis of load factors given in the JICA study. Then by an iterative process, judgementally various MAED related parameters were derived for effective cars, buses and trucks. The MAED parameters for railways were derived from the data in [57].

A recent survey for the Household Energy Strategy Study (HESS) gives details of the use of commercial as well as non-commercial fuels in urban and rural households by type of activity [15, 58 and 59]. Based on these estimates the energy consumption data for the household sector were dis-aggregated into rural and urban households by type of activity (i.e. cooking, water heating and space heating). However, for rural households the thermal use of energy was not dis-aggregated into different activities because of the fact that rural households mainly use non-commercial fuels which are neither suitable for indoor space heating nor for hot water supply, as concluded by HESS. As for electricity, its use in households has been increasing at very high rates (12-16%) in recent years, both due to increase in number of electrified houses and increase in electricity consumption by already electrified houses with increasing incomes. HESS data have also been used to derive the electricity consumption related parameters of MAED. Using the above described data, the module 1 of MAED model was executed for the base year only to validate various input parameters of the model. Some of the model parameters were adjusted judgmentally in order to obtain exact reconstruction of base year energy consumption.

4.3. Energy Demand Scenarios

In the MAED methodology, a scenario means a set of coherent evolution of the parameters related to the demographic, socioeconomic and technological development of the country. To analyse the medium to long term evolution of energy and electricity demand, four scenarios viz. Reference Scenario, Optimistic Scenario, Constrained Scenario and Energy Efficiency Scenario, practically covering a wide range of possible situations in Pakistan, have been studied. As already mentioned in Chapter 3, the total population growth in all the four scenarios has been assumed to be the same. The Reference, Optimistic and Constrained scenarios correspond to the three national economic growth scenarios viz. Planning Target Growth Scenario, Optimistic Growth Scenario and Constrained Growth Scenario, respectively, and the nominal energy efficiency improvement case. The Energy Efficiency Scenario corresponds to the Planning Target Growth Scenario and energy efficiency policy case.

The most important determinants of energy demand that can be reflected in the MAED model are indicated in Table 4.5. The following sections describe the base year and projected values of the main MAED parameters for the four energy demand scenarios. A detailed description of the basis of projection of all the MAED parameters and a listing of their values are given in Appendix B.

4.3.1. Reference Scenario

The base year and projected values of macroeconomics parameters for different economic development scenarios and of demographic parameters for the Planning Target Growth Scenario have already been described in Chapter 3.

4.3.1.1. Specific energy intensity in industry

The sectoral value added for the base year and the final energy consumption in the same year (see Table 4.2) are used to estimate the energy intensities of motor fuels, specific uses of electricity and thermal uses for the Agriculture, Construction, Mining and Manufacturing industries. The base year values are reported in Table 4.3. It may be noted that: (i) motor fuel intensity of Agriculture and Mining activities are relatively high while that of Manufacturing sector is relatively low; (ii) intensity of specific uses of electricity in the Manufacturing and Agriculture sector are high, while in the Mining and Construction sectors are very small; (iii) the Manufacturing sector is very energy intensive, in terms of thermal uses. The breakdown of Manufacturing sector into sub-sectors indicates that basic materials industries are the most energy intensive in terms of motor fuels, specific uses of electricity and thermal uses (see Table 4.4)

The assumed evolution of energy intensities in industry for the Reference scenario is presented in Table 4.6.

Table 4.5. Main Factors Affecting the Energy Demand in the MAED Model

Category	Factors
1. Macroeconomics	Total GDP GDP structure by economic sectors
2. Demography	Total population Distribution in rural/urban/large cities Total labour force Household size (inhabitants/household)
3. Consumption sector	
3.1 Industry (Agriculture, Construction, Mining and Manufacturing)	Specific energy intensity for each category of end-use Improvement of efficiency Electricity penetration into heat market
3 2 Transportation	Volume of freight and passenger transportation Distribution of freight and passenger transportation Specific energy consumption and load factor of each mode of transport
3.3 Service	Sector labour force Floor area Specific energy consumption by end-use category - Space and water heating; - Electrical appliances; - Air conditioning Electricity penetration
3.4 Household	Type, size and share of dwellings - single family house, apartment, room; - demolition rate; - share of dwellings with hot water facilities; - share of dwellings with air-conditioning; - improvement of insulation; - electrical appliances endowing

Table 4.6. Summary of Final Energy Intensity in Industry (Reference Scenario)

Unit: kW·h/10^3 Rs.

Sector	1992-1993	2002-2003	2012-2013	2022-23
Agriculture				
Total Final Energy Intensity	91	75	60	46
- Motor fuel	72	61	49	38
- Electricity, specific uses	19	14	11	8
- Thermal uses	0	0	0	0
Construction				
Total Final Energy Intensity	22	27	33	42
- Motor fuel	22	27	32	39
- Electricity, specific uses	0	0	1	2
-Thermal uses	0	0	0	0
Mining				
Total Final Energy Intensity	92	137	181	226
- Motor fuel	89	134	178	223
- Electricity, specific uses	3	3	3	3
- Thermal uses	0	0	0	0
Manufacturing				
Total Final Energy Intensity	608	549	505	480
- Motor fuel	4	5	5	5
- Electricity, specific uses	71	81	86	88
- Thermal uses	533	463	414	387

4.3.1.1.1. Agriculture sector

In the Agriculture sector only the use of farm machinery and water pumping activities have been considered, while thermal processing of agricultural products is covered under the Manufacturing sector.

Requirements of motor fuels and electricity for irrigation water pumping have been projected by considering parameters such as: (i) cultivated area, (ii) fraction of cultivated area which is irrigated, (iii) water availability per irrigated acre, (iv) surface water availability at farm gate, (v) energy intensity of water pumping, (vi) fraction of diesel pumps in total useful energy in pumping, and (vii) efficiencies of diesel and electric pumps.

Similarly, motor fuel requirements of tractors have been estimated by considering: (i) tractor population per unit of arable land, (ii) annual hours of use per tractor, and (iii) hourly fuel consumption of a tractor. Detailed information about these parameters are given in Section 1.2 of Appendix B. The projected requirements of motor fuels for irrigation and tractors have been used to workout the intensity of motor fuels in agriculture.

The intensity of motor fuel use in agriculture has been projected to decline by about 47% by the year 2022-23. This reduction in intensity is primarily due to the following assumptions: (i) the fuel consumption per tractor per hour will decline by about 10% over the next 30 years, (ii) due to increasing rural electrification programmes the use of diesel operated tubewells will become essentially negligible by the year 2022-23, and (iii) the share of non-crop agriculture sub-sectors i.e. livestock, fishing and forestry, which are believed to be on average much less energy intensive than the two activities considered, will increase in future.

As a result of assumed improvements in the efficiency of electric irrigation pumps from about 27% in 1992–93 to 35% in 2022–23, the intensity of electricity use in Agriculture has been projected to decline from 16.28 kcal/Rs. to 6.8 kcal/Rs. This reduction is due to (i) change in structure of agricultural value added, (ii) saturation in water pumping due to limited size of underground aquifer, and (iii) assumed improvement in the efficiency of electric irrigation pumps.

4.3.1.1.2. Construction sector

Since no historical data are available for energy consumption of the Construction sector, projections for this sector have been done in the light of the experiences of other countries [54, 60 and 61]. It is assumed that the energy intensity for motor fuels will gradually increase to 1.75 times of the base year value in 2022–23. Presently, a small quantity of electricity is being consumed in the construction sector, however, keeping in view the data of some developing countries, it is assumed that electricity penetration rate in this sector will be 10% p.a. during the next thirty years. With this assumption, electricity intensity will be 3.5, 8.8, and 19.4 with respect to the base year in 2002–03, 2012–13, and 2022–23, respectively.

4.3.1.1.3. Mining sector

Energy intensities for the mining sector have been projected in the light of historical estimates and keeping in view the potential of different sub-sectors, such as coal mining, oil and gas extraction, etc. It is assumed, judgmentally, that the electricity intensity will remain constant during the planning study period and the intensity of motor fuels use in this sector has been assumed to increase by a factor of 1.25 in the first period which gradually increases up to 2.50 in the last period with respect to the base year.

4.3.1.1.4. Manufacturing sector

The factors determining the change of energy demand in the Manufacturing sector include changes in sub-sectoral contribution in value added of Manufacturing sector, changes in energy intensities, changes in energy efficiencies and penetration of new energy sources and technologies.

During the last ten years the intensity of thermal uses has decreased by about 16%, while the intensity of specific electricity uses has increased by about 19%. In the case of motor fuels the trend is not very clear due to relatively small quantities of the fuels used (see Table 4.7). The reduction in intensity of thermal uses is believed to be the result of energy conservation measures and technological improvements over this period, while the increase in intensity of electricity is an effect of higher automation in the manufacturing sector.

In line with the historic trend it has been assumed that the energy intensity for thermal uses will decrease by 25% over the 30 years planning period compared to the 16% decline in the past 10 years. The assumed pace of decline in the energy intensity is rather slow compared to the past experience because of saturation effect. As for intensity of electricity use, an increase of only 15% over the next 30 years has been assumed compared to the 19% increase in the last 10 years. In this case two opposite effects, viz. increase in automation and improvements in the end-use efficiency, have been assumed to lead to an overall increase in the intensity of electricity use.

Table 4.7. Evolution of Energy Intensity of Manufacturing Sector during 1983–1993

	1982–83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	1991-92	1992–93
Energy Consumption [000 TOE]:											
Motor Fuels (HSD+LDO)	60 44	18 48	19 12	28 41	75 06	41 19	38 60	44 15	43 26	50 72	73 54
Electricity*	448 15	473 22	502 61	587 18	644 64	721 98	757 70	831 29	905 50	991 75	1050 88
Thermal Uses	4246 75	4565 26	4929 74	5011 50	4788 42	5706 42	5785 92	6319 77	6290 13	6940 40	7088 67
(Coal+Gas+F O+Kerosene)											
Value Added (Billion Rs. of 1992–93)	104 86	113 14	122 31	131 57	141 50	155 57	161 92	171 31	182 12	196 80	207 57
Energy Intensities [TOE/Million Rs]:											
Motor Fuels	0 6	0 2	0 2	0 2	0 5	0 3	0 2	0 3	0 2	0 3	0 4
Electricity *	4 3	4 2	4 1	4 5	4 6	4 6	4 7	4 9	5 0	5 0	5 1
Thermal Uses	40 5	40 3	40 3	38 1	33 8	36 7	35 7	36 9	34 5	35 3	34 2

* Grid supplied electricity only, expressed in TOE of final energy at 1 GW·h = 81.44 TOE

Table 4.8. Electricity Penetration in Industry (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Ratio of Electricity intensity versus base year in:				
-Agriculture	1.000	0.754	0.577	0.416
-Construction	1.000	3.540	8.780	19.410
-Mining	1.000	1.000	1.000	1.000
-Manufacturing	1.000	1.093	1.138	1.150
Share of useful thermal energy which is supplied by electricity in Manufacturing for process:				
- Furnace/Direct Heat	0.000	0.010	0.060	0.100
- Space/Water Heating	0.000	0.000	0.000	0.000

The above changes in the intensities have been assumed under the condition that the shares of value added by various sub-sectors of the manufacturing sector remain unchanged in future. However, as these shares have been assumed to change, the overall changes in the intensities will be somewhat different then the above assumed values. These values for the different sectors are given in Table 4.6. A summary of electricity penetration in Industry is given in Table 4.8.

4.3.1.2. Changes in energy efficiency and penetration of co-generation in manufacturing

The end-use efficiency of substitutable fossil fuels has been assumed to improve gradually from a level of 65% in the base year to a value of 72.5% by the terminal year of the study. These improvements are expected in view of technological improvements.

Keeping in view the recent trend for better utilization of energy resources in the Manufacturing sector it is assumed that the share of co-generated heat in low temperature steam demand will increase from about 18% in the base year to 25% by the year 2022–23.

4.3.1.3. Shares by mode and specific energy consumption in transportation

In the MAED model four types of transportation activities, viz. (i) freight transportation, (ii) intercity passenger transportation, (iii) urban passenger transportation and (iv) miscellaneous transport (includes military, government and miscellaneous uses), are considered. In the base year the share of fuels used for freight, intercity passenger, urban passengers and miscellaneous transportation were 46%, 28%, 19% and 7%, respectively. Further, of the fuels used for transportation, 84% were used for road, 5% were used for air, 4% were used for rail, 7% were for used for miscellaneous use and only 0.2% were used by pipelines.

4.3.1.3.1. Freight transportation

Freight transportation activity levels have been projected on the basis of a linear equation linking freight ton-km with the sum of the value added of the Agriculture, Mining, Manufacturing and Energy sectors. The constant and slope of the linear equation were determined by fitting a straight line equation to 1993 data and 8th Plan target for 1998. Projected growth rates of ton-km for the period 1993–2003, 2003–2013 and 2013–2023 are 4.1% p.a., 5.2% p.a. and 6.3% p.a. respectively, with the average for the 30 years period being 5.2% p.a.

During the last two decades the share of trains in freight transportation has been declining while the share of trucks (intercity and local) has been increasing. As the declining share of railways would involve extra costs to the economy, the Sixth and Seventh Plans aimed at reversing this trend; however, this was not achieved. The Eighth Plan, without assigning any target, also envisages increasing the share of the railways. A share of 31.5% for railways and 47.3% for intercity trucks by 2022–23, has been assumed keeping in view the Seventh Plan targets for 2005–06. (These shares correspond to shares of 40% and 60% for railways and intercity trucks respectively between these modes only). The shares of local trucks and pipelines have been judgmentally assumed to remain constant at about 11.2% and 10%, respectively in the period 1998–2023. The steam freight trains are assumed to be completely phased out by 2008. The share of electric trains in freight transportation by train has been judgmentally assumed to increase from 3% in 1992–93 to 16% by 2022–23 in view of the proposals for electrification of various sections of the railways [56]. Figure 4.1 shows the historical and projected shares of trucks, trains and pipelines in freight transport.

The energy intensities of the freight trains, intercity trucks and urban trucks are assumed to decline gradually and reach a level of 90% of the base year values. Presently, the main oil pipeline is being used for transporting HSD and Kerosene only and the planned pipeline projects include crude oil and furnace oil pipelines so it is assumed that energy intensity of the pipelines will gradually increase from 30.8 kcal/ton-km in 1992–93 to a level of 35.0 kcal/ton-km by 2022–23. Table 4.9 shows the base year and projected freight activity levels, the shares by mode and energy intensities.

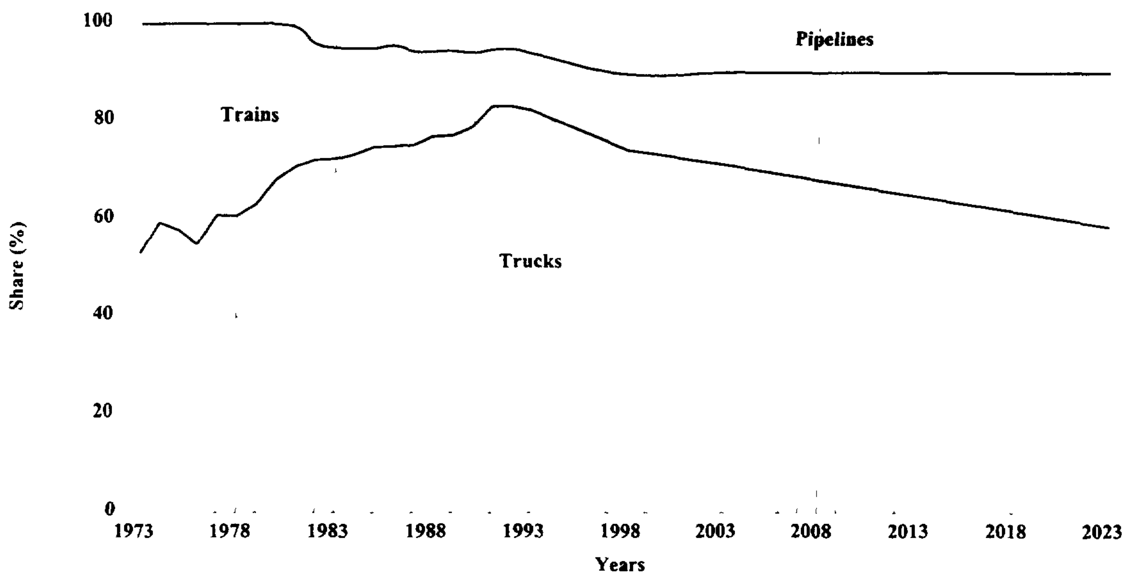


FIG. 4.1. Historical and Projected Shares of Different Modes in Total Freight Traffic (Excluding Air)

Table 4.9. Activity Levels and Energy Intensities in Freight Transportation (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Total activity (10^9 ton-km)	52.673	79.017	131.626	241.422
Share by mode (%)				
Truck	82.2	71.3	64.9	58.5
Local	(14.5)	(15.6)	(17.3)	(19.1)
Long-distance	(85.5)	(84.4)	(82.7)	(80.9)
Train	11.7	18.7	25.1	31.5
Steam	(0.10)	(0)	(0)	(0)
Diesel	(97.0)	(95.5)	(91.0)	(84.0)
Electric	(3.0)	(4.5)	(9.0)	(16.0)
Pipelines	6.1	10.0	10.0	10.0
Energy intensity (kW·h/ton-km)				
Truck				
Local	1.020	0.986	0.951	0.919
Long-distance	0.609	0.588	0.567	0.547
Train				
Steam	0.932	0.901	0.870	0.839
Diesel	0.105	0.101	0.098	0.094
Electric	0.037	0.036	0.035	0.033
Pipelines	0.036	0.037	0.039	0.041

4.3.1.3.2. Intercity passenger transport

Japan International Cooperation Agency (JICA) study of 1988 had projected the intercity (rail and road) PKM to increase by 4.4% p.a. during the period 1986–2000. Based on these projections and review of historical data it has been assumed that intercity passenger travel will increase by 3.1%, 4.2% and 5.2% p.a. during the 1993–2003, 2003–2013 and 2013–2023, respectively.

The shares of buses and airplanes in intercity passenger travel (excluding cars) have been increasing with time while the share of railways has been declining. For 1998 the shares of different transportation modes have been projected in the light of the 8th Plan targets. For the period beyond 1998 it has been assumed that the share of railways will remain constant at 12%, the share of travel by bus will decline slightly and the share of air travel will increase correspondingly. Figure 4.2 shows the historical and projected shares of planes, trains and buses in intercity passenger transport excluding cars. Further, it is assumed that steam trains will be completely phased out by 2008 and the share of electric trains in railways will increase with time, in the period beyond 1998.

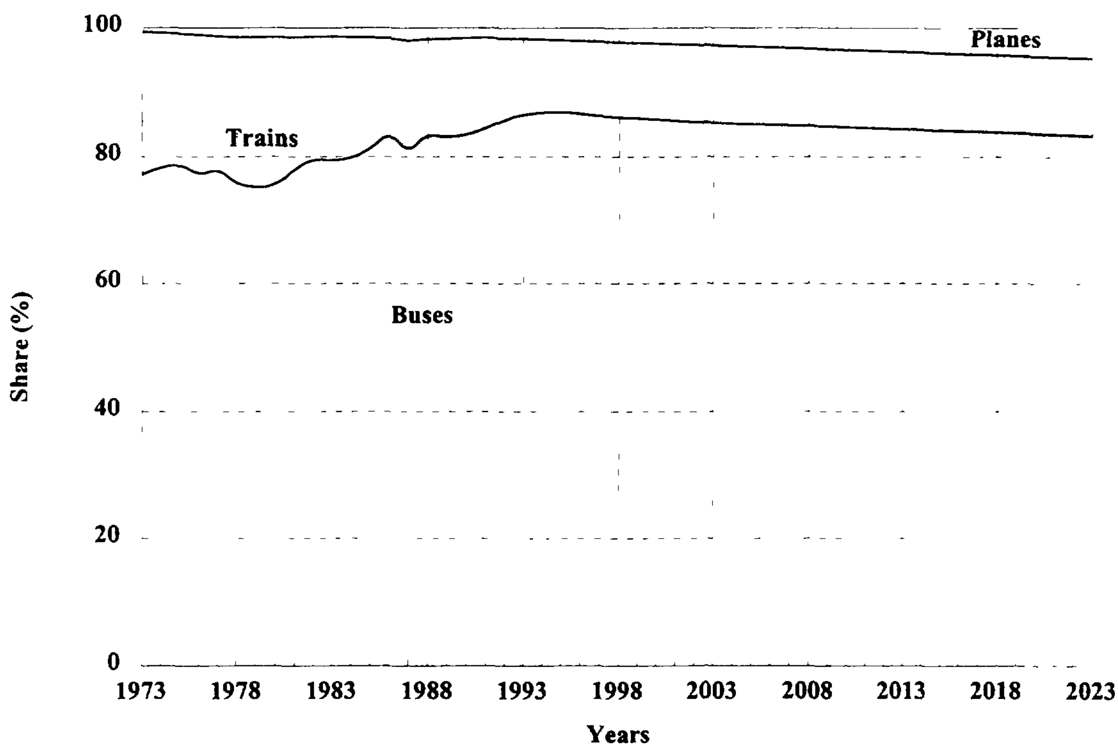


FIG. 4.2. Shares of Different Modes in Intercity Passenger Traffic (Except Cars)

It has been assumed that the number of persons per bus and number of persons per train will decline gradually with time to reflect improvements in the quality of service. For, airplanes the load factor of 0.65 has been assumed to remain constant throughout the next 30 years. The energy intensities (fuel use/vehicle-km) of intercity car, bus, train and airplane have been assumed to decline by 10% by the year 2022–23. Table 4.10 shows the base year and projected intercity passenger transportation activity levels, shares by mode and energy intensities. It may be noted that due to the assumption of declining load factors the energy intensity (kW·h/passenger-km) for car, bus and train remains essentially constant.

Table 4.10. Activity Levels and Energy Intensities in Intercity Passenger Transportation (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Total activity (10^9 passenger-km)	154.627	210.515	319.080	532.239
Share by mode (%)				
Car	6.1	10.7	16.4	22.1
Bus	81.2	76.1	70.4	64.8
Train	11.0	10.7	10.0	9.3
Steam	(4.2)	(1.0)	(0)	(0)
Diesel	(91.8)	(93.0)	(89.0)	(82.0)
Electric	(4.0)	(6.0)	(11.0)	(18.0)
Plane	1.6	2.5	3.2	3.7
Energy intensity (kW·h/passenger-				
km)	0.322	0.321	0.322	0.322
Car	(3.0)	(2.9)	(2.8)	(2.7)
(Passengers/car)				
	0.080	0.080	0.080	0.081
Bus	(43.7)	(42.1)	(40.5)	(39.0)
(Passengers/bus)				
Train	(507)	(489)	(471)	(455)
(Passengers/train)	0.750	0.751	0.753	0.752
Steam	0.084	0.084	0.085	0.084
Diesel	0.030	0.030	0.030	0.030
Electric				
	1.159	1.120	1.082	1.047
Plane	(0.65)	(0.65)	(0.65)	(0.65)
(% of seats occupied)				

4.3.1.3.3. Urban passenger transport

The urban passenger transport activity level is related to the size of population living in large cities, city size, disposable income of the city dwellers and social factors. Based on estimates of activity levels during the period 1986–1993 a growth rate of 1% p.a. has been assumed for the value of average daily travel distance per person in large cities (DU), leading to the urban passenger-km (PKM) in the year 2022–23 being four times the base year level.

It has been judgmentally assumed that the share of "Effective Cars" in urban passenger transport will increase from 35% in the base year to 45% by the year 2022–23. The recently established Mass Transit Authority plans to build mass transit systems in Karachi, Lahore, Faisalabad and Islamabad/Rawalpindi. It is thus expected that some electricity based mass transit systems (such as electric railways and/or electric trams) will be established in future. A share of 10% has been judgmentally assigned to electric mass transit systems in 2022–23. The energy intensity (fuel use/vehicle-km) of "Effective Urban Cars" and "Effective Urban Buses" is assumed to decline gradually from the base year values by 10% by the year 2022–23. Table 4.11 shows the base year and projected urban passenger transportation activity levels, shares by mode and energy intensities (in kW·h/passenger-km).

Table 4.11. Activity Levels and Energy Intensities in Urban Passenger Transportation (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Total activity (10^9 passenger-km)	64.681	112.596	179.948	269.132
Share by mode (%)				
Car	35.3	38.5	41.7	45.0
Motor fuel	(100.0)	(100.0)	(100.0)	(100.0)
Mass transit	64.7	61.5	58.3	55.0
Motor fuel	(100.0)	(99.0)	(96.0)	(90.0)
Electric	(0.0)	(1.0)	(4.0)	(10.0)
Energy intensity (kW·h/passenger-km)				
Car	(2.80)	(2.70)	(2.60)	(2.52)
(Passengers/car)	0.411	0.411	0.412	0.411
Motor fuel				
Mass transit	0.076	0.076	0.076	0.076
Motor fuel	(54.8)	(53.0)	(51.2)	(49.36)
(Passengers/bus)	0.060	0.060	0.063	0.065
Electric	(58.4)	(56.4)	(54.4)	(52.5)
(Passengers/tram)				

4.3.1.4. Specific energy intensity in household

To project electricity demand in the household sector, the extent of electrification has to be estimated in the first place. At present, only 57% of the total households have access to electricity. However, based on the official target of achieving 100% electrification by 2008 and the observation that when the electric grid is extended to a village it takes a few years for most of the households to get access to electricity, a level of 100% electrification has been assumed in 2012–13.

Air conditioning is a fast growing end-use activity in the household sector. In the base year, only 1.0% households were using air conditioners. It is projected that by the year 2022–23 about 8.5% of the households will be using ACs. The specific electricity consumption (kW·h/dwelling/year) on account of air conditioning has been projected to increase gradually to a level of 2.5 times the base year level, by the year 2022–23. This increase in specific electricity consumption for air conditioning has been assumed to reflect the expected increase in average number of air conditioners per household which is expected with the increase in income per household.

In the base year the specific electricity consumption (kW·h/year/electrified household) in the households for lighting , air cooling and other appliances has been estimated as 458, 418 and 453 respectively, giving a total consumption of 1329. The projection of these three end-uses separately, by assuming certain growth rates due to income effects and reduction in intensities due to technological improvements, and their summation show that the energy intensity of electrical appliances will almost double during the next 30 years.

For non-electric energy consumption in households, the end-use categories considered are cooking, water heating and space heating. The energy intensity of cooking has been projected to increase by about 12% over the 30 years period.

As for water heating, it has been assumed that all urban households use this facility. As such, the fraction of households using water heating has been taken as the urban fraction of total number of households. The specific energy consumption for water heating has been increased in proportion to increase in the GDP per capita. During the 30 years study period, the energy intensity for this end-use increase by a factor of 3.6.

The MAED parameters related to space heating activity include specification of type of old and new dwellings. The present stock of dwellings as well as the new dwellings have been assumed to be of single family units type. Mostly natural gas is used for space heating. It has been estimated that only about 2% of the existing households used space heating in the base year. This share has been assumed to increase in future in line with the expected increase in gas connections. For new housing units, it has been assumed that initially 10% will be using space heating and this share will increase to 40% by the end of planning horizon.

The specific energy requirement for space heating, in useful energy terms, has been estimated as 2170 kW·h per year per household for the base year. This has been assumed to remain constant for pre-1993 buildings even for future years. For the post-1993 dwellings, lower and declining intensities have been assumed. Table 4.12 gives the assumptions of penetration of space heating, hot water, electrification and air conditioning in households while Table 4.13 gives the base year and projected energy intensities of the same end-uses.

The end-use efficiencies of fossil fuels for cooking, water heating and space heating for the base year (60%) have been worked out from HESS estimates for individual fossil fuels and have been projected to improve by a factor of 1.1 by the terminal year. However, the end-use efficiency of non-commercial fuels has been assumed to increase from the base year value of 13% to 16% by the end of the planning horizon, in view of the efforts being made for introduction of improved cook stoves. The use of non-commercial fuels has been assumed to slightly increase with time in line with the estimates of the Planning Commission [62].

As for the penetration of electricity for different thermal uses in households, the fact is that, natural gas, if available, is the most preferred fuel. Further, the Government is planning to provide natural gas to even small towns. As such, the use of electricity for water heating has been projected to be minimal, while that for cooking has been kept zero. However, it has been assumed that the share of electricity in space heating activity will increase gradually from the base year value of 5% to about 10% by 2022–23. Table 4.14 gives the assumptions about penetration of electricity into thermal uses for household and service sectors.

Table 4.12. Households with Space Heating, Hot Water , Electricity and Air conditioners

	1992–93	2002–03	2012–13	2022–23
Persons/Household	7.190	6.990	6.793	6.600
Dwellings (Million)	16.806	22.696	28.960	35.540
A. of which in area requiring heating	100.0%	100.0%	100.0%	100.0%
Constructed before base year (million)	16.806	14.594	9.714	1.119
	100%	64.3%	33.5%	3.1%
Room Heating (million)	0.354	1.022	1.554	0.336
	(2.1%)	(7.0%)	(16.0%)	(30.0%)
No Heating (million)	16.452	13.572	8.160	0.784
	(97.9%)	(93.0)	(84.0%)	(70.0%)
Constructed after base year (million)	0.0	8.102	19.246	34.420
		35.7%	66.5%	96.9%
Room Heating (million)	0.0	1.257	5.201	13.605
		(15.5%)	(27.0%)	(39.5%)
No Heating (million)	0.0	6.844	14.045	20.815
		(84.5%)	(73.0%)	(60.5%)
B. of which with hot water	31.5%	35.4%	38.8%	41.4%
C. of which electrified	56.8%	75.5%	100%	100%
D. of which with Air conditioners	1.0%	2.0%	4.0%	8.5%

Table 4.13. Energy Intensity (Useful) Assumed for the Household Sector (Reference Scenario)

(kW·h/dwelling/year)

	1992–93	2002–03	2012–13	2022–23
Space heating:				
Constructed before base year				
Room heating	2170	2170	2170	2170
Constructed after base year				
Room heating	0	1670	1436	1201
Water heating	367	535	824	1321
Cooking	2402	2523	2615	2687
Air conditioning	5119	7643	10 348	12 693
Electrical appliances (final)	1329	1620	2016	2616

4.3.1.5. Specific energy intensity in Service sector

For the Service sector, energy and electricity consumption are projected on the basis of floor area in the service sector and the specific consumption for each end-use. It has been projected that the total floor area in the service sector will increase from about 104.9 million sq.m in the base year to 340.1 million sq.m by the year 2022–23. For the base year, it has been estimated that only 5% of the total area has air conditioning and about 50% has heating facilities. These fractions have been projected to increase with time to 26.9% and 65%, respectively by the terminal year of the study.

The heating activity, in fact, includes other thermal uses in this sector such as hot water and cooking in restaurants, etc. The specific energy consumption for this activity has been estimated as 74 kW·h/sq.m/year for the pre-1993 buildings and assumed as 75.6 kW·h/sq. m/year for the new buildings.

The specific electricity consumption (useful) for air-conditioning has been estimated as 352 kW·h/sq.m/year in the base year increasing to 387 kW·h/sq. m/year by the year 2022–23. The electricity consumption for other appliances in the pre-1993 floor area of the service sector has been estimated as 33 kW·h/sq.m/year. The electricity consumption for lighting is the major component of this activity in the service sector. The average efficiency of lighting equipment will increase with time resulting in relatively lower specific electricity consumption. However, in view of expected increased use of office equipment and other electrical appliances in future, the specific electricity consumption for other appliances has been assumed to increase slightly from 33 kW·h/sq.m/year to 39 kW·h/sq.m/year in the old buildings and from 41 kW·h/sq.m/year to 45 kW·h/sq.m/year in the new buildings, by the year 2022–23. Tables 4.14 and 4.15 list the base year and projected values of specific electricity consumption, electricity penetration into thermal uses and specific consumption of space/water heating and air conditioning.

4.3.2. Optimistic and Constrained Scenarios

The Optimistic and Constrained Scenarios differ from the Reference Scenario in the level of economic growth and mix of economy with all the three scenarios envisaging similar levels of energy efficiency improvements. The impact of higher or lower economic growth and different mix of economy on energy demand for various sectors is briefly described below.

4.3.2.1. Manufacturing sector

In the Optimistic scenario the structure of the Manufacturing sector has been assumed to change gradually in such a way that by the year 2022–23 the share of Basic materials and Machinery and equipment industries are higher by about 3 percentage points and 2 percentage points respectively, while the shares of consumer goods and small scale industries are lower by about 3 percentage points and 2 percentage points, respectively, than in the Reference Scenario. As a result, the final energy intensity of Manufacturing sector for the Optimistic and Reference Scenarios are different, in spite of the assumption of identical change in intensities for the two scenarios. Table 4.16 gives a comparison of the total final energy intensities of the Manufacturing sector for the Reference, Optimistic and Constrained Scenarios, along with the Energy Efficiency Scenario (discussed in Section 4.3.3).

4.3.2.2. Transport sector

Different levels of GDP and per capita GDP in the three scenarios result in significant differences in the values of various parameters of the Transport sector, such as freight activity, intercity and intracity passenger activity and population of cars, which in turn determine energy demand of this sector (see Table 4.17). The values of these parameters vary by a factor of more than 2 between the Constrained and the Optimistic Scenarios.

Table 4.14. Electricity Penetration in Household and Service Sectors (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Households				
Specific electricity consumption in:				
- Dwellings for uses other than space/water heating, cooking and A.C. (kW·h/dwelling/year)	1329	1620	2016	2616
Electricity penetration into thermal uses for:				
- Space heating	0.050	0.063	0.080	0.100
- Water heating	0.000	0.002	0.007	0.020
- Cooking	0.000	0.000	0.000	0.000
Services				
Specific electricity consumption in:				
- Old service sector buildings (kW·h/year/sqm)	33	35	37	39
- New service sector buildings (kW·h/year/sqm)	0	41	43	45
Electricity penetration for:				
- Thermal uses	0.060	0.072	0.090	0.115

Table 4.15. Energy Intensities Assumed for the Service Sector (Reference Scenario)

	1992–93	2002–03	2012–13	2022–23
Space and water heating (useful; kW·h/sqm/year)				
Buildings constructed before base year	74.0	74.0	74.0	74.0
Buildings constructed after base year	0.0	75.6	75.6	75.6
Air conditioning; Specific consumption (useful; kW·h/sqm/year)	352	364	375	387

Table 4.16. Comparison of Final Energy Intensities of Manufacturing in the Four Energy Demand Scenarios

[kW·h/10³ Rs.]

Scenario	1992–93	2002–03	2012–13	2022–23
Reference	608	549	505	480
Optimistic	608	552	525	499
Constrained	608	542	497	460
Energy efficiency	608	465	390	346

Table 4.17. Principal Determining Factors of Energy Demand of the Transport Sector

	1992–93	2002–03	2012–13	2022–23
Freight Activity [10^9 ton-km]				
Reference Scenario	52.673	79.017	131.626	241.422
Optimistic Scenario	52.673	81.823	164.281	370.759
Constrained Scenario	52.673	76.471	112.445	170.695
Energy Efficiency Scenario	52.673	79.017	131.626	241.422
Passenger Mobility Intercity [10^9 p-km]				
Reference Scenario	154.627	210.515	319.080	532.239
Optimistic Scenario	154.627	220.668	402.489	808.328
Constrained Scenario	154.627	200.997	262.818	367.337
Energy Efficiency Scenario	154.627	210.515	319.080	532.239
Passenger Mobility Urban [10^9 p-km]				
Reference Scenario	64.681	112.596	179.948	269.132
Optimistic Scenario	64.681	122.050	245.286	461.481
Constrained Scenario	64.681	105.744	140.593	172.007
Energy Efficiency Scenario	64.681	112.596	179.948	269.132
Population of "Effective Cars" (Million)				
Reference Scenario	1.052	2.364	5.150	10.860
Optimistic Scenario	1.052	2.473	6.431	16.755
Constrained Scenario	1.052	2.253	4.199	7.616
Energy Efficiency Scenario	1.052	2.364	5.150	10.860

4.3.2.3. Household and Service sectors

The major differences among the Reference, Optimistic and Constrained scenarios having impacts on energy demand are:

- In the Optimistic Scenario the share of urban population has been assumed to be the highest (44%) compared to 40% in the Constrained Scenario, in the year 2022–23,

- 100% electrification of households has been envisaged by the year 2002–03 in the Optimistic Scenario compared to 2012–13 in the Constrained Scenario,

- The electricity consumption per electrified household (kW·h/dwelling/year) for appliances (excluding ACs) in the year 2022–23 for the Optimistic, Reference and Constrained Scenarios are 3480, 2616 and 2117, showing a variation by a factor of 1.64,

- Share of dwellings with ACs has been assumed as 15.3% in the Optimistic Scenario, compared to the assumption of 4.7% in the Constrained Scenario, in the year 2022–23, in relation to a share of 1.0% in the base year,

- The average floor area per employee (m^2/employee) in the service sector has been assumed as 16 in the Optimistic Scenario compared to 13 in the Constrained Scenario, in the year 2022–23,

- Share of service sector floor area air conditioned has been assumed as 39% in the Optimistic Scenario compared to 19% in the Constrained Scenario, by the year 2022–23,

- Share of service sector floor area actually heated has been assumed as 70% in the Optimistic Scenario compared to 60% in the Constrained Scenario, in the year 2022–23.

4.3.3. Energy Efficiency Scenario

ENERCON has estimated that 5–40% energy savings are possible in various sectors [63] if vigorous efforts are made by the government through awareness campaigns, regulations and pricing measures. The energy intensity and efficiency levels envisaged in the Energy Efficiency Scenario are described in this section along with their comparison with the Reference scenario.

4.3.3.1. Agriculture sector

A comparison of efficiency of diesel pumps, electric tubewells and fuel consumption per tractor per hour for Energy Efficiency Scenario with the Reference Scenario is given in Table 4.18. The efficiency of diesel and electric tubewells have been assumed to be some 4 percentage points and 8 percentage points higher in the Energy Efficiency Scenario compared to the Reference Scenario, in the year 2022–23. Similarly the fuel use per tractor per hour has been assumed to be 18% lower in the Energy Efficiency Scenario compared to the Reference Scenario, in the year 2022–23

4.3.3.2. Manufacturing sector

A comparison of assumptions of change in energy intensity of Manufacturing sector in the four scenarios is given in Table 4.19. It may be noted that for the Energy Efficiency Scenario, the intensity of electricity, after increasing in the initial years, gradually declines and has been assumed to be lower in the terminal year as compared to the base year. Average efficiency of fossil fuel use for thermal processes in Manufacturing sector has been assumed to be 85% in Energy Efficiency Scenario compared to 72.5% in the Reference Scenario in the year 2022–23. Further, in the Energy Efficiency Scenario the use of co-generation systems, has been assumed to be larger and with higher efficiencies compared to the Reference Scenario.

Table 4.18. Comparison of Energy Efficiency and Intensity Assumptions in Reference Scenario and Energy Efficiency Scenario for the Agriculture Sector

	1992–93	2002–03	2012–13	2022–23
1. Efficiency of diesel pumps [%]				
Reference scenario	7.2	8.5	9.4	10.0
Energy Efficiency scenario	7.2	9.9	12.2	14.0
2. Efficiency of electric pumps [%]				
Reference scenario	27.0	31.0	33.0	35.0
Energy Efficiency scenario	27.0	34.4	39.8	43.0
3. Intensity of fuel use in tractors [Litres/tractor-hour]				
Reference scenario	5.0	4.83	4.67	4.50
Energy Efficiency scenario	5.0	4.56	4.13	3.69

Table 4.19. Change in Energy Intensity Assumptions for the Manufacturing Sector

	1992–93	2002–03	2012–13	2022–23
Motor Fuels				
All Scenarios	1.0	1.0	1.0	1.0
Thermal Uses				
Reference/Optimistic & Constrained Scenarios	1.0	0.870	0.787	0.750
Energy Efficiency Scenario	1.0	0.798	0.682	0.600
Electricity				
Reference/Optimistic & Constrained Scenarios	1.0	1.093	1.138	1.150
Energy Efficiency Scenario	1.0	1.047	1.024	0.978

4.3.3.3. Transport sector

A comparison of the assumptions of energy intensities of the Transport sector in the Reference and Energy Efficiency scenarios is given in Table 4.20. It may be noted that for road freight transport, a reduction of about 21% has been envisaged in the year 2022–23, in the fuel use per ton-km in the Energy Efficiency Scenario, compared to the Reference Scenario. For road passenger transport about 17% reduction has been assumed for buses and 28% for cars in Energy Efficiency Scenario compared to the Reference Scenario in the terminal year of the study. For trains an efficiency improvement of 5% by the year 2022–23 has been assumed compared to the Reference Scenario. For oil pipelines, no change in intensity has been envisaged in the Energy Efficiency Scenario compared to the Reference Scenario. The envisaged increase in intensity of pipeline with time is due to the assumption that share of crude oil and furnace oil pipelines will increase with time.

Table 4.20. Comparison of Energy Intensity of Transport Sector in Reference and Energy Efficiency Scenario

	1992–93	2022–03	2012–13	2022–23
Freight Transportation (kcal/ton-km)				
Reference scenario				
Long Distance Truck	523.54	506	488	470
Local Truck	877.42	848	818	790
Diesel Train	90	87	84	81
Pipelines	30.77	32.2	33.6	35
Energy Efficiency scenario				
Long Distance Truck	523.54	456	404	370
Local Truck	877.42	840	794	751
Diesel Train	90	86	82	77
Pipelines	30.77	32.2	33.6	35
Passenger Transportation (kcal/pass-km)				
Reference scenario				
Intercity Bus	68.6	68.6	68.7	69.2
Urban Bus	65.6	65.6	65.6	65.6
Intercity Car	276.7	276.7	276.7	276.7
Urban Car	353	353	353	353
Train	72.4	72.6	72.6	72.6
Plane	996.9	963.1	930.8	900
Energy Efficiency scenario				
Intercity Bus	68.6	64.6	60.7	57.7
Urban Bus	65.6	61.6	58.0	54.7
Intercity Car	276.7	248.3	222.5	199.9
Urban Car	353.3	319.9	287.9	255.0
Train	72.4	71.8	70.6	69.0
Plane	996.9	790.8	604.6	438.5

4.3.3.4. Household and Service sectors

The energy intensities of the Household sector assumed for the Energy Efficiency Scenario are given in Table 4.21. This Table also gives values of reduction with respect to the Reference scenario. In addition to the reduction in energy intensities the efficiency of use of fossil fuels has also been assumed to improve by 4% in the Energy Efficiency Scenario, compared to the Reference Scenario value of 66% in the year 2022–23.

In the Service sector, the specific electricity consumption in ACs (useful, kW·h/sq. m/year) has been assumed as 214 which is about 45% lower compared to the value of 387 for the Reference Scenario, in the year 2022–23. Specific use of electricity (kW·h/sq. m/year), in the year 2022–23, has been assumed as 31 and 36 in the Energy Efficiency Scenario compared to 39 and 45 in the Reference Scenario for buildings constructed before 1992–93 and after 1992–93, respectively.

Table 4.21. Energy Intensity (Useful) assumed for the Household Sector (Energy Efficiency Scenario)

(kW·h/dwelling/year)

	1992–93	2002–03	2012–13	2022–23
Space heating:				
Constructed before base year				
Room heating	2170	2170	2170	2170
Reduction w.r.t. Reference Scenario	-	-	-	-
Constructed after base year				
Room heating	0	1612	1319	1026
Reduction w.r.t. Reference Scenario	-	3.5%	8.1%	14.6%
Water heating	367	535	824	1321
Reduction w.r.t. Reference Scenario	-	-	-	-
Cooking	2402	2454	2500	2539
Reduction w.r.t. Reference Scenario	-	2.7%	4.4%	5.5%
Air conditioning	5119	7388	9658	11424
Reduction w.r.t. Reference Scenario	-	3.3%	6.7%	10.0%
Electrical appliances (final)	1329	1569	1829	2243
Reduction w.r.t. Reference Scenario	-	3.1%	9.3%	14.3%

4.4. Energy and Electricity Demand Projections

4.4.1. Analysis of Total and Per Capita Final Energy Demand

The key determinants of future energy demand are the levels of total population and GDP. The total population level has been assumed as 235 million in 2022–23, which is 94% higher as compared to the base year. The average GDP growth rate in the Reference and Energy Efficiency Scenarios has been assumed as 7% p.a., in the Optimistic Scenario as 8.5% p.a. and in the Constrained Scenario as 5.7% p.a. Table 4.22 and Fig. 4.3. describe the evolution of GDP in various scenarios.

In the base year some 20.3 million TOE of non-commercial fuels were used (18.2 million TOE in Households and 2.1 million TOE of bagasse in the Manufacturing sector). The use of non-commercial fuels has been projected to reach a level of 38.0 million TOE (30.6 million TOE in Households and 7.4 million TOE in Manufacturing), in the Reference Scenario by the year 2022–23. The level of non-commercial fuel use in Households in all the scenarios has been considered to be the same. However, the level of bagasse use in 2022–23, varies between 7.1–9.5 million TOE, depending upon the envisaged level of value added of the Agriculture sector.

Table 4.22. GDP Evolution for the Four Scenarios

Year	Total GDP (10^9 Rs. of 1992–93)				Growth Rate[(1)] [% p.a.]			
	Reference Scenario	Optimistic Scenario	Constrained Scenario	Energy Efficiency Scenario	Reference Scenario	Optimistic Scenario	Constrained Scenario	Energy Efficiency Scenario
1992–93	1200.5	1200.5	1200.5	1200.5	–	–	–	–
1997–98	1682.3	1682.3	1682.3	1682.3	6.98	6.98	6.98	6.98
2002–03	2358.2	2472.2	2252.3	2358.2	6.99	8.00	6.01	6.99
2007–08	3307.1	3803.6	2944.0	3307.1	7.00	9.00	5.50	7.00
2012–13	4638.0	5849.3	3819.5	4638.0	7.00	8.99	5.34	7.00
2017–18	6505.5	9006.3	4935.2	6505.5	7.00	9.02	5.26	7.00
2022–23	9123.8	13 855.2	6297.8	9123.8	7.00	9.00	5.00	7.00
1993 to 2023					7.00	8.49	5.68	7.00

(1) Average annual growth rate during the past five years

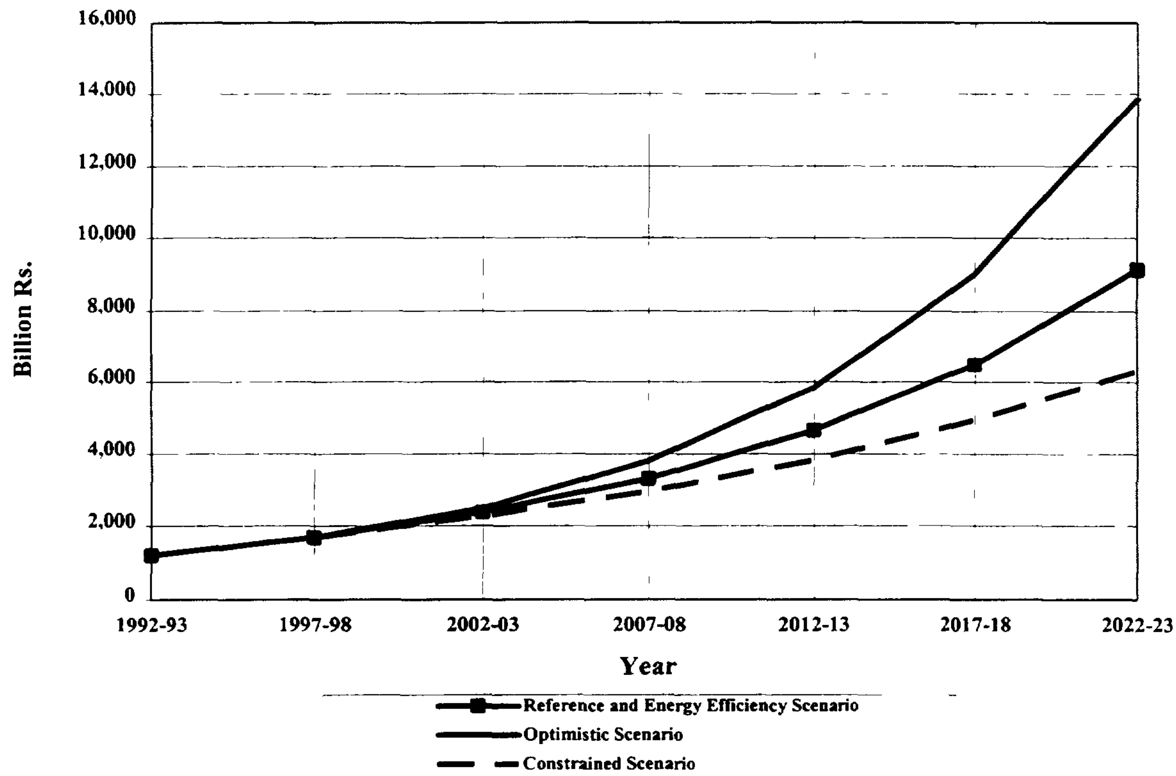


FIG. 4.3. Trends in GDP Formation

The total final energy requirements of commercial energy have been projected as: 169 million TOE in the Reference Scenario, 294 million TOE in the Optimistic Scenario, 100 million TOE in the Constrained Scenario and 125 million TOE in the Energy Efficiency Scenario (see Fig. 4.4. and Table 4.23). Appendix C gives the results of Module 1 of the MAED model for the Reference Scenario. It may be noted that commercial final energy demand in the Optimistic Scenario is about 74% higher, in the terminal year, than the Reference Scenario demand, whereas it is 41% lower in the Constrained Scenario compared to the Reference Scenario. In both cases, the growth in economy is the main reason for this variation in energy demand. In the case of the Energy Efficiency Scenario, which has the same level of economic growth as in the Reference Scenario, the commercial final energy demand in the terminal year is about 26% lower compared to that in the Reference Scenario, because of various energy conservation and efficiency improvement measures assumed in this scenario.

Table 4.23. Total Commercial Final Energy Demand and Average Growth Rates

	1992–93	2002–03	2012–13	2022–23
Energy Uses [MTOE]				
Reference Scenario	20.175	38.626	76.902	155.474
Optimistic Scenario	20.175	41.301	107.198	272.052
Constrained Scenario	20.175	35.826	57.905	90 368
Energy Efficiency Scenario	20.175	33.624	60.699	113 675
Non-Energy Uses* [MTOE]				
Reference Scenario	2.450	5.126	8.327	13.413
Optimistic Scenario	2.450	5.356	10.782	21.584
Constrained Scenario	2.450	4.935	7.128	9 316
Energy Efficiency Scenario	2.450	4.995	7.756	11 477
Total Commercial Final Energy [MTOE]				
Reference Scenario	22.625	43.752	85.229	168.887
Optimistic Scenario	22.625	46.657	117.980	293.636
Constrained Scenario	22.625	40.761	65.033	99 684
Energy Efficiency Scenario	22.625	38.619	68.455	125.152
Total Commercial Final Energy Growth Rate [% p.a.]	1993–2003	2003–2013	2013–2023	1993–2023
Reference Scenario	6.82	6 90	7.08	6.93
Optimistic Scenario	7.51	9 72	9.55	8.92
Constrained Scenario	6.06	4 78	4.36	5.07
Energy Efficiency Scenario	5.49	5.89	6.22	5.87

* Includes coke, fertilizer feedstocks and non-energy oil uses

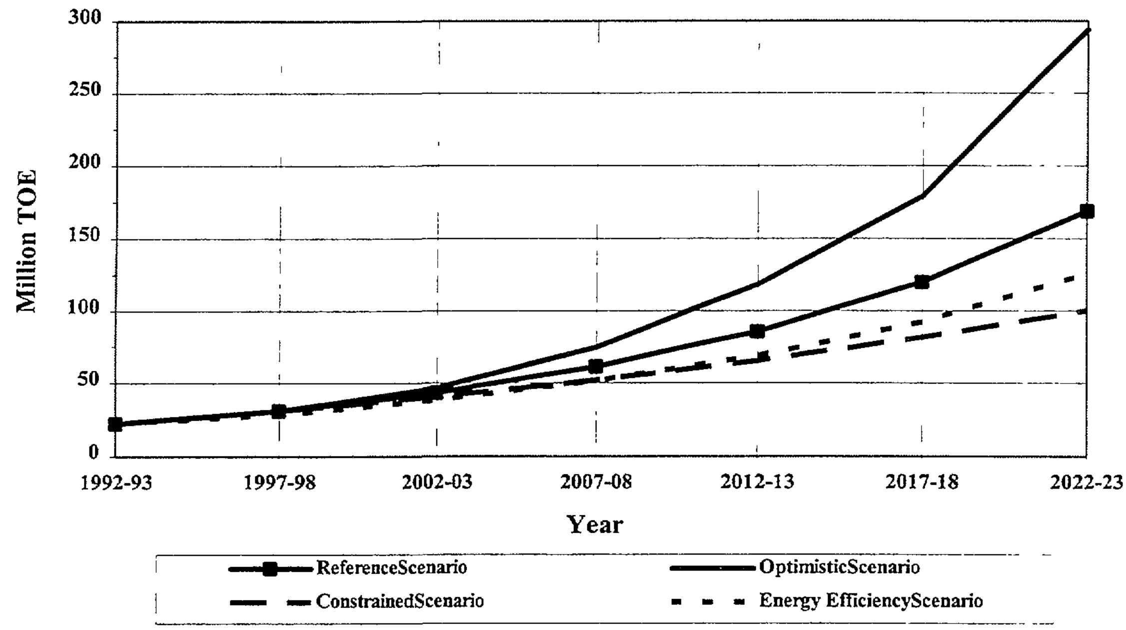


FIG. 4.4. Trends in Demand of Final Energy

According to these projections, the per capita commercial final energy demand will increase over the 30 years; by a factor of 3.8 in the Reference Scenario; by a factor of 6.6 in the Optimistic Scenario; by a factor of 2.2 in the Constrained Scenario and by a factor of 2.8 in the Energy Efficiency Scenario (see Table 4.24). These projections indicate that, considering the Reference Scenario, even after three decades the per capita commercial final energy demand will be slightly higher than the present consumption of Thailand and lower than the present consumption of Malaysia (see Fig. 4.5.). The per capita GDP will be lower than that of present day Thailand.

Table 4.24. Trends of Per Capita Commercial Final Energy* Consumption and GDP in various Scenarios

Year	Commercial Final Energy Per Capita [TOE/capita]				GDP Per Capita [Rs of 1992–93/capita]			
	Reference Scenario	Optimistic Scenario	Constrained Scenario	Energy Efficiency Scenario	Reference Scenario	Optimistic Scenario	Constrained Scenario	Energy Efficiency Scenario
1992–93	0.19	0.19	0.19	0.19	9935	9935	9935	9935
2002–03	0.28	0.29	0.26	0.24	14 865	15 584	14 197	14 865
2012–13	0.43	0.60	0.33	0.35	23 577	29 734	19 416	23 577
2022–23	0.72	1.25	0.42	0.53	38 896	59 067	26 848	38 896

* Includes coke, fertilizer feedstocks and non-energy oil uses.

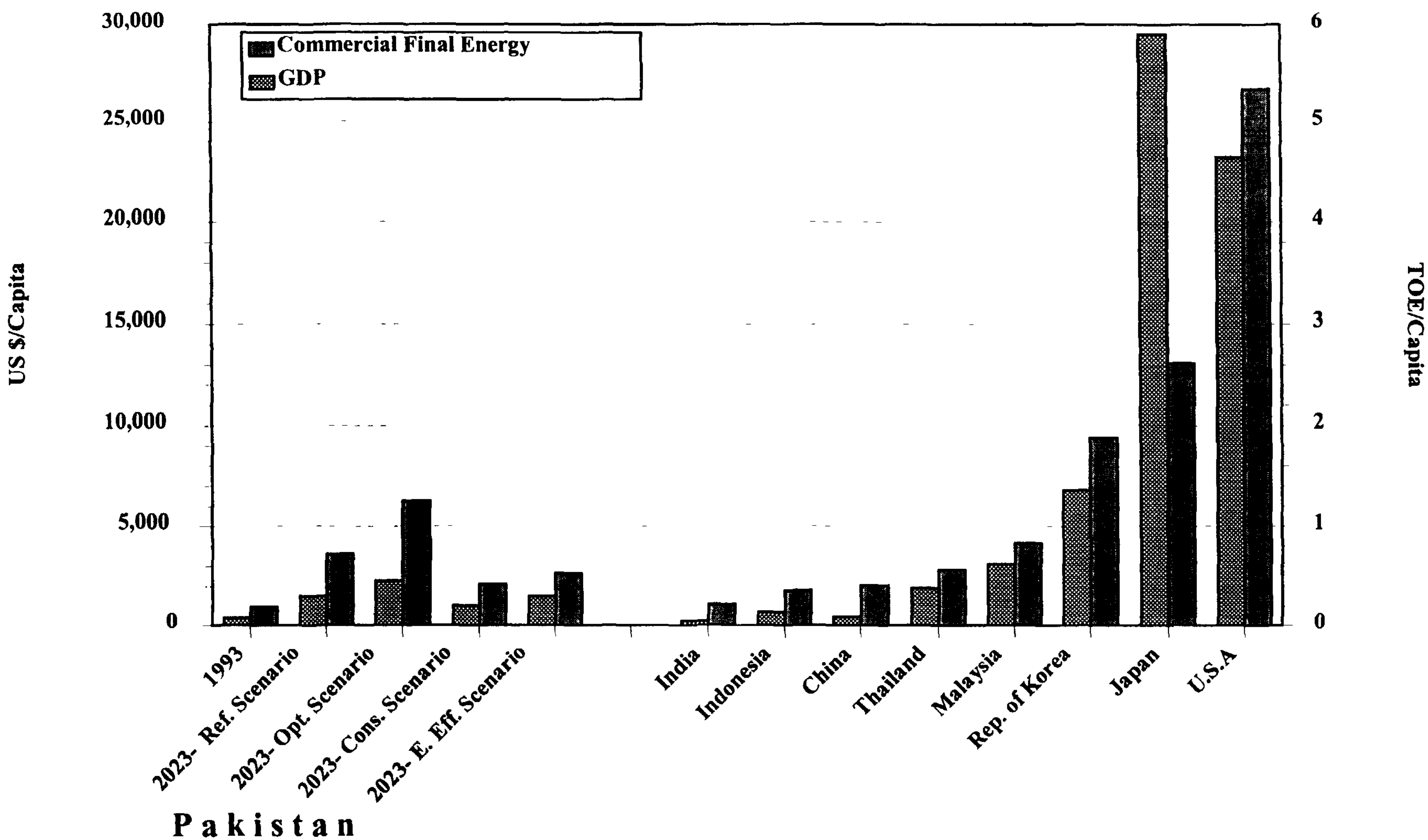


FIG. 4.5. Comparison of GDP Per Capita and Final Energy Per Capita of Pakistan with some Selected Countries

Note: Data for countries other than Pakistan corresponds to 1992.

Table 4.25. Income Elasticity of Commercial Final Energy Demand*

	1993–2003	2003–2013	2013–2023	1993–2023
Growth Rates of Final Commercial Energy Demand [% p.a.]				
Reference Scenario	6.7	7.1	7.3	7.0
Optimistic Scenario	7.4	10.0	9.8	9.1
Constrained Scenario	5.9	4.9	4.6	5.1
Energy Efficiency Scenario	5.2	6.1	6.5	5.9
GDP Growth Rates [% p.a.]				
Reference Scenario	7.0	7.0	7.0	7.0
Optimistic Scenario	7.5	9.0	9.0	8.5
Constrained Scenario	6.5	5.4	5.1	5.7
Energy Efficiency Scenario	7.0	7.0	7.0	7.0
Income Elasticity				
Reference Scenario	0.96	1.02	1.04	1 01
Optimistic Scenario	0.99	1.11	1.08	1.07
Constrained Scenario	0.91	0.91	0.89	0.90
Energy Efficiency Scenario	0.75	0.87	0.93	0.85

* Excludes coke, fertilizer feedstocks and non-energy oil uses

The income elasticity of commercial energy demand (approximated as the ratio of growth rates of energy and GDP) in the Reference Scenario has been estimated to be 0.96 for the 1993–2003 period as compared to the value of 1.14 for the last 10 years (1983–1993). The elasticity is estimated to increase slightly for the later periods. In the Optimistic Scenario, these ratios are 0.99, 1.11 and 1.08 for the periods 1993–2003, 2003–2013 and 2013–23, respectively, whereas in the Constrained Scenario these values are 0.91, 0.91 and 0.89. For the Energy Efficiency Scenario, the income elasticity has been estimated as 0.75, 0.87 and 0.93 (Table 4.25).

4.4.2. Analysis and Comparison of Sectoral Energy Demand

A summary of the commercial final energy demand projections for the 30 year planning period (i.e. growth rates, amounts and shares) by sector for the four scenarios is given in Table 4.26. In addition, Figs 4.6. to 4.9. provide the information about amounts and shares of commercial energy demand at 10 year intervals, by sector for the four scenarios separately. The evolution of final energy demand in different scenarios for individual sectors are compared in the following sections.

Table 4.26. Final Commercial Energy Demand Projections by Sector 1993–2023

	Growth rate [% p.a.]	Amount [MTOE]		Share [%]	
	1993–2023	1992–93	2022–03	1992–93	2022–23
Reference Scenario	7.04	20.175	155.474	100	100
1. Agriculture	1.93	2.208	3.922	10.94	2.52
2. Construction/Mining	11.10	0.145	3.412	0.72	2 19
3. Manufacturing	8.86	8.212	104.714	40.70	67.35
4 Transport	4.71	5.285	21.051	26.20	13.54
5. Household	5.68	3.387	17.750	16.79	11.42
6. Service	5.47	0.936	4.626	4.64	2.98
Optimistic Scenario	9.06	20.175	272.052	100	100
1. Agriculture	2.82	2.208	5.089	10.94	1.87
2. Construction/Mining	11.81	0.145	4.123	0.72	1.52
3. Manufacturing	11.24	8.212	200.418	40.70	73.67
4. Transport	6.31	5.285	33.104	26.20	12.17
5. Household	6.65	3.387	23.391	16.79	8.59
6. Service	6.35	0.936	5.928	4.64	2.18
Constrained Scenario	5.13	20.175	90.368	100	100
1. Agriculture	1.84	2.208	3.812	10.94	4.22
2. Construction/Mining	10.11	0.145	2.606	0.72	2.88
3. Manufacturing	6.31	8.212	51.551	40.70	57.05
4. Transport	3.41	5.285	14.447	26.20	15.99
5. Household	4.93	3.387	14.337	16.79	15.87
6. Service	4.61	0.936	3.615	4.64	4.00
Energy Efficiency Scenario	5.93	20.175	113.675	100	100
1. Agriculture	1.25	2.208	3.203	10.94	2.82
2. Construction/Mining	10.91	0.145	3.238	0.72	2.85
3. Manufacturing	7.59	8.212	73.661	40.70	64.80
4. Transport	3.76	5.285	15.977	26.20	14.05
5. Household	4.89	3.387	14.204	16.79	12.50
6. Service	4.39	0.936	3.392	4.64	2.98

1 TOE = 44.2 Giga Joules

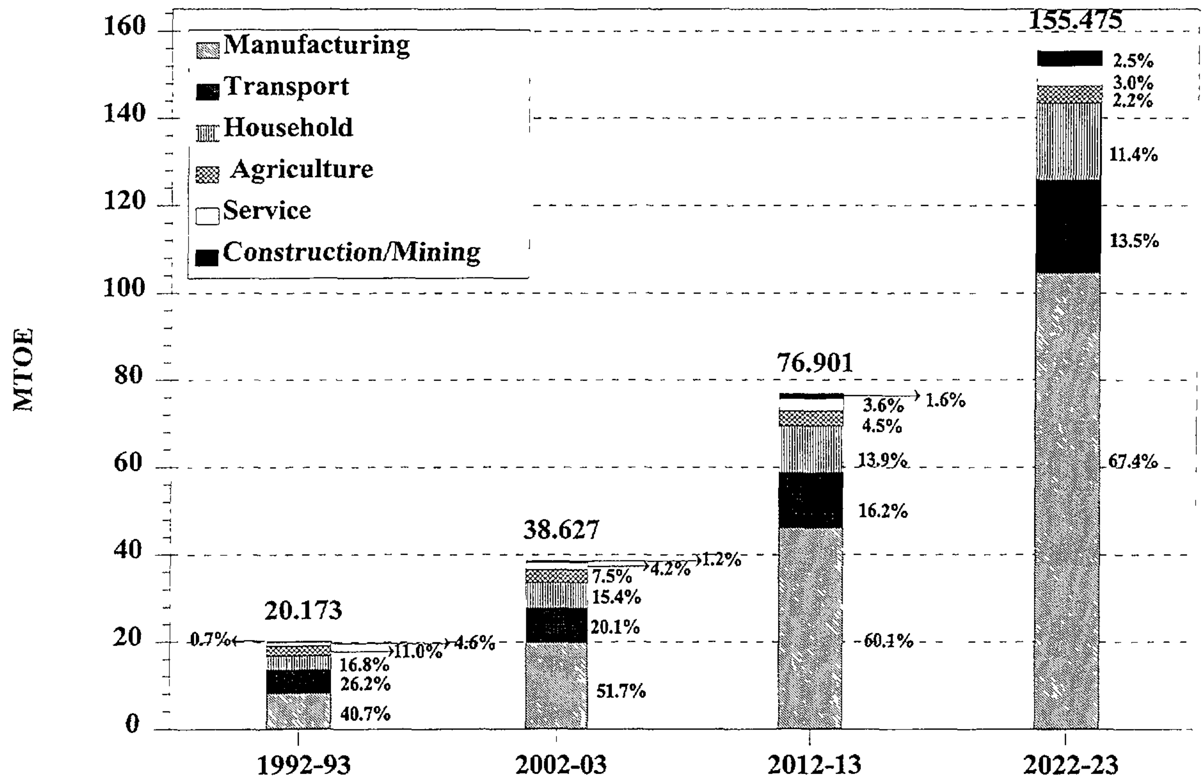


FIG. 4.6. Commercial Final Energy Demand by Sector (Reference Scenario)

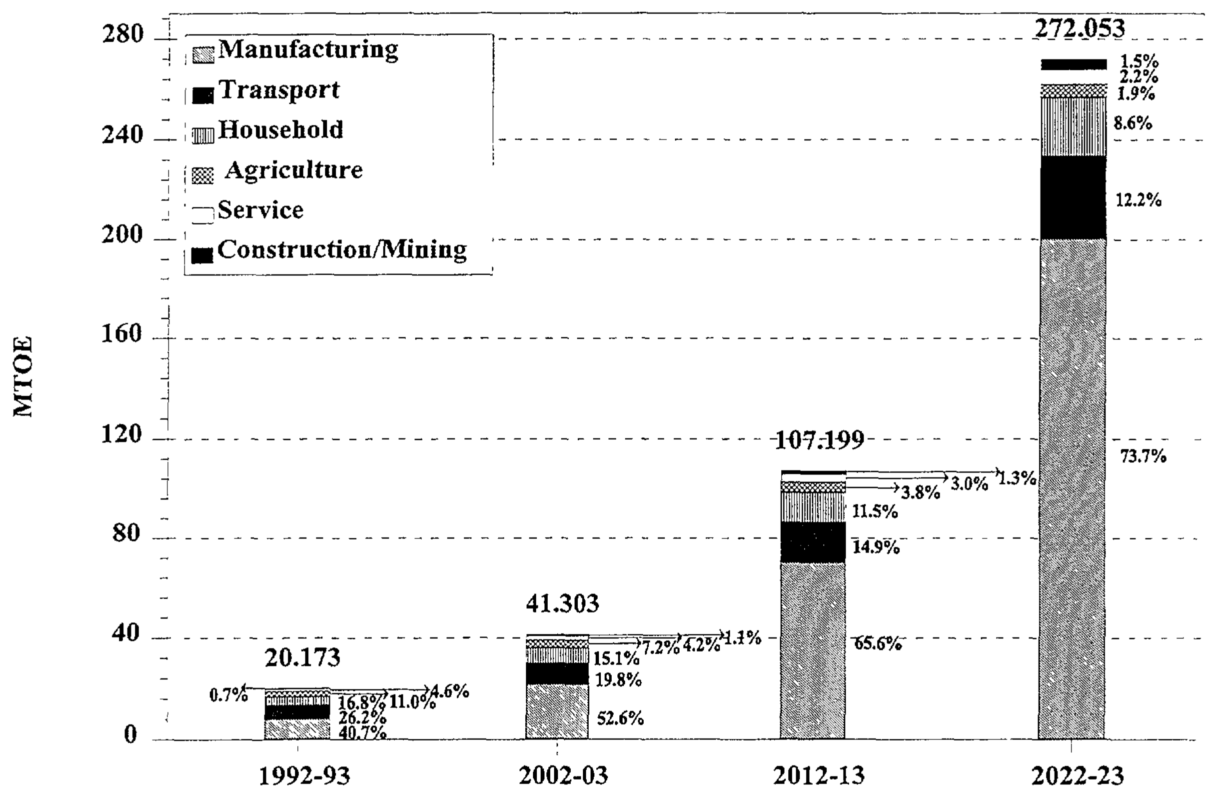


FIG. 4.7. Commercial Final Energy Demand by Sector (Optimistic Scenario)

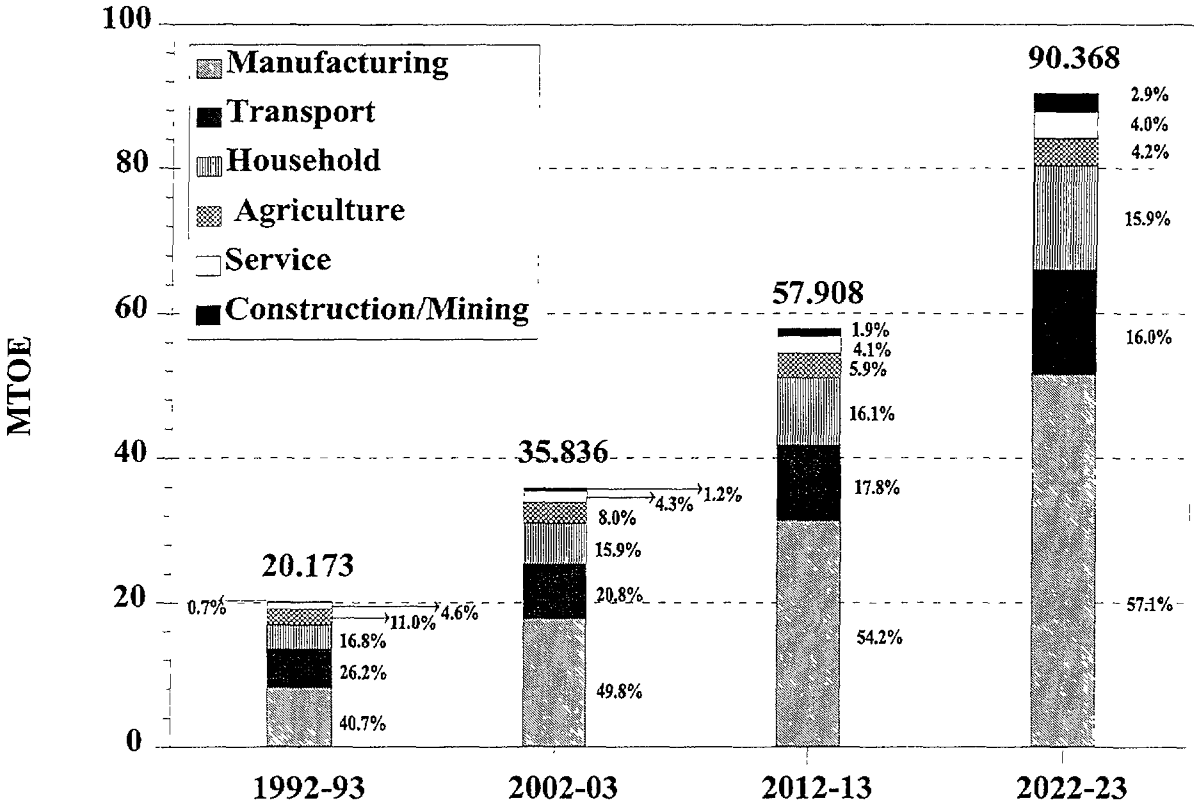


FIG. 4.8. Commercial Final Energy Demand by Sector (Constrained Scenario)

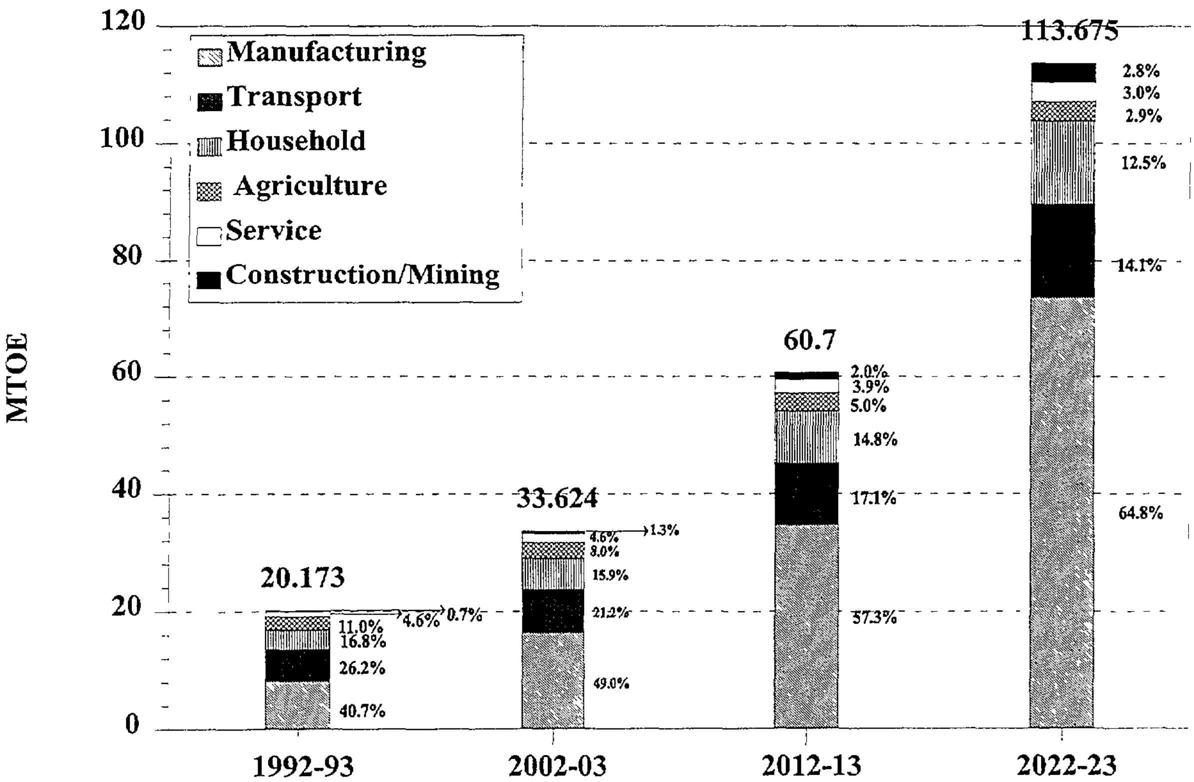


FIG. 4.9. Commercial Final Energy Demand by Sector (Energy Efficiency Scenario)

4.4.2.1. Agriculture sector

In this sector the main activities responsible for energy demand are ground water pumping and use of farm machinery. In the base year this sector had an energy consumption of 2.2 million TOE and a share of 11%. The energy demand growth rates in this sector are the lowest of all sectors primarily due to the assumptions of: (i) tractor population per thousand acres of arable land increasing only by a factor of 2.5 over the planning period and (ii) water availability per irrigated acre, 2.98 feet in 1992–93, reaching a limit of 3.05 feet in the next few years. As a result, the share of the Agriculture sector in the total energy demand reduces to 2–4% by the year 2022–23 in various scenarios.

In the Reference Scenario the growth rate of energy demand for the 1993–2023 period is 1.93% p.a. while the corresponding valued added growth is 4.30%. As such, the elasticity of final energy demand with respect to value added of this sector is 0.45. The elasticities of the Agriculture sector in the case of the Optimistic and Constrained Scenarios for the period 1993–2023 are 0.54 and 0.44, respectively. However in the case of the Energy Efficiency Scenario the elasticity is significantly lower i.e. 0.29.

4.4.2.2. Manufacturing sector

The total commercial final energy demand in this sector has been projected to increase from 8.2 million TOE in 1992–93 to 104.7 million TOE in 2022–23 for the Reference Scenario. The share of the Manufacturing sector in the total final energy demand is projected to increase from 40.7% in the base year to 67.4% in 2022–23. Correspondingly, the income elasticity of final energy is estimated to be 0.97.

As for the other scenarios, the final energy demand in the Optimistic Scenario for this sector will increase to 200.4 million TOE in 2022–23, about 91% higher than that in the Reference Scenario, whereas in the Constrained Scenario this demand will increase to only 51.6 million TOE in 2022–23, about 51% lower than the Reference Scenario. The income elasticity of final energy demand in the Optimistic and Constrained Scenarios are about the same as in the Reference Scenario.

In the Energy Efficiency Scenario, the final energy demand of the Manufacturing sector will be about 30% lower compared to the Reference Scenario due to changes assumed in energy intensities and improvements assumed in the efficiencies of furnaces, boilers and other end-use devices. The elasticity in this scenario is significantly lower (0.83) compared to that for the Reference Scenario.

4.4.2.3. Transport sector

Total final energy demand in the Transport sector in the Reference Scenario has been projected to increase from 5.3 million TOE in 1992–93 to 21.1 million TOE in 2022–23 at an average growth rate of 4.7% per annum. This growth is significantly lower than the overall final energy demand growth rate of 7.0% p.a. Consequently, the share of transport sector in total final energy demand decreases from 26.2% in 1992–93 to 13.5% in 2022–23.

Regarding energy demand for various activities in this sector, the energy requirements for freight transportation have been projected to increase at an average growth rate of 3.9% during the 30 year period while that for passenger transportation have been projected to grow at 5.5% p.a. during the same period. The miscellaneous category has been projected to increase from 0.39 million TOE in the base year to 1.06 million TOE by the terminal year (see Table 4.27)

In the case of the Optimistic Scenario the final energy demand of the Transport sector is higher due to higher economic activity while in the Constrained Scenario it is lower due to reduced economic activity compared to the Reference Scenario. The energy demand in the terminal year is 57% higher in the Optimistic Scenario compared to that in the Reference Scenario whereas it is 31% lower in the Constrained Scenario. In the Energy Efficiency Scenario, as a result of technological improvements and various efficiency improvement measures, the final energy demand of this sector is projected to increase from 5.3 million TOE in 1992–93 to 16.0 million TOE in 2022–23 i.e. 24% lower compared to that in the Reference Scenario.

Table 4.27. Breakdown of the Total Final Energy Demand by Activities in Transport Sector

	Amount [MTOE]		Share [%]	
Scenario/Activity	1992–93	2022–23	1992–93	2022–23
Reference Scenario				
Total	5.285	21.051	100	100
- Freight	2.418	7.702	45.75	36.59
- Passenger	2.477	12.291	46.82	58.39
• Intercity	1.455	7.338	(58.74)	(59.70)
• Urban	1.022	4.953	(41.26)	(40.30)
- Miscellaneous	0.390	1.058	7.38	5.03
Optimistic Scenario				
Total	5.285	33.104	100	100
- Freight	2.418	11.829	45.75	35.73
- Passenger	2.477	19.820	46.82	59.87
• Intercity	1.455	11.326	(58.74)	(57.14)
• Urban	1.022	8.494	(41.26)	(42.86)
- Miscellaneous	0.390	1.456	7.38	4.40
Constrained Scenario				
Total	5.285	14.447	100	100
- Freight	2.418	5.446	45.75	37.69
- Passenger	2.477	8.182	46.82	56.63
• Intercity	1.455	5.016	(58.74)	(61.31)
• Urban	1.022	3.166	(41.26)	(38.69)
- Miscellaneous	0.390	0.820	7.38	5.68
Energy Efficiency Scenario				
Total	5.285	15.977	100	100
- Freight	2.418	6.275	45.75	39.28
- Passenger	2.477	8.644	46.82	54.10
• Intercity	1.455	5.207	(58.74)	(60.24)
• Urban	1.022	3.437	(41.26)	(39.76)
- Miscellaneous	0.390	1.058	7.38	6.62

1 TOE = 44.2 Giga Joules

4.4.2.4. Household and Service sectors

The commercial final energy demand of the Household sector in the Reference Scenario increases from 3.4 million TOE in 1992–93 to 17.8 million TOE in 2022–23. The share of Households in the total final energy demand decrease from 16.8% in 1992–93 to 11.4% in 2022–23. Since most of the parameters influencing energy demand in this sector are directly or indirectly related to income levels, the final energy demand projected for the Optimistic and Constrained Scenarios are correspondingly 32% higher and 19% lower, compared to that for the Reference Scenario. Further, this sector has large potential for energy conservation and efficiency improvements. Considerable part of this potential has been assumed to be realized in the next 30 years in the Energy Efficiency Scenario. As a result, the final energy demand of this sector in this scenario is about 20% lower in the year 2022–23 as compared to that in the Reference Scenario.

A review of energy demand by end-use indicates that share of cooking will decline from 53% in 1992–93 to 36% in 2022–23, in the Reference scenario, while the share of all other end-uses (except kerosene for lighting) will increase (see Table 4.28). By the year 2022–23 the largest end-use will be electricity use in appliances. The decline in the share of cooking end-use and increase in the electricity use in appliances will be even more significant in the Energy Efficiency Scenario as cooking, space heating and water heating have more potential of energy saving compared to electricity use in appliances and air conditioning (see Table 4.29).

The share of Service sector declines from a level of 4.6% in the base year to 2.2–4.0% in the various scenarios due to its slower growth in energy demand compared to other sectors (see Table 4.26).

Table 4.28. Breakdown of the Total Final Energy Demand by End-Use in the Household and Service Sector (Reference Scenario)

	Amount [MTOE]		Share [%]	
Sector/End-Use	1992–93	2022–23	1992–93	2022–23
Household				
Total	3.387	17.750	100	100
- Space Heating	0.031	1.074	0.9	6.1
- Water Heating*	0.085	1.274	2.5	7.2
- Cooking	1.798	6.407	53.1	36.1
- Air Conditioning	0.037	1.425	1.0	8.0
- Appliances	1.033	7.568	30.5	42.6
- Kerosene for lighting	0.402	0	11.9	0
Service				
Total	0.936	4.626	100	100
- Thermal Uses	0.578	2.092	61.8	45.2
- Appliances	0.282	1.223	30.1	26.4
- Air Conditioning	0.075	1.311	8.0	28.3

1 TOE = 44.2 Giga Joules

* Excludes solar energy which has less than 1% share in the year 2023.

Table 4.29. Breakdown of the Total Final Energy Demand by End-Use in the Household and Service Sector (Energy Efficiency Scenario)

Sector/End-Use	Amount [MTOE]		Share [%]	
	1992–93	2022–23	1992–93	2022–23
Household				
Total	3.387	14.204	100	100
- Space Heating	0.031	0.728	0.9	5.1
- Water Heating*	0.085	0.961	2.5	6.8
- Cooking	1.798	4.784	53.1	33.7
- Air Conditioning	0.037	1.230	1.0	8.7
- Appliances	1.038	6.502	30.5	45.8
- Kerosene for lighting	0.402	0	11.9	0
Service				
Total	0.936	3.392	100	100
- Thermal Uses	0.578	1.717	61.8	50.6
- Appliances	0.282	0.980	30.1	28.9
- Air Conditioning	0.075	0.695	8.0	20.5

1 TOE = 44.2 Giga Joules
* Exclude solar energy which has less than 1% share in the year 2023.

4.4.3. Analysis of Final Energy Demand by Energy Form

The amount of non-commercial fuels used in the base year were 20.3 million TOE and by the year 2022–23 these will become 37.7–40.1 million TOE (30.6 million TOE as non-commercial fuels for Households and 7.1–9.5 million TOE as bagasse used by the sugar industry).

The base year figures and projections of the final energy demand by energy form for the four scenarios at ten years intervals are given in the Table 4.30, while Table 4.31 gives a summary of the energy demand projections by energy form. It may be noted from Table 4.31 that in the base year, the shares of fossil fuels (without motor fuels), motor fuels and specific electricity in the commercial final energy were 55%, 32% and 13%, respectively. By the year 2022–23 the share of fossil fuels (without motor fuels) increases to 62% and of motor fuels declines to 17% and the share of electricity increases to 21% in the Reference Scenario. In the Optimistic, Constrained and Energy Efficiency Scenarios, the projected shares of motor fuels are 15%, 21% and 18%, respectively and of electricity are 21%, 22% and 24%, respectively in the year 2022–23.

The growth rates of electricity demand in different scenarios during the period 1993–2023 are: 10.6% p.a. in the Optimistic Scenario, 8.7% p.a. in the Reference Scenario, 8.0% in the Energy Efficiency Scenario and 6.9% p.a. in the Constrained Scenario. Further, the specific electricity demand, in the year 2022–23, will be a factor of 21 in the Optimistic Scenario, 12 in the Reference Scenario, 10 in the Energy Efficiency Scenario and 7 in the Constrained Scenario, as compared to the base year.

Table 4.30. Distribution of Final Energy Demand by Energy Forms

[MTOE]

Scenario/Energy Form	1992–93	2002–03	2012–13	2022–23
Reference Scenario				
- Substitutable fossil fuels*	10.008	20.996	43.393	90.563
- Motor fuels	7.196	10.690	16.923	28.524
- Electricity	2.971	6.939	16.548	36.075
- Soft Solar	0	0.002	0.037	0.312
- Coal, Specific Uses	0.658	1.329	2.856	6.133
- Feedstocks**	1.792	3.797	5.471	7.280
Total Commercial	22.625	43.752	85.229	168.887
Non-commercial	20.309	27.203	33.358	37.996
Optimistic Scenario				
- Substitutable fossil fuels*	10.008	22.689	63.689	167 015
- Motor fuels	7.196	11.198	21.255	43.083
- Electricity	2.971	7.413	22.202	61.402
- Soft Solar	0	0.002	0.052	0.552
- Coal, Specific Uses	0.658	1.432	4.340	11.988
- Feedstocks**	1.792	3.923	6.442	9.596
Total Commercial	22.625	46.657	117.980	293.636
Non-commercial	20.309	27.322	34.238	40.181
Constrained Scenario				
- Substitutable fossil fuels*	10.008	19.027	30.742	47.487
- Motor fuels	7.196	10.305	14.415	20.589
- Electricity	2.971	6.492	12.721	22.121
- Soft Solar	0	0.001	0.027	0.171
- Coal, Specific Uses	0.658	1.212	2.030	3.152
- Feedstocks**	1.792	3.723	5.098	6.164
Total Commercial	22.625	40.761	65.033	99.684
Non-commercial	20.309	27.171	33.264	37.788
Energy Efficiency Scenario				
- Substitutable fossil fuels*	10.008	17.125	31.529	60.763
- Motor fuels	7.196	9.872	14.379	22.459
- Electricity	2.971	6.621	14.724	30.050
- Soft Solar	0	0.006	0.067	0.403
- Coal, Specific Uses	0.658	1.224	2.363	4.381
- Feedstocks**	1.792	3.771	5.393	7.097
Total Commercial	22.625	38.619	68.455	125.152
Non-commercial	20.309	27.203	33.358	37.996

* Includes kerosene used for lighting.
** Includes non-energy oil

Table 4.31. Summary of Energy Demand Projections by Energy Forms

Scenario/Energy Forms	Growth rate 1993–2023 [% per year]	Amount [MTOE]		Share [%]	
		1992–93	2022–23	1992–93	2022–23
Reference Scenario					
Total Commercial	6.93	22.625	168.887	100	100
of which:					
Fossil fuels*	7.33	12.458	103.976	55.06	61.57
Motor fuels	4.70	7.196	28.524	31.81	16.89
Specific electricity	8.68	2.971	36.075	13.13	21.36
Soft Solar	-	0	0.312	0	0.18
Total Non-commercial	2.11	20.309	37.996	100	100
of which:					
Bagasse	4.30	2.078	7.350	10.23	19.34
Wood, Dung, Crop residues & Charcoal	1.75	18.231	30.646	89.77	80.66
Optimistic Scenario					
Total Commercial	8.92	22.625	293.636	100	100
of which:					
Fossil fuels*	9.48	12.458	188.599	55.06	64.23
Motor fuels	6.15	7.196	43.083	31.81	14.67
Specific electricity	10.62	2.971	61.402	13.13	20.91
Soft Solar	-	0	0.552	0	0.19
Total Non-commercial	2.30	20.309	40.181	100	100
of which:					
Bagasse	5.21	2.078	9.534	10.23	23.73
Wood, Dung, Crop residues & Charcoal	1.75	18.231	30.646	89.77	76.27
Constrained Scenario					
Total Commercial	5.07	22.625	99.684	100	100
of which:					
Fossil fuels*	5.19	12.458	56.803	55.06	56.98
Motor fuels	3.57	7.196	20.589	31.81	20.65
Specific electricity	6.92	2.971	22.121	13.13	22.19
Soft Solar	-	0	0.171	0	0.17
Total Non-commercial	2.09	20.309	37.788	100	100
of which:					
Bagasse	4.20	2.078	7.142	10.23	18.90
Wood, Dung, Crop residues & Charcoal	1.75	18.231	30.646	89.77	81.10
Energy Efficiency Scenario					
Total Commercial	5.87	22.625	125.152	100	100
of which:					
Fossil fuels*	6.03	12.458	72.241	55.06	57.72
Motor fuels	3.87	7.196	22.459	31.81	17.95
Specific electricity	8.02	2.971	30.050	13.13	24.01
Soft Solar	-	0	0.403	0	0.32
Total Non-commercial	2.11	20.309	37.996	100	100
of which:					
Bagasse	4.30	2.078	7.350	10.23	19.34
Wood, Dung, Crop residues & Charcoal	1.75	18.231	30.646	89.77	80.66

* Includes coke, fertilizer feedstocks, non-energy oil and kerosene used for lighting but excludes motor fuels.

In the base year the per capita electricity consumption was 302 kW·h. The projected per capita electricity consumption, in the year 2022–23, in various scenarios are: Optimistic Scenario 3214 kW·h; Reference Scenario 1888 kW·h; Energy Efficiency Scenario 1573 kW·h; and Constrained Scenario 1158 kW·h. Figure 4.10 gives a comparison of the present and projected per capita electricity consumption of Pakistan with some selected countries. It may be noted that according to the projections of the study, 30 years from now, the level of per capita electricity consumption in Pakistan will be similar to the present day consumption levels of Argentina, Malaysia and Turkey in the Reference, Energy Efficiency and Constrained Scenarios. However, in the case of the Optimistic Scenario, the level will be similar to the present day consumption levels of the Republic of Korea.

As shown in Table 4.32 the income elasticity of electricity demand which was very high during the last two decades (1.6 to 1.8) declines gradually to a level of 1.06 to 1.19 in all the scenarios by the end of the study period.

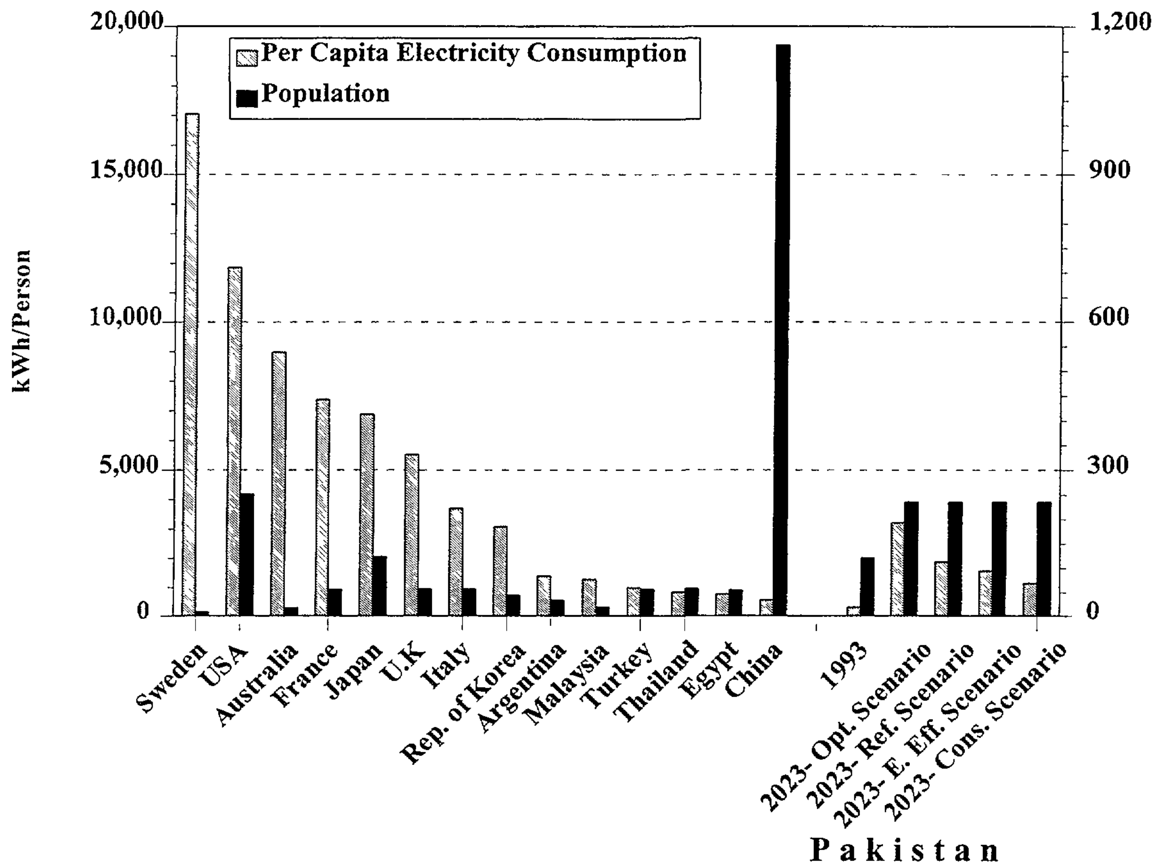


FIG.. 4.10. Population and Per Capita Electricity Consumption in Selected Developed and Developing Countries

Note: Data for countries other than Pakistan corresponds to the period 1990–1992

Table 4.32. Historical and Projected Income Elasticities of Electricity Demand

	1973–1983	1983–1993	1993–2003	2003–2013	2013–2023
Electricity Demand Growth Rates [% p.a.]					
Reference Scenario	8.95	9.94	8.85	9.08	8.11
Optimistic Scenario	8.95	9.94	9.57	11.59	10.71
Constrained Scenario	8.95	9.94	8.13	6.96	5.69
Energy Efficiency Scenario	8.95	9.94	8.34	8.32	7.39
GDP Growth Rates [% p.a.]					
Reference Scenario	5.73	5.54	6.98	7.00	7.00
Optimistic Scenario	5.73	5.54	7.49	8.99	9.01
Constrained Scenario	5.73	5.54	6.49	5.42	5.13
Energy Efficiency Scenario	5.73	5.54	6.98	7.00	7.00
Income Elasticity					
Reference Scenario	1.56	1.79	1.27	1.30	1.16
Optimistic Scenario	1.56	1.79	1.28	1.29	1.19
Constrained Scenario	1.56	1.79	1.25	1.28	1.11
Energy Efficiency Scenario	1.56	1.79	1.19	1.19	1.06

4.4.4. Analysis of Sectoral Electricity Demand Projections

The electricity requirements projected for the four scenarios are given in Table 4.33. It may be noted that the major electricity consuming sectors in the base year are Manufacturing and Households with shares of 35.4% and 36.1%, respectively. In the Reference scenario the share of Manufacturing sector increases to 64.5% while the share of Households declines to 25.4% by the year 2022–23. The main reason for this is that the Reference scenario assumes 9–10% p.a. growth in the value added of the Manufacturing sector and the share of Manufacturing sector in total GDP increases from 17.3% in the base year to 31.5% by the year 2022–23. Further, the intensity of electricity use in this sector is the highest and penetration of electricity for various end-uses in this sector have also been assumed in the Reference scenario. Growth rate of electricity consumption in the Manufacturing sector during the 1993-2023 period is 10.9% p.a. while the growth rate of value added of Manufacturing in the corresponding period is 9.2% p.a. giving and income elasticity of 1.19.

Table 4.33. Electricity Demand Projections by Sector

Scenario/Sector	1992–93	2002–03	2012–13	2022–23
Reference Scenario [MTOE]	2.971	6.939	16.548	36.075
1. Agriculture	15.44%	7.89%	3.79%	1.87%
2. Construction	0.01%	0.04%	0.08%	0.16
3. Mining	0.05%	0.06%	0.06%	0.07%
4. Manufacturing	35.35%	46.17%	55.15%	64.45%
5. Transportation	0.39%	0.47%	0.48%	0.59%
6. Household	36.10%	34.84%	31.97%	25.40%
7. Service	12.65%	10.53%	8.47%	7.46%
Optimistic Scenario [MTOE]	2.971	7.413	22.202	61.402
1. Agriculture	15.44%	7.67%	3.33%	1.43%
2. Construction	0.01%	0.04%	0.07%	0.11%
3. Mining	0.05%	0.06%	0.05%	0.05%
4. Manufacturing	35.35%	46.70%	60.79%	70.95%
5. Transportation	0.39%	0.46%	0.46%	0.55%
6. Household	36.10%	34.64%	27.85%	20.92%
7. Service	12.65%	10.45%	7.46%	5.99%
Constrained Scenario [MTOE]	2.971	6.492	12.721	22.121
1. Agriculture	15.44%	8.36%	4.83%	2.97%
2. Construction	0.01%	0.04%	0.09%	0.18%
3. Mining	0.05%	0.06%	0.07%	0.09%
4. Manufacturing	35.35%	44.90%	50.87%	55.24%
5. Transportation	0.39%	0.49%	0.53%	0.66%
6. Household	36.10%	35.51%	34.34%	31.84%
7. Service	12.65%	10.64%	9.27%	9.02%
Energy Efficiency Scenario [MTOE]	2.971	6.621	14.724	30.050
1. Agriculture	15.44%	7.79%	3.65%	1.83%
2. Construction	0.01%	0.04%	0.09%	0.18%
3. Mining	0.05%	0.07%	0.07%	0.07%
4. Manufacturing	35.35%	46.01%	55.00%	64.48%
5. Transportation	0.39%	0.56%	0.80%	1.11%
6. Household	36.10%	35.32%	32.61%	26.18%
7. Service	12.65%	10.23%	7.78%	6.15%

Since the Constrained Scenario represents the least industrialization case, with the Manufacturing sector having a share of 25% in the total GDP in the year 2022–23, the share of the Manufacturing sector in the total electricity consumption in this scenario is also the lowest (55%) among all the scenarios. In all the scenarios the share of the Agriculture sector declines rapidly from 15.4% in the base year to 1.4–2.9% in the year 2022–23. Service sector, inspite of the decline in its share, becomes the third most important electricity consuming sector in all the scenarios. Construction, Mining and Transport sectors remain very minor electricity consuming sectors in all the scenarios.

The electricity demand projections presented in Table 4.33 correspond to the national grid and do not include the self and co-generated electricity produced by the industries. As stated in Section 4.3 of Appendix A the estimated self and co-generated electricity consumption in the Manufacturing sector was about 15% of the grid supplied electricity, in this sector, in the base year 1992–93. It is projected that the level of self and co-generated electricity will be about 4–12 times the base year value, in the year 2022–23, in different scenarios. However, the share of self and co-generated electricity will decline from 15% in the base year to about 4–6% of the national grid electricity demand of Manufacturing sector by the year 2022–23 (see Table 4.34).

4.5. Comparison of Projections of Final Energy Demand with Other Studies

Long term projections of final energy and electricity demand prepared by the Energy Wing of the Planning Commission are available from the background study done for the preparation of the Eighth Five Year Plan (1993–1998) and the Perspective Plan (1993–2008). According to this study the growth rate of demand for commercial final energy has been projected as 7.0% p.a. for the period 1991–2018. These projections correspond to 6.5% p.a. GDP growth assumption for this period resulting in an income elasticity of 1.08. The growth rate of final energy demand in the present MAED study has been estimated as 7.0% p.a. during the period 1993–2018 while the underlying assumption for GDP growth rate is 7.0% p.a. The resulting income elasticity in this study has been estimated as 1.0 for the same period (see Table 4.35).

Table 4.34. Self and Co-generation of Electricity in Manufacturing Sector

	1992–93	2002–03	2012–13	2022–23
Self and co-generation in Manufacturing sector (GW·h)				
Reference scenario	1936	3489	6561	12741
Optimistic scenario	1936	3747	9423	22766
Constrained scenario	1936	3194	4730	6880
Energy efficiency scenario	1936	3588	6929	13453
Self and co-generated electricity as % of Manufacturing sector electricity demand of the grid				
Reference scenario	15.0	8.9	5.9	4.5
Optimistic scenario	15.0	8.8	5.7	4.3
Constrained scenario	15.0	8.9	5.9	4.6
Energy efficiency scenario	15.0	9.6	7.0	5.7

Table 4.35. Comparison of Projections of Commercial Final Energy and Electricity Demand by the MAED Study with those by the Energy Wing

	2017–18	
	Energy Wing*	MAED (Reference Scenario)
1. GDP Growth rate	6.5% p.a. (1991–2018)	7.0% p.a. (1993–2018)
2. Final Commercial Energy (excluding non-energy uses)	115.5 MTOE	109.0 MTOE
3. Final Commercial Energy Demand Growth rate	7.02% p.a. (1991–2018)	6.98% p.a. (1993–2018)
4. Final Commercial Energy Elasticity	1.08	1.00
5. Final Electricity Demand	22.0 MTOE (270.5 TW·h)	24.4 MTOE (299.6 TW·h)
6. Final Electricity Demand Growth rate	8.16% p.a. (1991–2018)	8.79% p.a. (1993–2018)
7. Final Electricity Elasticity	1.26	1.26

* Source: [29]

As for electricity demand the same study by the Energy Wing has projected the demand for electricity to grow at 8.2% p.a. during the period 1991–2018 with income elasticity of 1.26. The corresponding growth rate in the present study is projected as 8.8% p.a. with resulting income elasticity of 1.26. Although the level of details and some of the assumptions in the two studies are different, the projections of final energy and electricity in both studies are very close.

4.6. Conclusions

The MAED analysis has shown that in the Reference, Optimistic and Constrained scenarios the commercial final energy demand will grow at approximately the same rate as that of the economy while the electricity demand will grow at rates higher than the economic growth rates. In the Reference scenario, the commercial final energy demand will grow at 7.0% p.a. while the electricity demand will grow at 8.7% p.a., some 25% higher growth rate than that of the economy during the next 30 years. In the case of Optimistic scenario, envisaging 8.5% p.a. average growth, the commercial final energy and electricity demands will be some 75% and 70% higher, respectively, by the year 2022–23, compared to the Reference scenario. In the case of Constrained scenario, envisaging 5.7% p.a. average growth rate, the commercial final energy and electricity demands will be some 42% and 39% lower, respectively, by the year 2022–23, compared to the Reference scenario. The analysis of the Energy Efficiency Scenario shows that by pursuing vigorous energy efficiency and conservation policies involving enhancement of awareness, enforcement of regulations and adoption of fiscal and pricing measures, the 7.0% p.a. economic growth envisaged in the Reference Scenario can be achieved by some 27% lower final energy (including electricity) and some 17% lower electricity consumption by the year 2022–23.

Chapter 5

ELECTRICITY LOAD PROJECTIONS

5.1. Introduction

Availability of realistic estimates of future temporal growth in peak power demand and of the associated changes in the shapes of load duration curves is essential for any meaningful medium to long term electric system expansion planning study This aspect has been rather weak in the various studies undertaken so far in Pakistan In some of the earlier studies, projections for total electricity demand and peak power demand were made simply by applying judgmental growth rates to the base year values, or by correlating these demands with a couple of economic variables In these studies the sectoral demands were not worked out separately nor any estimates were made for possible future changes in the shapes of load curves [68, 69] In some recent studies [70, 71], although the end-use demand of electricity was projected sector-wise, the peak demand estimates were still arrived at by applying a constant load factor to the total kW·h electricity demand, after adjusting it for transmission and distribution losses Further, no effort was made to estimate the changes in future load duration curves resulting from different evolutions of various sectoral demands Instead, the load duration curves available for a recent year were assumed to be applicable to the future years as well

The electricity demand projected with the help of Module 1 of the MAED model (see Chapter 4) is in the form of annual electricity requirements at the user end This demand has to be converted to hourly demand at the generation system level so that the requirements of electricity generation system expansion could be planned The distribution of electrical load over time, which characterizes the pattern of electricity usage, is crucial for selection of generating units to be added and for their loading in the system The WASP model used for the generation system expansion (see Chapter 7) requires as input the projections of system peak demand and load duration curves This information has been prepared in the present study with the help of Modules 2 and 3 of the MAED model

5.2. Methodological Approach

Module 1 of MAED calculates the sectoral electricity demand at the user level In the present study, the electricity consumed by pipelines used for the transportation of oil from the sea-port to the up country have been calculated outside the model and this additional electricity consumption has been given as input to Module 1, which is then added to the electricity demand calculated by the model The electricity losses occurred in transmission and distribution are then added to this demand through the ELOSS parameter in Module 1 The resulting electricity demand is considered as the electricity generation requirements in a particular year of the study.

Module 2 uses the annual electricity generation requirements in different sectors of the economy and converts them into hourly system load by taking into account the seasonal variation of electricity consumption in different sectors, changing level of consumption depending on the day type (working day, week-end, etc), and the hourly load pattern of demand

Table 5.1. Evolution of Sectoral Electricity Consumption

	1961-62	1966-67	1971-72	1976-77	1981-82	1986-87	1992-93
Electricity Consumption (Million kW·h)	1265	2759	5333	7068	12 698	21 697	36 493
Shares (%) by sector							
Agriculture	14 1	14 1	18 7	19 8	18 6	16 0	15 4
Industry	53 9	55 9	53 5	43 7	39 4	36 9	35 7
Transport	0 0	0 0	0 8	0 6	0 3	0 2	0 1
Household	18 6	13 8	11 9	18 4	25 4	31 4	36 1
Service	5 3	6 3	7 7	9 9	9 1	8 6	6 4
Miscellaneous	8 1	9 9	7 4	7 6	7 2	6 9	6 3

Average Annual Growth Rates						
Agriculture	17 0%	20 7%	7 0%	11 1%	7 9%	8 4%
Industry	17 8%	13 0%	1 6%	10 1%	9 9%	8 5%
Transport	0 0%	0 0%	0 2%	-0 5%	-2 0%	-5 5%
Household	10 3%	10 7%	15 3%	20 0%	16 1%	11 6%
Service	21 3%	18 4%	11 3%	10 5%	10 0%	5 3%
Miscellaneous	21 5%	7 6%	6 5%	11 0%	10 7%	5 5%

Source [14 &16]

in these sectors Module 3 rearranges the hourly system load in decreasing order to work out the system peak demand and load duration curves

5.3. Features of Electricity Load in Pakistan

5.3.1. Historical Electricity Consumption Pattern

Electricity consumption in Pakistan grew by a factor of about 29 over the last 30 years resulting in an average growth rate of 12% per annum, which is twice as high as the corresponding GDP growth rate At the same time, the sectoral pattern of electricity consumption underwent considerable change due to widely different growth rates experienced in the various economic sectors Table 5 1 gives the shares of different sectors in total electricity consumption and the corresponding growth rates from 1962 to 1993 It is seen that over the last 30 years the shares of the Industry and Household sectors have undergone most profound changes, the former decreasing from about 54% in 1962 to 36% in 1993 and the latter increasing from 19% to 36% over the same period. These changes have not been uniform throughout the whole 30 years The share of the Industry sector was essentially constant until 1972, it dropped rapidly during 1972-1977 and has since been decreasing gradually The share of the Household sector actually decreased during 1962-1972 but has since been increasing rather rapidly The share of the

Agriculture sector has followed a somewhat opposite trend, it first increased till 1976-77 and then decreased slightly in 1981-82 and finally decreased significantly during 1987-1993

The large variations in sectoral growth rates experienced during the last 30 years have been mainly the result of changes experienced in different periods in the growth rates of various demand determining factors such as sectoral economic activity levels, structural shift in the composition of industrial activity, urbanisation, pumped irrigation, shift of pumped irrigation from diesel to electric pumps, use of air conditioners and other electric appliances by Household and Commercial establishments etc The evolution of these various factors will determine the growth of future electricity demand and changes in its sectoral distribution pattern

5.3.2. Composition of the Electrical Load Curve at National Level

Figures 5 1 and 5 2 show the national load curves for typical working days of March and July 1983 respectively, split into components corresponding to different sectoral and sub sectoral demands It may be noted that the shapes of the daily load curves are markedly different for the various demand components Further, the effect of change of season is very pronounced for certain demand components (e g cooling and air-conditioning) and hardly any for others (e g industrial demand) Cooling and air-conditioning load in summer creates a hump in system load curve during the day time whereas there is a dip in the load curve during winter due to absence of cooling and air-conditioning load The evening peak in both curves in Figs 5 1 and 5 2 is due mainly to the lighting requirements of the Residential sector The time of occurrence of this peak also undergoes seasonal variation the peak occurs one hour too early in March than in July The peak demand reaches its maximum, generally, in the last week of June or the first week of July

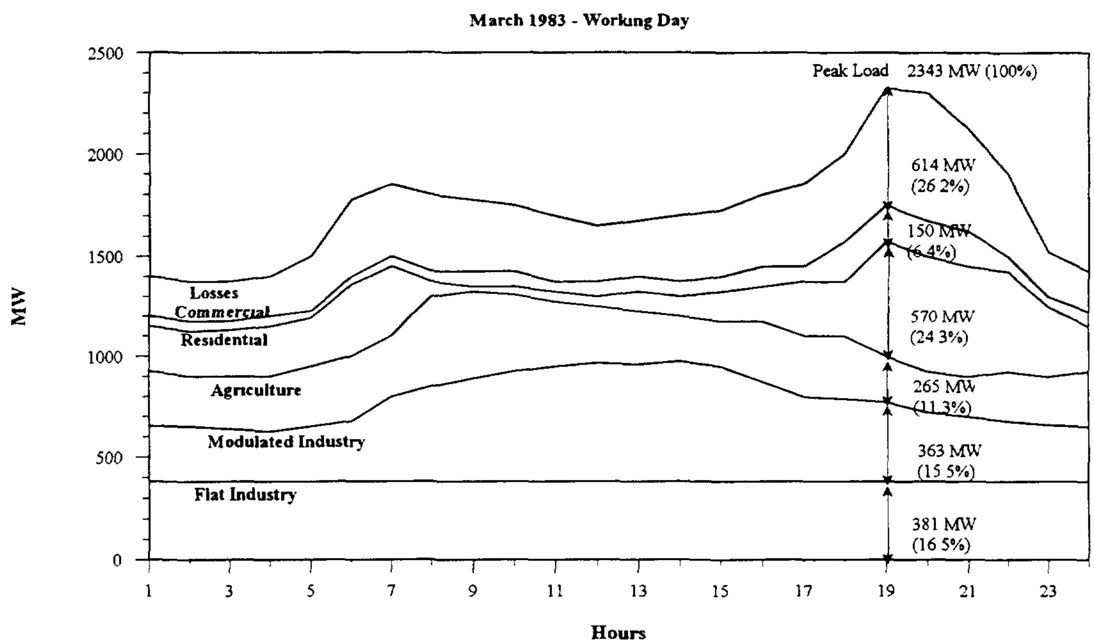


FIG 5 1 Sectoral Composition of The National Load Curve

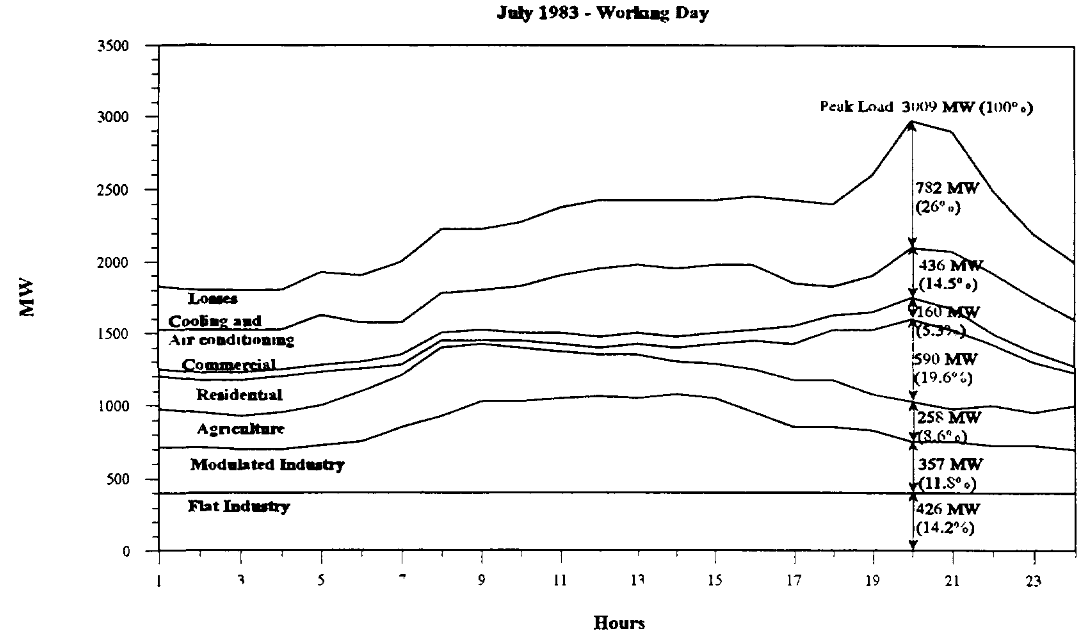


FIG 5 2 Sectoral Composition of The National Load Curve

As the overall load curve is the sum of a number of sectoral load curves, which all have very different shapes and seasonal variations, its shape is expected to undergo significant changes from year to year as the relative shares of various sectors in electricity demand change with time. How significant such changes have been in the past may be judged from Fig 5.3, which shows the variation of annual load factor (defined as the ratio of average load to peak load) from 1961 to 1989. Here, superimposed on short term fluctuations, one can clearly see an increasing trend in the annual load factor during the 1960s and a gradual decline thereafter. The declining trend in annual load factor since 1970 is due to increase in the share of electricity consumption by the Household sector and a simultaneous decrease in the share of electricity consumption in industry. It may be noted that the value of the annual load factor decreased from about 70% in the late 1960s to around 60% in 1989. The share of the Household sector in total electricity consumption during this period increased by 20 percentage points while the share of industry decreased by about 17 percentage points during the same period

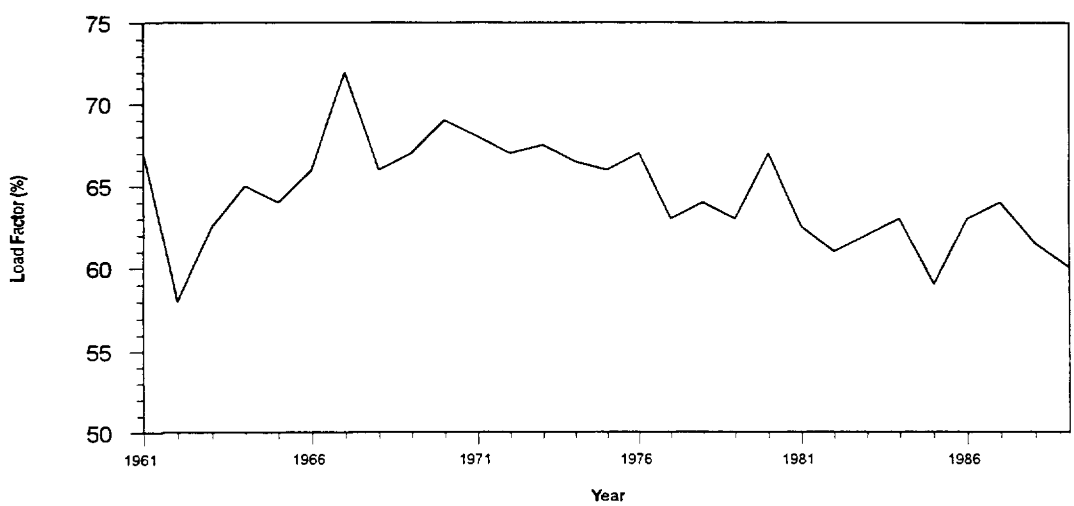


FIG 5.3 Variation in Annual Load Factor

In view of this, it would be unrealistic to assume the constancy of annual load factor and shapes of load duration curves over the next two to three decades as has been done in the previous electric system expansion planning studies in Pakistan [68, 69, 70, 71, 72, 73]

Since the pattern of sectoral electricity consumption is expected to change considerably over the next 30 years (as discussed in the previous section), the annual load factor and the shapes of overall load curves will also undergo large variation during this period It is, therefore, necessary to estimate the time distribution of power load in different sectors to arrive at realistic projections of load duration curves and peak demand for the overall system

5.4. Reconstruction of Load Profiles For The Base Year

5.4.1. End Use Categories

For reconstruction of electricity load profiles of the base year, Module 2 of MAED divides the total electricity consumption into two major categories, viz (i) Industry/ Agriculture/ Transport, and (ii) Residential/ Commercial, and provides option for defining five types of clients in each category

In the first category, four types of clients are considered in the present study, namely (a) large scale industries, (b) small scale industries, (c) agriculture, and (d) transport However, in the case of 2nd category, the clients option has been used in a somewhat different way, i e by type of activity of end-use of electricity in the Residential and Commercial sectors, viz (a) lighting, (b) air-cooling, (c) air-conditioning, (d) other appliances, and (e) all uses in the Commercial sector The later description facilitates the analysis of electricity load variations resulting from policies targeting load management and end-use efficiency improvements

As mentioned in Chapter 2, there are two power utilities in Pakistan responsible for power generation, transmission and distribution The networks of these utilities are interconnected by 220 kV lines The power peak load and energy consumption information of their respective systems is reported on monthly basis But details of sectoral consumption is only reported on a yearly basis For the application of MAED Modules 2 and 3, information on seasonal electricity consumption by each client in various sectors and the typical load curve of each client for different seasons are required The month-wise electricity consumption by different sectors of the economy was obtained from power utilities, while typical load curves of various clients in these sectors for different seasons were derived from estimated load curves based on [58, 73, 21, 74, 75, 76, and 77] In order to incorporate the effect of load shedding to adjust seasonal load variation the total electricity generation shed in the base year has been distributed over different sectors on the basis of their shares in total consumption This assumption does not truly reflect the actual situation, but is a compromise in the absence of detailed information

5.4.2. Load Modulation Coefficients

In the MAED methodology, the load curves for various clients in different end-use sectors are constructed using electricity consumption by each client and load modulation coefficients The load modulation coefficients for various sectors include the following (a) seasonal coefficients, representing the seasonal variation in electricity consumption, (b) daily coefficients, accounting for the relative weights of working and non-working days and (c) hourly coefficients, describing the hourly load variation behavior of the sector The sectoral/ client load curves are then summed together to obtain the overall system load curves

In order to estimate the various load modulation coefficients one needs to have the hourly demand data for various sectors. Such an information is not collected/maintained by the utilities in Pakistan; only monthly energy consumption by various consumers is recorded for billing purposes. A survey was conducted [73] to collect sample data about seasonal, weekly and daily variations in power demand of different types of consumers in connection with a load management study. This survey covered 5-10% of each type of consumers, widely distributed over different geographical regions. Based on information collected from utilities and the above referred to survey, the load modulation coefficients for various clients in the two sectors have been derived and are discussed below.

In Module 2 of the MAED model, provision has been made for five type of days in normal weeks of a year while another 5 types of days can be defined for special weeks of the year, e.g. vacations or special holidays. In the present study, two types of week days have been considered, i.e. the working days (Saturday through Thursday) and non-working day (Friday). However, due to change in the official holidays in a week from the year 1994 and onwards, Sunday through Thursday have been considered as working days while Fridays and Saturdays have been assumed to be non-working days. For all working days within a season, it has been assumed that the hourly load variations will remain the same. Similarly the same load variations have been assumed for both of the non-working days. However, different weights have been assigned for the working and non-working day electricity load of various sectors. It has been assumed that in the Industrial sector the weight of a non-working day relative to a working day will be 0.775. The weight of a non-working day has been assumed to vary from 0.97 to 1.01 during the year as compared to unity for a working day for the Household and Service sector.

The following paragraphs discuss the time variation of electric load behavior in different sectors of the economy.

Figure 5.4 shows the seasonal variation in electricity consumption (adjusted for growth within a year) for the two major sectors considered in the present study viz. Industry which includes the Agriculture and Transport sectors, and the Household and Service sector. There is not much seasonal variation in the Industrial sector while the electricity consumption in the Household and Service sector undergoes large variation due to the extreme summer and winter periods in most of the areas of Pakistan.

The further break-up of the individual sectors of Industry and the Agriculture is shown in Fig. 5.5 which again illustrates that electricity requirements in both of these sectors have very little variation. The seasonal variation in the electric load for the Household and Service sectors is shown in Fig. 5.6. It is obvious that the electricity consumption in the summer period (May to October) is higher as compared to the winter period (November to April) due to higher cooling load in these sectors comprising of fans, air-coolers and air-conditioners.

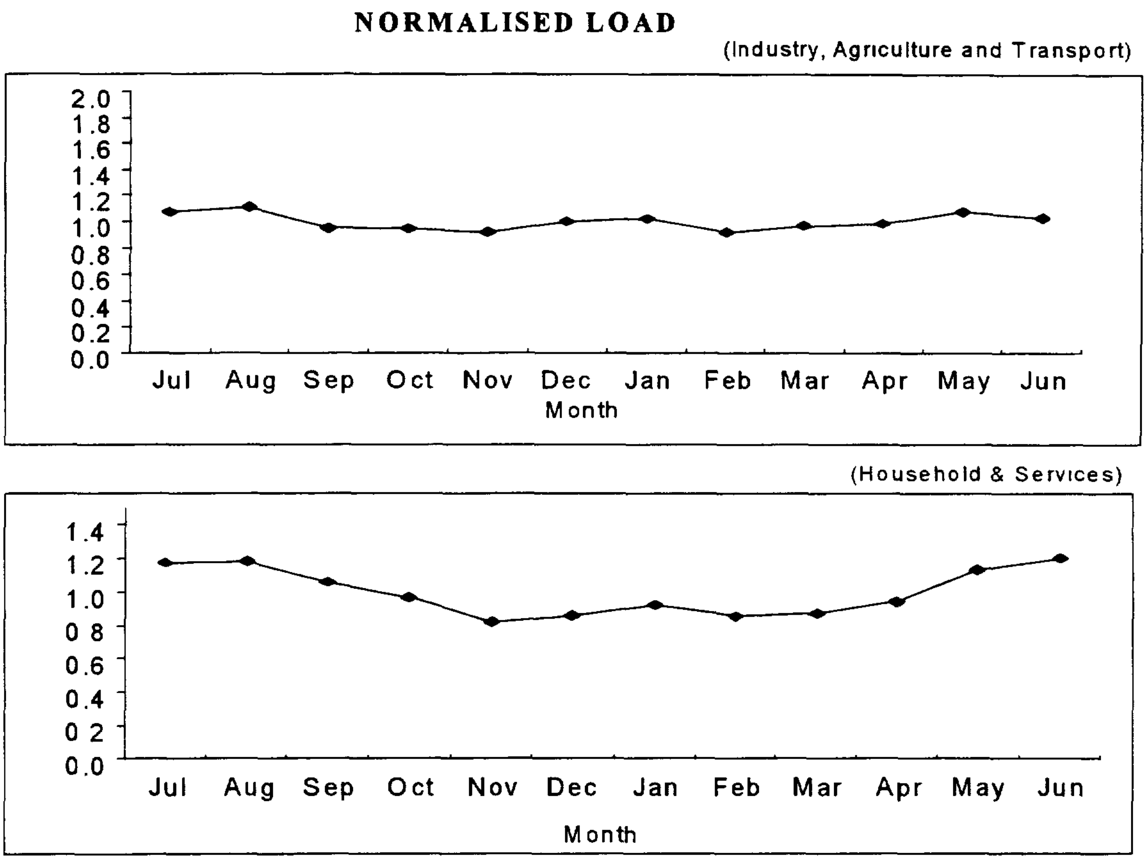


Figure 5 4 Seasonal Variation in Electricity Consumption

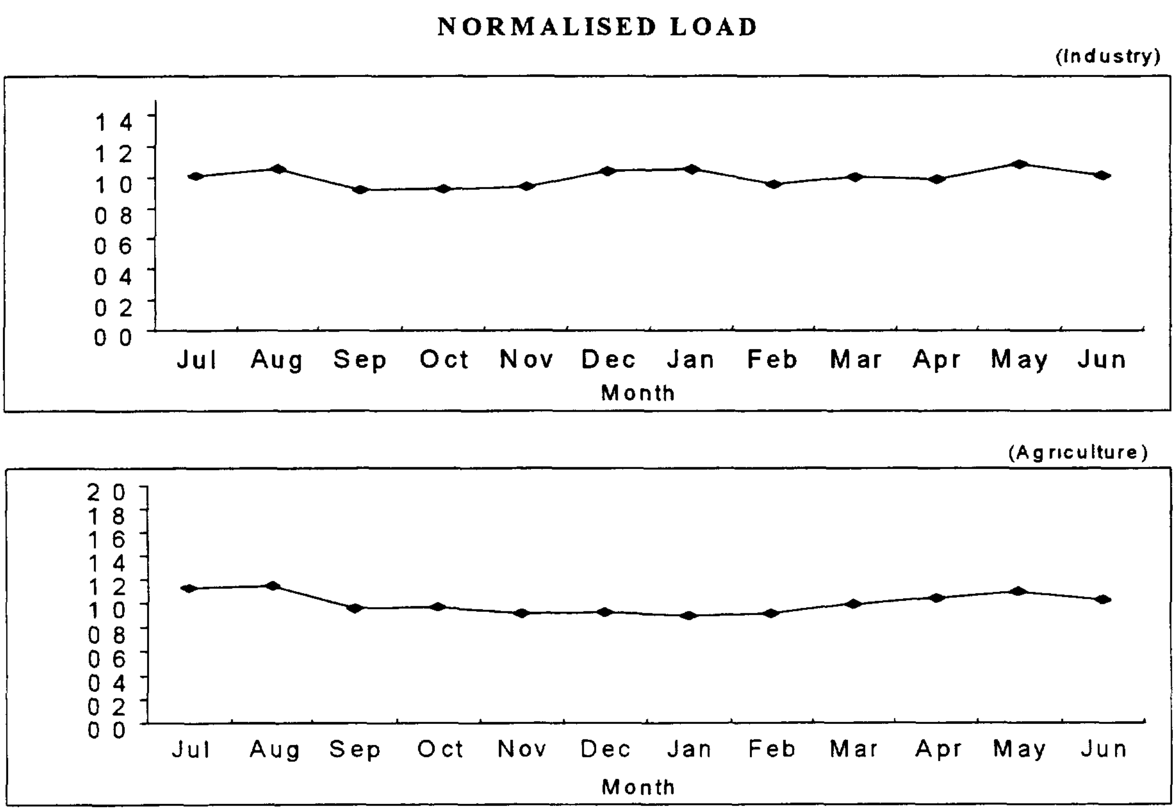


Figure 5 5. Seasonal Variation in Electricity Consumption

NORMALISED LOAD

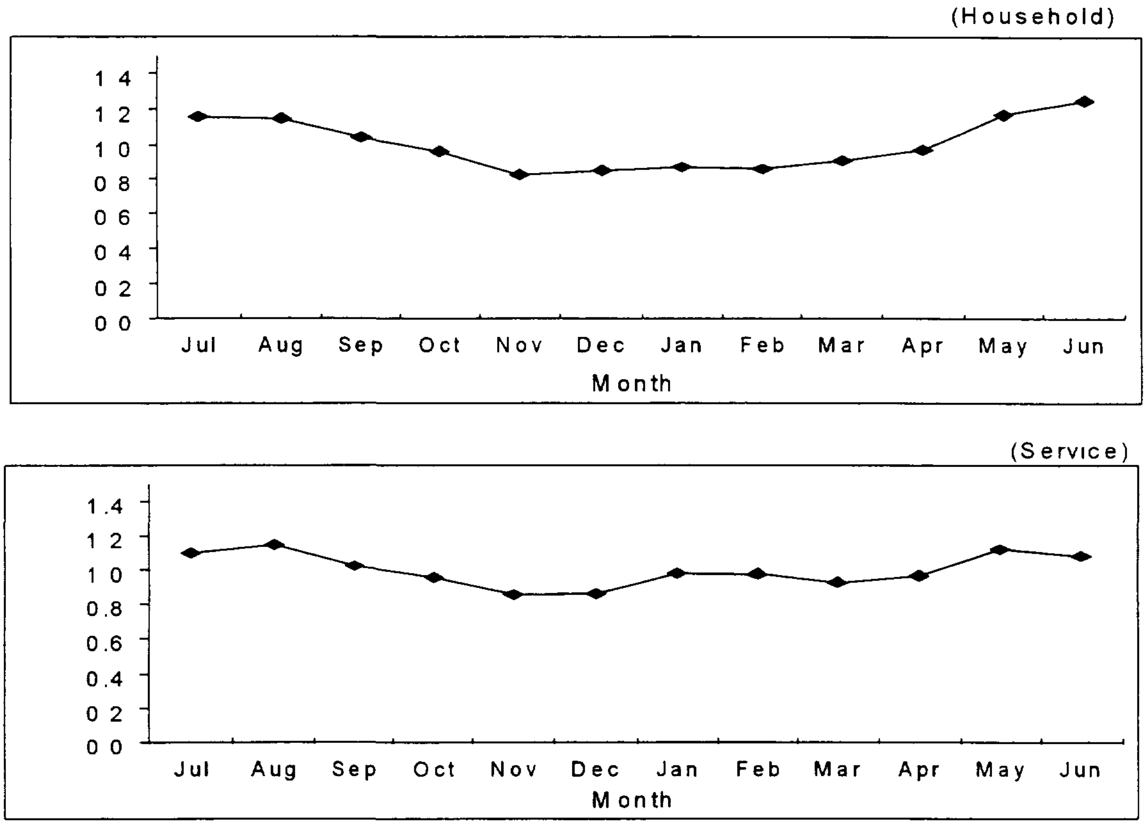


Figure 5.6 Seasonal Variation in Electricity Consumption

Figures 5.7 through 5.12 show the daily load variation in the different sub-sectors used in the present study. The load in the large scale industries increases gradually during day time and a peak is observed at almost mid of the day. In small scale industries various peaks are observed at the day time due to non-standard timings of these industries. In the Commercial sector, a significant peak load exists in the evening. The specific time of this peak varies in summer and winter days. The load is at the lowest level at mid-night and goes on increasing as the business timings start. The electric load in the Agriculture sector undergoes large variation around the clock, however a relatively smaller load is observed in the evening, which may be due to the forced load shedding during this period in which the system peak exists. Two significant peaks exist in the household load, one of the peaks (the lower peak) occurs in the morning when people wake up while the other and the most significant peak exists in the evening when most of the people are at their homes after returning from their workplaces. As shown in the load curves for the individual types of appliances in the Household sector, the evening peak consists of lighting and other appliances load. The cooling load also contribute to the enhancement of this peak in the summer period. The load modulation coefficients worked out for various clients in different sectors are given in Appendix D.

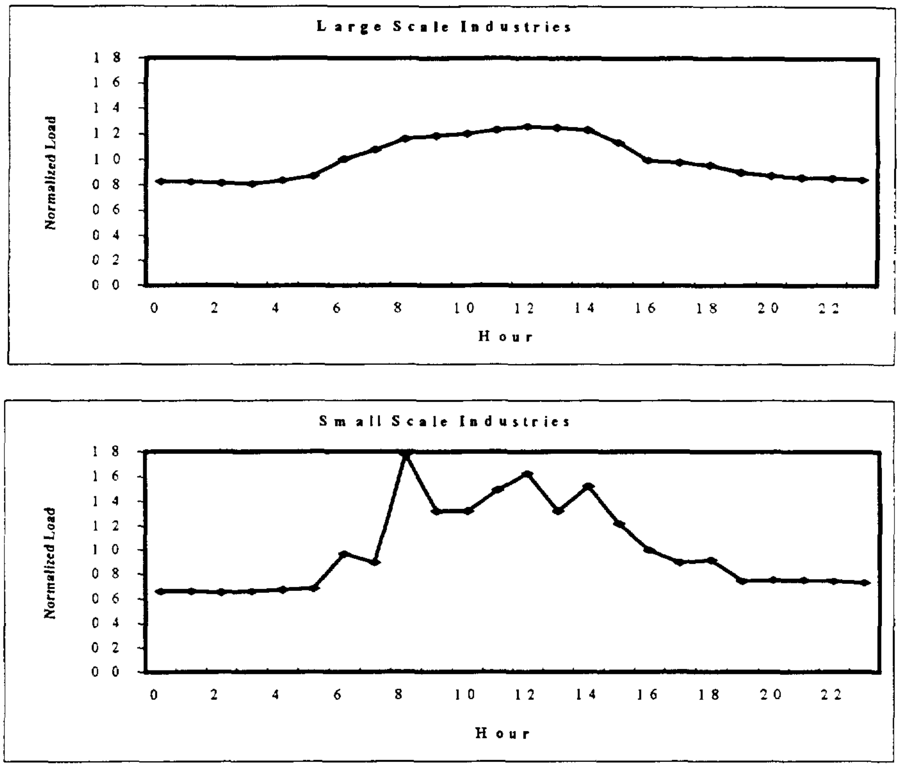


FIG. 5.7. Normalized Daily Load Curves (Industry)

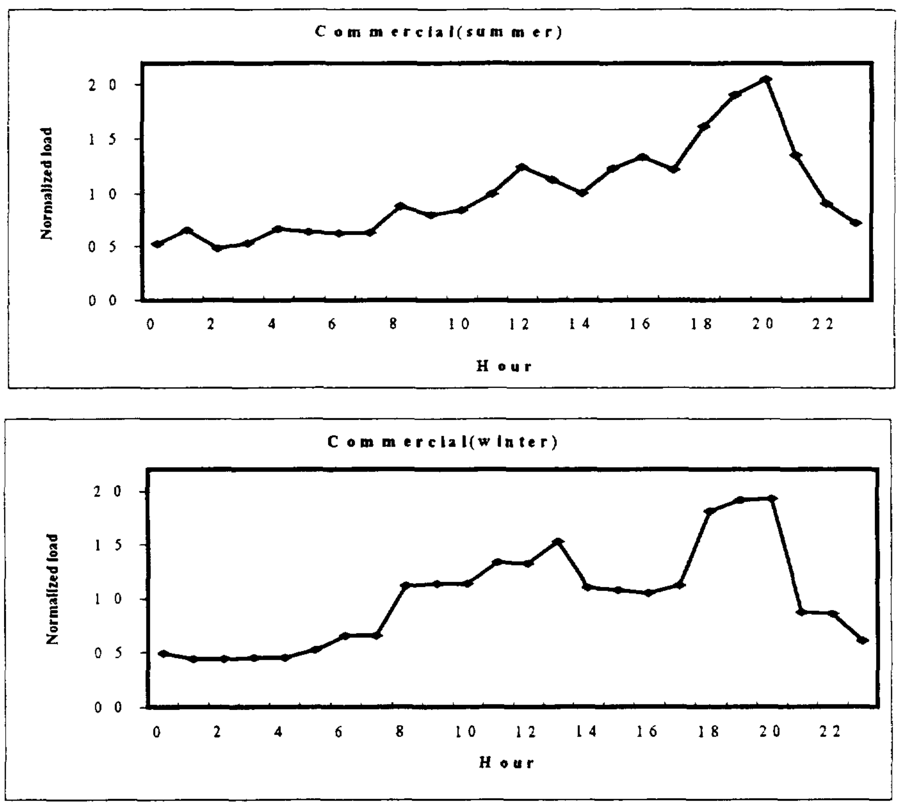


FIG. 5.8. Normalized Daily Load Curves (Commercial)

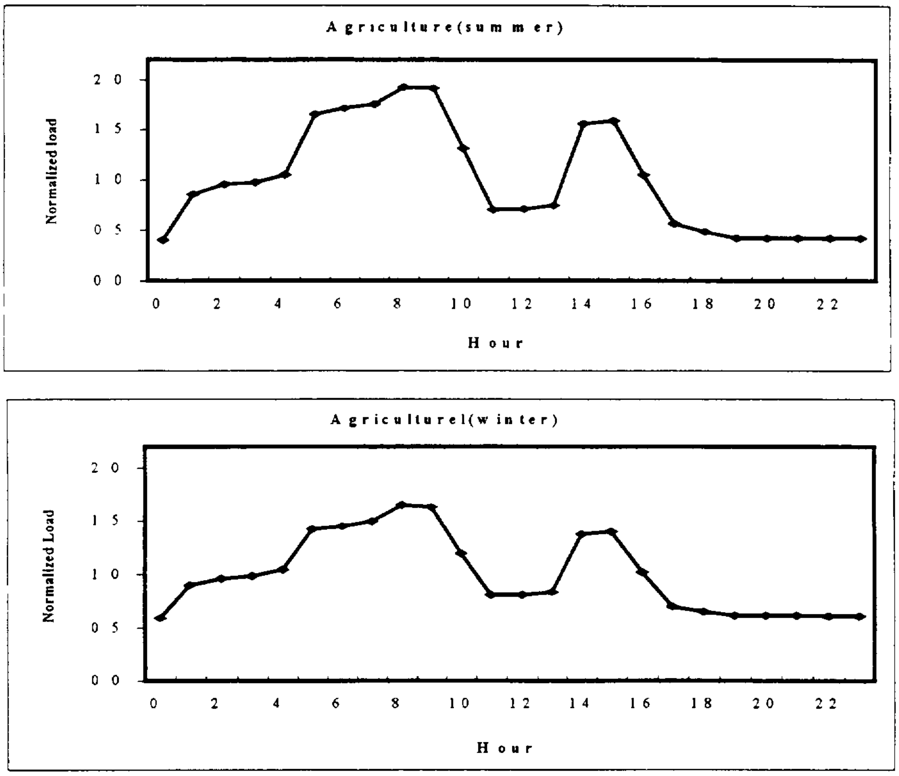


FIG. 5.9. Normalized Daily Load Curves (Agriculture)

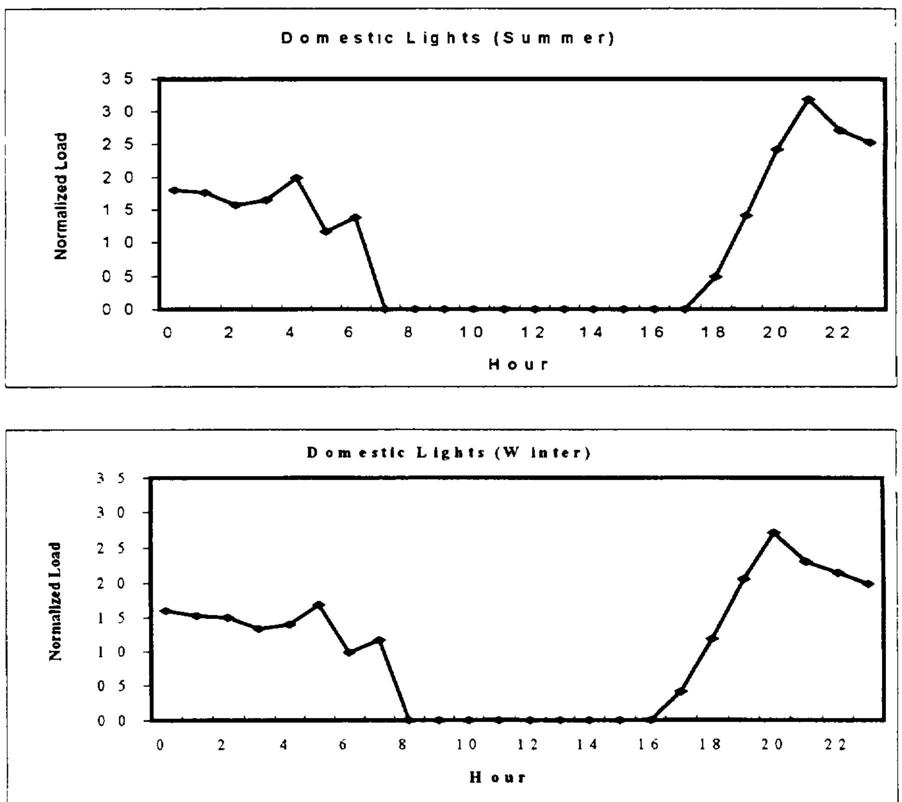


FIG. 5.10. Normalized Daily Load Curves (Domestic Lights)

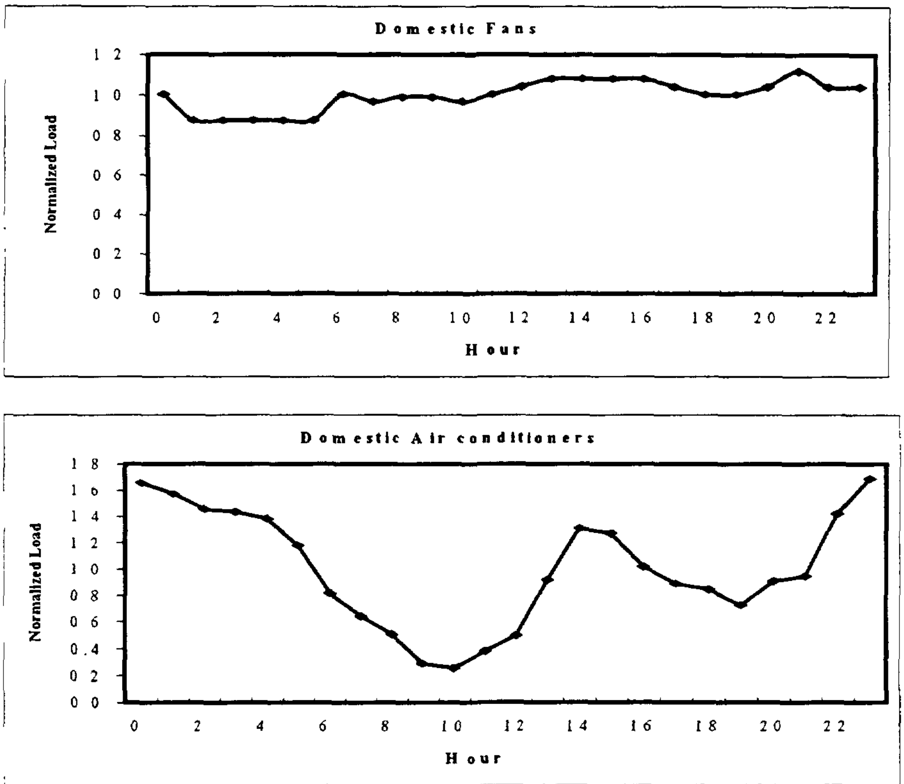


FIG. 5.11. Normalized Daily Load Curves (Domestic Fans & Air-conditioners)

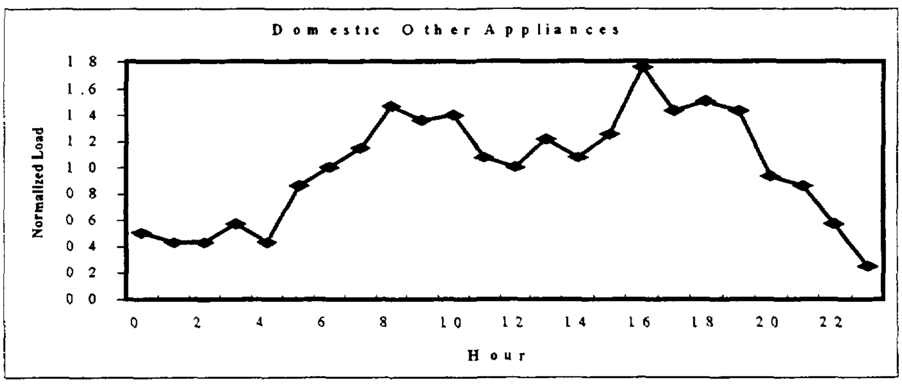


FIG. 5.12. Normalized Daily Load Curve (Domestic other Appliances)

5.4.3. Base Year Load Duration Curves

Using the adjusted electricity consumption by different end-use categories/clients and their corresponding load modulation coefficients, the system-wide hourly load for the base year has been worked out with the help of Module 2 of MAED. The hourly load has been converted to six bimonthly period Load Duration Curves (LDC) using Module-3 of MAED for direct input to the ELECTRIC module of ENPEP (where a year has been divided into six periods; see Chapter 7). The six normalized LDCs for the base year are shown in Fig. 5.13.

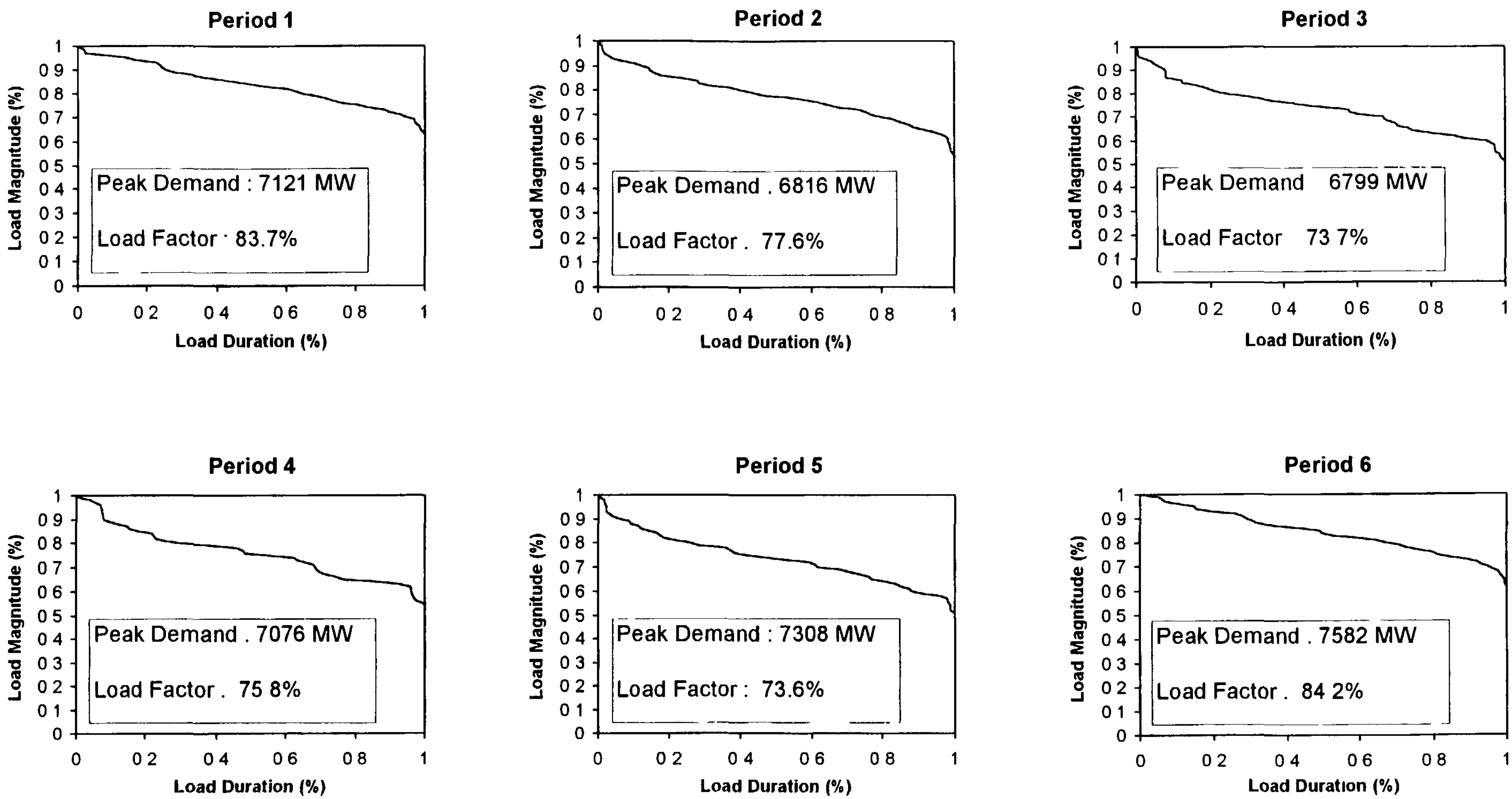


Figure 5.13: Load Duration Curves for 1992-93

5.5. Main Assumptions for Projecting Future Load Profiles

For projecting the future load profiles, it has been assumed that the daily load pattern of each client in various sectors of the economy will remain unchanged. This assumption is quite reasonable as, for example, the daily pattern of lighting activity in the household is determined by the lighting needs during the day and night; this pattern is expected to remain the same in future years as that in the base year. Similarly, the daily electricity load pattern of Agriculture is dictated by daily operation of irrigation water pumps and can be assumed to remain the same in future as in the base year. A similar assumption for the pattern of load profile of large and small scale industries has been made. Although, the change in the structure of large scale industry will have significant effect on the pattern of industrial load, detailed information is not available.

The seasonal variation of electricity consumption in different sectors of the economy has also been assumed to remain constant throughout. This assumption is justified by the fact that the seasonal variation is dictated by physical factors which do not change very much from one year to another. For example, the weather conditions determine seasonality in electricity consumption for air-conditioning and cooling. Similarly, in the Agriculture sector the seasonal variation of electricity consumption is determined by the pattern of irrigation requirements during the year. However, unpredictable weather changes like long dry summer will have a considerable impact on seasonal electricity consumption by various sectors. Such changes can not be accounted for in a long term study.

Apart from changes in the system losses, the principal factor which will influence the future pattern of system load are the changes in the contribution of various clients in the sectoral demand of electricity in different seasons. Since, the shares of various clients in the sectoral electricity demand are expected to change in future, the load profiles in future years will be different from that for the base year. For example, if the electricity consumption for lighting activity increases at a faster pace compared to all other activities, it will tend to increase the peak of system load compared to a situation in which industrial demand increases rapidly, which will tend to flatten the peak of system load. The expected changes in the shares of various clients in the sectoral electricity demand projected by Module 1 of MAED for the four demand scenarios are discussed in the next section.

As for the system losses, the utilities have planned to gradually reduce system losses from about 25% now to 19% by 1998, 17.5% by 2003 and further down to 16% by 2008. The same targets have been adopted in the Reference, Optimistic Growth and Constrained Growth scenarios of the present study. In the Energy Efficiency Scenario further reduction in system losses has been assumed. The system losses assumed for this scenario are 19% in 1998, 16% in 2003 and 13% in 2008 and to remain constant thereafter.

5.6. Load Projections

The projections of electricity requirements for the four clients considered in the industrial sector, viz. large scale industries, small scale industries, Agriculture and Transport, are available from the results of Module 1 of the MAED model. But similar projections for the five clients considered in the Household/ Service sector, viz. lighting, cooling, air-conditioning, other electric appliances and Commercial, are not readily available from the output of Module 1. However, this information has, in fact, already been worked out for preparing the input data of Module 1 (see section 4.2.3, Chapter 4 for details).

Table 5.2. Consumption Share by Type of Client

		1992/93	1997/98	2002/03	2007/08	2012/13	2017/18	2022/23
Reference Scenario	**Industry/Transport:**							
	Agriculture	30	21	15	10	7	4	3
	Transport	1	1	1	1	1	1	1
	Small scale industry	10	10	9	8	7	7	6
	Large scale industry	59	68	75	81	85	88	90
	Household/Service:							
	Commercial	26	25	23	22	21	22	23
	Domestic Air-Conditioning	3	3	4	5	7	9	12
	Domestic Cooling	23	22	22	21	19	17	15
	Domestic Lighting	25	24	24	23	22	19	17
	Domestic Others	24	26	27	29	31	32	33
Optimistic Scenario	**Industry/Transport:**							
	Agriculture	30	21	14	8	5	3	2
	Transport	1	1	1	1	1	1	1
	Small scale industry	10	10	9	8	7	6	5
	Large scale industry	59	68	76	83	87	90	92
	Household/Service:							
	Commercial	26	25	23	21	21	22	22
	Domestic Air-Conditioning	3	3	5	6	8	12	16
	Domestic Cooling	23	22	21	20	17	15	12
	Domestic Lighting	25	24	23	22	19	16	13
	Domestic Others	24	26	28	31	34	36	37
Constrained Scenario	**Industry/Transport:**							
	Agriculture	30	21	16	12	9	7	6
	Transport	1	1	1	1	1	1	1
	Small scale industry	10	10	10	9	8	7	7
	Large scale industry	59	68	74	78	82	85	86
	Household/Service:							
	Commercial	26	26	26	26	26	26	26
	Domestic Air-Conditioning	3	3	3	3	3	3	3
	Domestic Cooling	23	23	23	23	23	23	23
	Domestic Lighting	25	25	25	25	25	25	25
	Domestic Others	24	24	24	24	24	24	24
Energy Efficiency Scenario	**Industry/Transport:**							
	Agriculture	30	21	14	9	6	4	3
	Transport	1	1	1	1	1	1	1
	Small scale industry	10	10	10	9	8	7	6
	Large scale industry	59	68	75	81	85	88	90
	Household/Service:							
	Commercial	26	24	23	21	20	20	0
	Domestic Air-Conditioning	3	3	5	6	8	11	14
	Domestic Cooling	23	22	22	21	19	17	15
	Domestic Lighting	25	24	23	22	20	17	14
	Domestic Others	24	26	28	30	33	35	37

The shares of various clients in different sectors as projected in the four scenarios are given in Table 5 2 It may be noted that in the Industry, Agriculture and Transport sectors, the share of large scale industries will grow from 59% now to around 90% in the terminal year in all the four scenarios, while the share of Agriculture decreases from 30% now to 2 - 6 % in the terminal year The share of small scale industries also decreases from 10% now to about 5 - 7 % in the terminal year while the share of transport remains constant at about 1% throughout the study period In the Household and Service sector, the share of Commercial consumption decreases while the share of other appliances in household increases in all scenarios except in the constrained scenario where both of these shares remain constant.

Using the above mentioned shares of various clients in the sectoral electricity demand and the assumed improvement in system losses along with the respective load modulation coefficients, the projected system peak demand worked out for the different scenarios is reported in Table 5.3 and Fig. 5.14. It may be noted that, the system peak demand in the Reference Scenario will increase from 7582 MW in 1993 to 83 552 MW in 2023 at an average annual growth rate of 8.3%. The system load factor in this case has been calculated to slightly decrease in the future years.

The system peak demand in the Optimistic Growth Scenario is projected to increase at 10.4% per annum over the study period, and is about 75% higher compared to that in the Reference Scenario in the year 2023. On the other hand, the system peak demand in the Constrained Scenario increases at about 6.5% per annum, from 7582 MW in 1993 to 49 416 MW in 2023.

In the case of the Energy Efficiency Scenario, where the economic growth is the same as that in the Reference Scenario, the peak demand is projected to increase from 7582 MW in 1993 to 67 485 MW in 2023, at an average annual growth rate of 7.6%. Thus, the same economic growth may be attained by considerably lower electricity demand and correspondingly lower generation capacity. Consequently, the investments required for electric system expansion will be smaller in this scenario compared to that for the Reference Scenario. However, additional funds would be required to implement conservation and efficiency improvement measures assumed in this scenario.

The selected parts of the output of the Modules 2 and 3 are given in Appendix D.

Table 5.3. Projected Peak Demand in Four Scenarios (MW)

YEAR	REFERENCE SCENARIO	OPTIMISTIC SCENARIO	CONSTRAINED SCENARIO	ENERGY EFFICIENCY SCENARIO
1993	7582	7582	7582	7582
1998	10 718	10 718	10 483	10 718
2003	16 026	17 222	14 923	15 017
2008	24 194	29 935	21 411	20 524
2013	37 502	51 752	32 319	28 394
2018	55 925	87 402	46 656	38 165
2023	83 552	146 038	49 416	67 485

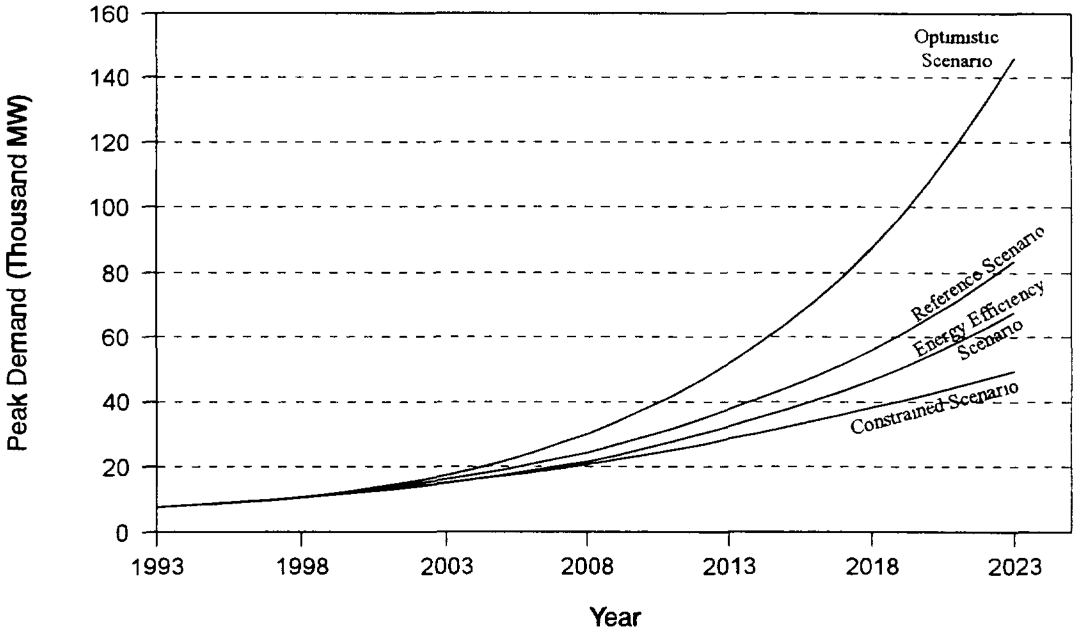


FIG 5 14 Projected Peak Demand in Four Scenarios

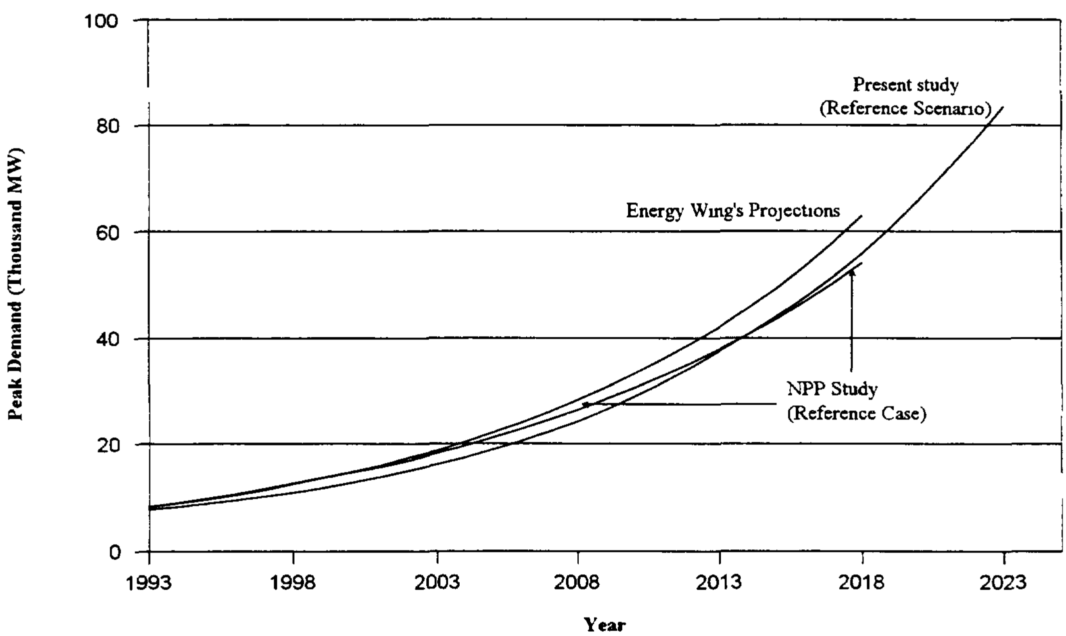


FIG. 5.15. Comparison of Projections of Electricity Peak Demand

5.7. Comparison with Other Projections

Official estimates of future peak demand are available for the next 10 years only According to these estimates, the system peak demand is expected to increase at about 11% p a during 1993-2003 [8] Other recent studies conducted in Pakistan on electricity demand projections [20, 78] have estimated that the system peak demand will grow at about 7 8-8 8% p a during 1993-2018

The results of the present study are compared with the projections of other studies in Fig 5 15 It may be noted that the peak demand projections for the Reference Scenario of the present study are almost in line with other projections The small differences among these projections are due to different values used for the estimated peak load (adjusted for load shedding) in the base year and different assumptions for future socioeconomic development

5.8. Conclusions

The above analysis has shown that the electricity peak demand is expected to grow at about 6 4%, 8 3% and 10 4% during the next 30 years corresponding to the three economic growth scenarios (Constrained, Planning Target and Optimistic) However, if the efficiency improvement potential can be realized, the economic growth of 7% p a (as in the Reference scenario) can be achieved with lower electricity demand Furthermore, the analysis has shown that the pattern of load can vary significantly if the shares of various end-use categories in total consumption change The detailed information to carry out this type of analysis is scanty Efforts should be made to collect data on electricity consumption pattern of various end-use categories Such an information can help to improve significantly the projections of electricity peak demand and pattern of system load curves

Chapter 6

ALLOCATION OF ENERGY SUPPLIES BETWEEN POWER AND NON-POWER SECTORS

6.1. Introduction

Electric power generation is responsible for some 37% of total primary energy consumption in Pakistan. Allocation of fossil fuels to this activity has to compete with the energy needs of other sectors. The limited supply of natural gas has been causing severe problems in its allocation to power and non-power sectors. As described in Chapter 4, the demand for electricity is expected to increase at a much higher rate than that of total energy. As a result, the primary energy needs for power generation will increase more rapidly than for other sectors, further exacerbating the problems of allocating limited fuels between power and non-power sectors.

This issue can be resolved by balancing simultaneously the demand and supply of the entire energy system. It is pertinent that while allocating various fuels to different sectors, factors such as, the prices of fuels, technical limitation of various sectors (i.e. motor fuel requirements of transport sector), deliverability of certain fuels (e.g. gas supplies through pipelines to rural areas) and user preferences are taken into account. Such an analytical framework is provided by the BALANCE module of ENPEP, which uses an equilibrium approach for balancing demand and supply of the entire energy system.

The "objective" of this component of the study, which has been carried out by using the BALANCE module of the ENPEP package, is to evaluate, by iteration between the BALANCE and ELECTRIC modules, that the optimal capacity expansion plan obtained from the ELECTRIC module analysis is consistent with the requirements of various fuels by the non-electric sector under the given set of assumptions about future availability of supplies of various fuels and their prices.

In the present analysis, the Reference Scenario energy demand which corresponds to the official perspective of economic development has been used for analysing two energy supply cases labeled here as Gas imports case and No gas imports case. This chapter describes the energy network for Pakistan; data and main assumptions used in the BALANCE analysis; study approach; and results of energy supply cases.

6.2. Energy Network

The energy supply and demand network of Pakistan designed for this study is shown in Fig. 6.1. Salient features of the network are:

(1) Electricity is not competing with any alternative fuel. This simplification permits the electricity demand to remain identical in the ELECTRIC and BALANCE modules and attention can be focused on analysing the distribution of limited resources between power and non-power sectors.

(2) The energy supply system includes not only the existing energy sources but also future energy supply options of imported gas and imported steam coal.

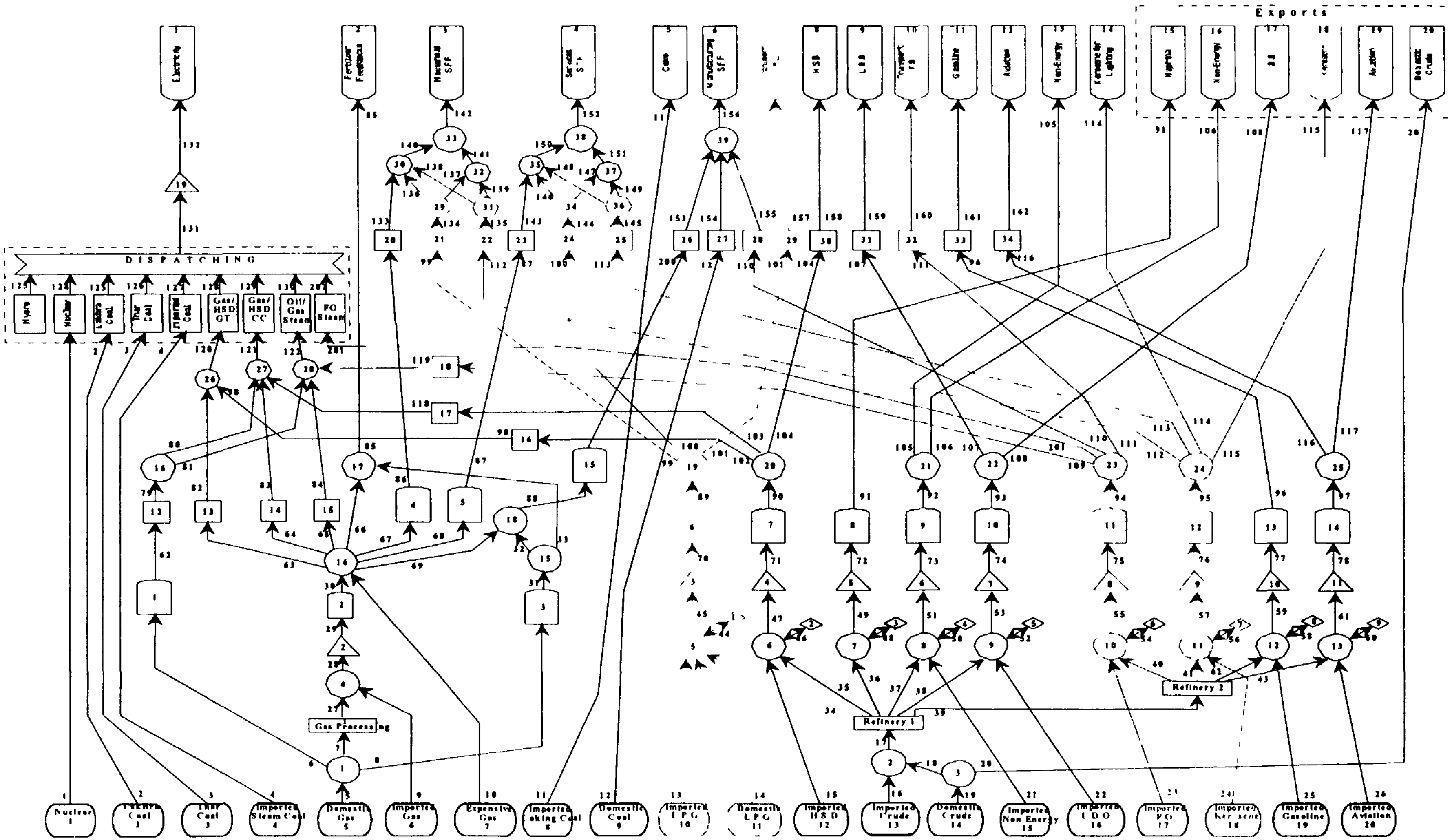


FIG. 6.1. Energy Network for Pakistan

(3) An expensive gas resource category has been considered to allow the model to find a solution (see Section 6.4 for the function of this resource in determining a solution).

(4) As in the base year about 25% of the indigenous gas produced was consumed as raw gas in the power sector and in the fertilizer industry, it has been assumed that the raw gas usage in these sectors will continue at the base year levels.

(5) In the BALANCE model an oil refinery can not have more than six outputs while the three existing refineries in Pakistan are producing more than six products. So the existing and future oil refineries have been modeled as a set of two refineries producing seven energy products (liquefied petroleum gas (LPG), light diesel oil (LDO), high speed diesel oil (HSD), kerosene, furnace oil (FO), gasoline and aviation) and two non-energy products (naphtha and non-energy products). The sizing of the refinery capacity has been linked to gasoline demand in view of its being the highest ex-refinery revenue earning product.

(6) Gas processing has been modeled as a conversion process. The processing losses (12.5% in 1993) are represented in the efficiency of the process.

(7) Transportation/transmission and distribution (T&D) of gas and oil products have been modeled as conversion processes with O&M costs representing the T&D costs and efficiencies representing the T&D losses. T&D of electricity has also been modeled as a conversion process but its efficiency has been changed over time to reflect reductions in T&D losses.

(8) In the electric sub-sector of the network nine types of electric plants based on different types of fuel or technology have been considered. According to this grouping Oil/Gas Steam plants represent the existing and committed plants which may be operated on FO or gas or on both fuels; FO Steam plants represent the candidate plants which will be operated only on FO; CC plants represent the combined cycle plants based on gas/HSD; GT plants represent the combustion turbines which can be operated on Gas/HSD; imported coal plants represent the future steam plants based on imported coal; Thar coal plants represent the future steam plants based on indigenous Thar coal; Lakhra coal plants represent existing and future fluidised bed combustion plants based on Lakhra coal; Nuclear power plants represent the existing, under construction and future nuclear power plants; and Hydro plants represent the existing, under construction and future hydro plants.

(9) The consumer prices of gas to power, manufacturing, households and services sectors are linked to the consumer price of FO based on current Government pricing policy.

(10) The network has been so constructed that substitutable fossil fuels (SFF) demand of manufacturing sector is met from FO, gas and domestic coal. As the demand for domestic coal is assumed to be for brick manufacturing only, supply limits have been imposed on domestic coal so that no coal in excess of the demand of brick kilns is supplied to the SFF demand of the Manufacturing sector. Therefore the real allocation decision regarding SFF

demand of Manufacturing is to determine the shares of FO and gas. The shares of gas, LPG and kerosene in SFF demand of the Household and Service sectors are determined not only by the relative prices of these fuels but also by their availability. So the SFF demands of these sectors are first divided between consumers which will potentially have access to piped gas and those which will not have access to piped gas, and then the SFF demands of these two groups are met by the available fuels based on their relative prices.

(11) Export of naphtha, non-energy oils, LDO, aviation and kerosene has been allowed to avoid building up of stocks and export of crude oil has been allowed to reflect the base year situation or any similar happening in future.

(12) In order to facilitate the transfer of energy flow data from the BALANCE module to the IMPACTS module, several dummy process nodes have been added prior to some final energy demand nodes and prior to allocation nodes of substitutable fossil fuels demand of the Household, Service and Manufacturing sectors. For the same reason dummy process nodes have also been added before the allocation nodes linking the power sector. (However, energy flows from BALANCE were not used for the IMPACTS analysis in the present study. In view of the scope of the study, only the power sector was analysed by the IMPACTS module and energy flows and other data were obtained from the ELECTRIC module).

6.3. Data and Main Assumptions

6.3.1. Energy Demand Projections

Energy demand projections of the Reference Scenario, in terms of final energy, derived from the MAED module of ENPEP, have been used as demand input. Table 6.1 gives the base year energy consumption and energy demand projections at five year intervals from 1998 to 2023. It may be noted that SFF demand of the Manufacturing, Household and Service sectors in the year 2023 will be 80.1 million TOE, 8.6 million TOE and 2.0 million TOE, respectively. These demands correspond to about 68% of the non-electric demand of the year 2023.

6.3.2. Electric Sector Data

The technical and economic data for the existing, committed and candidate thermal and hydro power plants used in the BALANCE study are the same as used for the ELECTRIC module. The Base year (i.e. 1993) average annual load duration curve (LDC) derived from the MAED study has been used as input for the electric sector of BALANCE. The LDC has been represented by the coefficients of a fifth degree polynomial. (The LDC and the associated coefficients are given in Fig. 6.2).

The "electric" part of the BALANCE model simulates the operation of the electricity generation plants (representing an optimal expansion plan derived from ELECTRIC module) in a very approximate manner e.g. (i) it considers only one average annual load duration curve for the entire study period, (ii) it considers the derated capacities of thermal power plants for estimating their generation and parameters like spinning reserves are not considered.

Table 6.1. Commercial Final Energy Demand Projections (Reference Scenario)

[MTOE]

	1992–93	1997–98	2002–03	2007–08	2012–13	2017–18	2022–23
Electricity	2.971	4.541	6.939	10.777	16.548	24.403	36.075
Household SFF	1.912	2.414	3.214	4.189	5.398	6.858	8.584
Kerosene for Lighting	0.402	0.378	0.309	0.154	0.000	0.000	0.000
Services SFF	0.577	0.725	0.927	1.148	1.412	1.674	1.983
Manufacturing SFF	7.089	10.804	16.560	24.901	36.612	54.206	80.050
Transport LPG	0.021	0.026	0.039	0.056	0.081	0.115	0.162
Total HSD	5.147	6.283	7.619	9.289	11.537	14.611	18.926
Total LDO	0.300	0.258	0.229	0.194	0.157	0.118	0.076
Transport FO	0.071	0.052	0.047	0.038	0.046	0.056	0.071
Total Gasoline	1.254	1.448	2.035	2.809	3.853	5.213	7.033
Total Aviation	0.428	0.553	0.714	0.928	1.219	1.626	2.203
Total Final Energy	20.172	27.481	38.631	54.484	76.864	108.881	155.164
Non-Energy Oil	0.415	0.618	0.830	1.122	1.531	2.104	2.910
Fertilizer Feedstocks	1.377	2.217	2.967	3.541	3.940	4.203	4.370
Coke	0.658	0.910	1.329	1.953	2.856	4.177	6.133
Total Energy & Non-energy uses	22.622	31.226	43.757	61.100	85.191	119.365	168.577

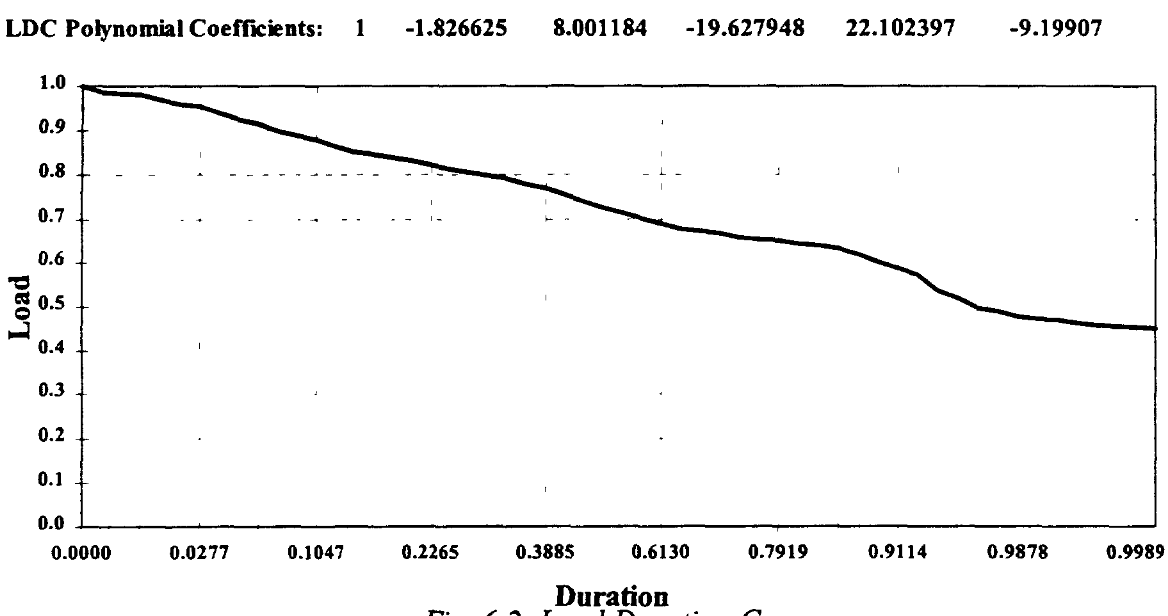


Fig. 6.2 Load Duration Curve

6.3.3. Energy Resources

6.3.3.1. Domestic energy resources

As discussed in Section 2.4 the indigenous proven fossil fuel reserves of Pakistan (as of mid-1994) correspond to: gas 23 trillion cubic feet (408 million TOE); oil 202 million barrels (27 million TOE) and coal 1075 million tons (481 million TOE).

Table 6.2. Exploratory Effort for Oil and Gas and Projected Production Profiles of Oil and Gas

1. Oil & Gas Exploration Effort During the Past 30 Years

	1963–1968	1968–1973	1973–1978	1978–1983	198–1988	1988–1993	1963–1993
Exploration Wells Drilled	15	13	17	25	74	90	234
Reserves of Oil discovered (Million TOE)	8.7	0.0	3.5	6.8	27.5	8.3	55.0
Reserves of Gas discovered (Million TOE)	0.8	1.8	58.8	6.7	31.0	100.2	199.4

2. Present Reserve/Production Ratios

	Oil	Gas
1992/93 Remaining Recoverable. Reserves (Million TOE)	27.3	406.9
1992/93 Production (Million TOE)	2.9	12.4
R/P (Years)	9.3	32.8

3. Scenario of Exploratory Effort and Discoveries of Additional Oil & Gas Resources Based on Petroleum Model

	1993–1998	1998–2003	2003–2008	2008–2013	2013–2018	2018–2023	1993–2023
Exploration Wells	142*	170	197	230	259	285	1283
Oil Reserves Discovered (Million TOE)	27.2	31.5	32.9	56.3	57.7	65.7	271.3
Gas Reserves Discovered (Million TOE)	107.0	109.3	211.8	120.4	178.4	191.8	918.6

4. Projected Oil & Gas Production Profiles

	1992–93	1997–98	2002–03	2007–08	202–13	2017–18	2022–23
Oil (Million TOE)	2.9	4.6	5.3	5.9	7.7	9.5	11.5
Gas (Million TOE)	12.4	16.1	24.2	32.7	39.9	43.2	45.1

* Eighth Plan Target.

Although the proven reserves of oil are very small while that of gas are modest, the estimated oil and gas resource potential is quite promising. It is believed that intensive exploration for oil and gas can lead to substantial addition of oil and gas reserves. As discussed in Section 3.4 of Chapter 3 and Appendix E, an Oil and Gas Model has been used to project production levels of indigenous oil and gas.

Table 6.2 gives: (i) The historical data of number of the oil and gas exploration wells drilled and the reserves of oil and gas discovered during the last 30 years, (ii) the status of current oil and gas reserves to production ratios, (iii) the assumed scenario of exploratory effort, the expected reserves of oil and gas discovered and (iv) the corresponding production levels of oil and gas. Oil and gas production is expected to increase from 2.9 million TOE and 12.4 million TOE in 1992–93 to 11.5 million TOE and 45.1 million TOE, respectively, by the year 2022–23.

The total coal resource potential of the country is estimated to be about 185 billion tons [14]. The recently discovered Thar coal field in the province of Sind accounts for about 95% of the coal resources. At present almost all of the domestic coal is being used for the manufacture of bricks. However, three 50 MW plants based on AFBC technology have been built to make use of the poor quality Lakhra coal resources. Although detailed quality analysis and mineability studies of Thar coal have not been carried out yet, it is expected that a significant electricity generation capacity (some 10 000 MW) may be based on this field during the next three decades. A part of the electricity generation capacity built on imported coal, may also be converted to Thar coal in later years, if found technically feasible. However, this possibility has not been considered in the BALANCE analysis. It has been assumed that the coal demand of the Manufacturing sector, would continue to be solely for meeting the requirements of the brick kiln industry. This demand is expected to increase at the rate of growth of the value added of the construction sector, and can all be met by indigenous coal resources. The demand of the 1150 MW AFBC plants is also assumed to be met from indigenous Lakhra coal resources.

Pakistan also has a sizable hydropower potential of about 30 000 MW of which some 4726 MW has already been developed and the electricity generation capacity expansion plan envisages additional hydro capacity of about 10 000 MW by the year 2022–23.

6.3.3.2. Imported energy supplies

During 1993 Pakistan imported about 4.1 million TOE of crude oil and 6.8 million TOE of oil products. HSD and FO were the major imported oil products, being 4.1 million TOE and 2.4 million TOE, respectively. About 0.7 million TOE of coking coal was also imported to meet the requirements of Pakistan Steel Mills at Karachi.

As already mentioned in Section 3.5 of Chapter 3, three gas pipeline projects for importing gas from Islamic Republic of Iran, Qatar and Turkmenistan are at various planning stages. The Islamic Republic of Iran–Pakistan gas pipeline project is at the most advanced planning stage and is expected to be commissioned by the year 2001. Commissioning dates of Pakistan–Qatar and Pakistan–Turkmenistan gas pipeline projects were initially assumed to be after a gap of few years i.e. 2007 and 2012, respectively [10, 79].

There are plans to build electricity generation plants based on imported coal, some of which may later be converted to utilize domestic coal.

6.3.4. Oil Refineries

Information about crude oil processed and products produced by the three oil refineries in Pakistan during 1992–93 is given in Table 6.3. Processing losses for the base year were about 3.5%. Furnace oil followed by HSD and motor spirit are the major oil products produced. The estimates of refinery O&M costs and capital costs vary within a wide range, e.g. O&M cost estimates vary from \$9–22/TOE of crude processed and capital costs vary from \$120–300/TOE of processing capacity depending upon the size and complexity of the refinery [44, 80, 81, and 82]. An O&M cost equal to \$23.2/TOE of crude processed, capital cost of \$200/TOE, profit factor of 20% and typical capacity of new refinery as 5 million TOE/year of crude input have been used to reproduce the base year ex-refinery product prices.

6.3.5. Energy Prices

Oil prices: The fundamental principle of oil product pricing in Pakistan is to recover all the costs, along with suitable profit and at least maintain the budgetary support from the sale of oil in the market (i.e. collect some taxes) [8]. Further, the consumer price of a given oil product is the same throughout the country. Detailed breakup of the components of the consumer prices of various oil products for 1992–93 is given in Table 6.4. It may be noted that: (i) the price of FO (\$93.4/TOE) is the lowest amongst the oil products, its T&D cost is also the lowest (\$8.9/TOE) and the tax component is also very small. (ii) Motor spirit and HOBC are the most heavily taxed items and their T&D cost is also relatively high (\$26.7/TOE). The consumer price of a given oil product is the same for all users irrespective of the fact whether the product was produced locally or imported. Assuming that T&D costs, as given in Table 6.4 reflect the actual experience in Pakistan, the effective taxes/subsidies for various oil products are different from those in Table 6.4 are given in Table 6.5.

The present average domestic crude oil price paid to the producers is not available but is known to be lower than the imported crude oil price due to various discounts received by the government. However, the present petroleum policy envisages that the prices of domestic crude oil delivered at the refinery gate shall be based on the C&F price of a comparable crude oil or a basket of Arabian/Persian Gulf crude oils plus or minus a quality differential between the basket and the local crude. No other adjustments or discount will apply [8]. In line with this policy the domestic crude oil price has been assumed to be the same as that of the imported crude.

As already discussed in Section 3.6 of Chapter 3, for the present study, based on [27, 34 and 35] the price of imported crude oil has been projected to increase at 1.0% p.a. in real terms during 1993–2000, at 2.0% p.a. during 2000–2010 and at 2.7% p.a. during 2010–2023. Imported oil product prices are generally related to the imported crude oil price (see Table 6.6 for the ratios of oil product prices to crude oil, in Pakistan, from 1981–1994). It may be noted that imported furnace oil price has been about three quarters of the imported crude oil price during 1988–1994. The prices of all oil products have been projected by assuming the same price growth rates as used for crude oil.

Table 6.3. Production of Oil Refineries In 1992–93

[TOE]

	Crude Oil Processed	Products										
		MS	HOBC	Kerosene	HSD	LDO	FO	Aviation Fuel	Naphtha	LPG	Non-Energy	Total
Attock Oil Refinery	1 255 134	414 189	0	137 099	272 213	3472	360 837	16 699	0	9565	21 835	1 235 909
Pakistan Refinery Ltd.	2 378 715	277 788	74 813	116 130	581 324	0	924 917	315 352	1233	14 481	3466	2 309 504
National Refinery Ltd.	2 923 283	333 212	677	274 237	575 121	297 759	463 831	261 613	104 461	14 963	460 695	2 786 569
Total	6 557 132	1 025 189	75 490	527 466	1 428 658	301 231	1 749 585	593 664	105 694	39 009	485 996	6 331 982
Products Slate		15.63%	1.15%	8.04%	21.79%	4.59%	26.68%	9.05%	1.61%	0.59%	7.41%	96.57%

Source: [14]

Table 6.4. Composition of the Consumer Prices* of Oil Products (1992–93)

Fuel	Ex-Refinery Price	Customs/ Excise Duty	Distribution Margin	Dealer's Commission	Prescribed Price	Inland Freight Margin	Development Surcharge	Consumer Price	Taxes	T&D Costs
	Rs./Litre									
HOBC	7.61	0.88	0.07	0.09	8.65	0.40	4.21	13.26	5.09	0.56
Motor Spirit	5.95	0.88	0.08	0.09	6.99	0.35	3.56	10.90	4.44	0.52
Kerosene	4.44	0.00	0.05	0.00	4.49	0.36	0.12	4.97	0.12	0.41
HSD	4.09	0.25	0.03	0.05	4.42	0.37	0.28	5.07	0.53	0.45
LDO	3.66	0.04	0.04	0.00	3.74	0.25	0.03	4.02	0.07	0.29
FO**	2088.68	35.20	16.81	0.00	2140.69	208.31	11.95	2360.95	47.15	225.12
	US $/TOE									
HOBC	367.75	42.50	3.18	4.35	417.77	19.29	203.43	640.48	245.93	26.81
Motor Spirit	306.00	45.29	4.03	4.63	359.93	18.01	183.02	560.97	228.31	26.67
Gasoline	313.60	44.94	3.92	4.60	367.09	18.17	185.55	570.82	230.49	26.69
Kerosene	213.09	0.00	2.23	0.00	215.34	17.27	5.91	238.52	5.91	19.50
HSD	182.31	11.14	1.28	2.23	196.96	16.49	12.64	226.09	23.78	20.00
LDO	158.66	1.73	1.68	0.00	162.07	10.83	1.24	174.14	2.97	12.51
FO	82.63	1.39	0.67	0.00	84.69	8.24	0.47	93.40	1.87	8.91

* Weighted average by days and one US $ = Rs. 25.9598
** Rs/Tonne

Source: [14]

Table 6.5. Effective Taxes/Subsidies on Oil Products (1992–93)

Product	Domestic		Imported		Av. Price ($/TOE)	T and D Costs ($/TOE)	Sale Price ($/TOE)	Tax/Subsidy ($/TOE)
	Quantity (TOE)	Price ($/TOE)	Quantity (TOE)	Price ($/TOE)				
HOBC	75 490	367.75	94 595	207.20	278.46	26.81	640.48	335.21
Kerosene	527 466	213.09	168 875	200.92	210.14	19.50	238.52	8.88
HSD	1 428 658	182.31	4 109 360	183.06	182.86	20.00	226.09	23.23
F.O.	1 749 584	82.63	2 383 344	95.69	90.16	8.91	93.4	–5.67
L.D.O					158.7	12.51	174.14	3.00
Non-Energy					285.4	37.9	562.3	239.00 *
LPG					161.77	53.62 *	248.83	33.44 *
Aviation					475.48	8.5 *	531.58	47.64 *
Naphtha					144.70	8.5 *	153.20	0.00

* Estimated

Table 6.6. Imported Crude Oil & Product Prices in Pakistan (1981–1994)

	1980–81	1981–82	1982–83	1983–84	1984–85	1985–86	1986–87	1987–88	1988–89	1989–90	1990–91	1991–92	1992–93	1993–94
1 Crude Oil														
Quantity (10^6 TOE)	4 177	4 544	4 328	4 439	4 018	3 925	3 838	3 930	3 730	3 615	4 246	4 213	4 133	4 333
Value (10^6 US$)	994 74	1139 3	989 23	916 41	842 62	602	422	460 2	391 1	411 15	633 49	542 97	526 99	457 77
($/TOE)	238 14	250 71	228 59	206 44	209 73	153 37	109 95	117 09	104 86	113 74	149 21	128 89	127 50	105 64
($/BBL)	33 76	35 54	32 40	29 26	29 73	21 74	15 58	16 60	14 86	16 12	21 15	18 27	18 07	14 97
2 Aviation fuel														
Quantity (10^6 TOE)	0 002	0 004	0 002	0 000	0 002	0 004	0 004	0 002	0 003	0 002	0 003	0 002	0 001	0 003
Value (10^6- US$)	1	2	1	0	1	2	0 6	0 6	1 3	0 70	1 95	0 84	0 64	1 1
($/TOE)	476 64	467 18	463 61	0 00	463 61	517 87	138 57	389 61	395 38	40 37	588 24	516 92	475 48	431 71
Ratio to Crude Oil	2 00	1 86	2 03	0 00	2 21	3 38	1 26	3 33	3 77	3 50	3 94	4 01	3 73	4 09
3 Kerosene														
Quantity (10^6 TOE)	0 389	0 364	0 402	0 424	0 504	0 507	0 576	0 595	0 629	0 773	0 430	0 058	0 169	0 123
Value (10^6- US$)	155	124	124	111	125	110	79	95 4	96 6	140 76	160 21	10 65	33 93	21 15
($/TOE)	398 11	341 08	308 18	261 67	247 82	216 91	137 19	160 43	153 50	182 14	372 58	185 19	200 92	172 62
Ratio to Crude Oil	1 67	1 36	1 35	1 27	1 18	1 41	1 25	1 37	1 46	1 60	2 50	1 44	1 58	1 63
4 HSD														
Quantity (10^6 TOE)	1 148	1 183	1 401	1 440	1 299	1 405	2 051	2 449	2 882	2 900	2 765	3 482	4 109	4 600
Value (10^6- US$)	409	373	399	346	297	241	250	341 8	387 9	454 43	750 94	648 59	752 25	705 55
($/TOE)	356 23	315 43	284 80	240 27	228 71	171 54	121 86	139 55	134 60	156 69	271 55	186 29	183 06	153 37
Ratio to Crude Oil	1 50	1 26	1 25	1 16	1 09	1 12	1 11	1 19	1 28	1 38	1 82	1 45	1 44	1 45
5 Furnace oil														
Quantity (10^6 TOF)	0	0	0	0 222	0 406	0 519	0 528	0 707	0 769	1 554	1 109	1 775	2 383	3 159
Value (10^6- US$)	0	0	0	42	73	64	50	63 3	59 8	137 63	133 8	160 54	228 07	254 38
($/TOE)	0 00	0 00	0 00	189 58	179 79	123 41	94 71	89 47	77 73	88 60	120 70	90 42	95 69	80 53
Ratio to Crude Oil	0 00	0 00	0 00	0 92	0 86	0 80	0 86	0 76	0 74	0 78	0 81	0 70	0 75	0 76
6 HOBC														
Quantity (10^6 TOE)	0 072	0 083	0 119	0 125	0 128	0 091	0 119	0 132	0 165	0 199	0 128	0 087	0 095	0 055
Value (10^6 US$)	30	29	37	35	31	16	16	19 4	24	31 68	39 98	19 98	19 6	9 42
($/TOE)	419 53	347 78	309 75	280 96	242 42	176 03	133 91	146 95	145 25	159 38	312 49	229 30	207 20	169 84
Ratio to Crude Oil	1 76	1 39	1 36	1 36	1 16	1 15	1 22	1 26	1 39	1 40	2 09	1 78	1 63	1 61
7 Motor Spirit														
Quantity (10^6 TOE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0 060
Value (10^6 US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	9 69
($/TOE)	–	–	–	–	–	–	–	–	–	–	–	–	–	161 69
Ratio to Crude Oil	–	–	–	–	–	–	–	–	–	–	–	–	–	1 53
8 Gasoline														
Quantity (10^6 TOE)	0 072	0 083	0 119	0 125	0 128	0 091	0 119	0 132	0 165	0 199	0 128	0 087	0 095	0 115
Value (10^6- US$)	30	29	37	35	31	16	16	19 4	24	31 68	39 98	19 98	19 6	19 11
($/TOE)	419 53	347 78	309 75	280 96	242 42	176 03	133 91	146 95	145 25	159 38	312 49	229 30	207 20	165 61
Ratio to Crude Oil	1 76	1 39	1 36	1 36	1 16	1 15	1 22	1 26	1 39	1 40	2 09	1 78	1 63	1 57

Source [14]

Gas prices: According to the present petroleum policy [8] the principle for determining the consumer price of natural gas will be to relate it to the price of fuel oil and to ensure that the overall average price of natural gas is at par with the domestic price of fuel oil for industrial and power sectors; above par with the domestic price of fuel oil for commercial sector; and at par with the border price of fuel oil for the households sector.

Regarding the price of gas for fertilizer sector, the price for feedstock use is proposed to be determined as per contractual commitments. Table 6.7 gives consumer prices of gas in the base year and on 14th June, 1995. It may be noted that gas prices for industry and power sector are the same, the price for households is about 30% lower and the price for services sector is about 12.5% higher than the price for industry.

The consumer prices of gas have been increased substantially since 1993 and the prices effective from 14th June, 1995, are higher by about 30% over the 1992–93 price levels, if considered in US $. (The consumer prices of oil products have also been increased since 1993 but to a lesser extent. The June 1995 consumer price of FO was about $100/TOE)

In order to enhance exploration and development of gas resources the producer price for gas will be indexed to the C&F price of a basket of imported Arabian/Persian Gulf crude oils depending upon the exploration zone (77.5% of crude oil price for zone 1, 72.5% for zone 2 and 67.5% for zone 3). Based on this policy it has been assumed that on average the new gas discovered will be priced at 75% of the crude oil price, which is about the same as the price of FO.

Table 6.7. Consumer Prices of Gas

	1992–93		Effective from 14 June, 1995	
	(Rs./1000CFT)	(US $/TOE)[4]	(Rs./1000CFT)	(US$/TOE)[4]
(i) Gas to Households[1]	38.75	63.8	59.36	82.4
First slab	31.00	51.0	40.27	55.9
Second slab	n.a	n.a	48.14	66.8
Third slab	n.a	n.a	65.72	91.2
Fourth slab	46.50	76.6	78.45	108.9
(ii) Gas to Services	61.41	101.1	94.56	131.2
(iii) Gas to Industry	54.57	89.8	84.05	116.6
(iv) Gas to Power	54.72[2]	90.1	84.05	116.6
(v) Raw Gas to Power		56.2		
(vi) Gas to Fertilizer	32.44[3]	55.6[3]		

1 Average of first and last slabs

2 Charges per unit volume of gas are same as for industries but there is an additional commodity charge.

3 Average price of gas to fertilizer industry in SNGPL system

4 Exchange rates of Rs. 25 96/US$ in 1992–93 and Rs. 30.80 /US$ in June, 1995. have been assumed

Source Based on [14, 21 and 45]

The price of already discovered/existing domestic gas, for simplicity, has also been assumed to be the same as the price of FO. The price of imported natural gas has been taken equivalent to the price of imported furnace oil [20]. In line with the present pricing policy it has been assumed that: the consumer price of gas in the manufacturing and power sectors will be the same as the domestic FO price; in the households sector the consumer price of gas will be equal to the border price of FO; and in the services sector consumer price of gas will be 1.125 times the domestic price of FO.

Coal Prices: Coal prices in Pakistan are not regulated by the government. Based on [14], the average selling price of coal produced in the public sector, at the mine, was about $58/TOE. The transportation cost estimates for domestic coal are not available, a value of $32/TOE (higher than the maximum T&D cost for oil products) has been assumed for coal used in the brick kilns.

The domestic coal fired AFBC plants based on Lakhra coal will be built close to the mines. These mines will be large scale mechanized mines and coal production costs of these mines will be higher. A cost of $108/TOE, including local transportation costs, has been assumed for coal supplied to AFBC power plants. It has been assumed that domestic coal-fired steam plants based on Thar coal will also be located close to the mine. Based on [20], a cost of $68/TOE was assumed for the Thar coal. A real escalation of 1% p.a. for the next three decades has been assumed in the production and transportation cost of domestic coal.

The price of imported steam coal has been taken as $84/TOE ($55.3/ton) in 1993. This price has been assumed to increase by 1% p.a. for the next three decades to reflect increased mining and transportation costs because of increasingly stringent environmental standards worldwide. The price of imported coking coal has been assumed to be 10% higher than the imported steam coal price based on [33]. The future prices of coking coal are assumed to follow the same trend as those of imported steam coal.

6.3.6. Gas Allocation Policy:

During the 7th Plan period (1988–1993) and until 1994 the allocation of gas to different consumers was made by the Government of Pakistan (GOP) on the basis of the following priorities:

- Feedstock for fertilizer industry;
- Replacement of HSD in power generation (year round requirements only);
- Replacement of kerosene in the domestic sector;
- Replacement of kerosene in the commercial sector;
- Replacement of FO in the industrial sector; and
- Substitution of FO in power generation.

Since 1994, for the purpose of providing various incentives for oil and gas exploration, the GOP has divided the country, along with its offshore areas, into three prospectivity zones. Zone 1 being high risk and high cost; Zone 2 being medium risk and medium cost; and Zone 3 being low to medium risk and low cost [78]. According to the current petroleum policy the role of GOP in making the allocation of gas to various consumers will be limited to new gas discoveries in Zone 3 only. (The Task Force on Energy [78] has recommended that any gas discovered in Zone 3 should be injected in the pipeline system and first priority for pipeline gas should be given to the domestic sector. For the remaining available quantity, after honouring all the existing commitments in respect of fertilizer and other industrial sectors, no priority should be fixed). The producers of gas in the Zones 1 and 2 will be free to dispose off the gas as they wish.

Keeping in view the pre-1994 and current gas allocation policy, it has been assumed that all the feedstock requirements of the fertilizer industry and more than 90% of the SFF demand of households (as in the base year) will be met from gas supplies. For the Service sector, it has been assumed that the share of gas in the SFF demand of this sector will increase gradually from some 60% in the base year to about 80% by the end of study year. The remaining available quantity of gas will be shared between the Manufacturing and Power sectors.

6.4. Study Approach

The BALANCE model uses long run supply curve coefficients to represent depletable resource prices. Such resource curves are not available for Pakistan, therefore resource price data have been entered as a single value representing intercepts of the supply curves. Such a representation of pricing data leads to situations in which the limits on some links may not be respected and the model does not converge. The approach used to overcome this difficulty has been to introduce a hypothetical resource of very high cost which limits the excess use of scarce resource and forces the model to converge.

Further, in order to reflect the current policy of the government for the consumer prices of gas in different sectors, various options available in the model to modify the prices at different nodes have been used. According to the above referred to policy the delivered price of gas for the power sector and industries has to be set equivalent to FO prices.

The "input price reference link" option in the pricing node 2 (see Fig. 6.1) has been used to attain the consumer price of gas for power and industry sectors same as the consumer price of FO . As the consumer price of gas in the Household sector is lower than the consumer price of gas for Industry by an amount equal to the inland transportation cost of FO so "price addition" option in pricing node 4 has been used to get the required consumer price for Households. Further, the "price multiplier" option in pricing node 5 has been used to increase the delivered price of gas to Service sector by 12.5%.

The most important fuel allocation decisions in the network are related to meeting SFF demand of Manufacturing sector (allocation node 39), SFF demand of Households (allocation node 33), SFF demand of Services sector (allocation nodes 38), and gas/oil demand of power sector (allocation nodes 26, 27 and 28).

The SFF demand of the Manufacturing sector is much higher than the sum of SFF demands of the Household and Service sectors and the feedstock requirements of the fertilizer industry. The BALANCE module has been used for simulating the distribution of gas in various sectors in such a way that after meeting the gas demand of households and services sectors and fertilizer feedstock requirements the remaining quantity of gas is approximately equally shared between the power and the manufacturing sector. Since the BALANCE model does not allow the premium multipliers to change with time, in order to regulate the use of gas with time in the manufacturing sector, a price node (15) with time varying price multipliers has been used for simulating the use of gas in the manufacturing sector.

For the Household sector it has been assumed that even with the current Government policy of providing gas to maximum number of households a significant fraction of urban and most of the rural population will remain unconnected to the national gas network and will have to rely on the use of kerosene and LPG. It has been assumed that the present share of kerosene and LPG in the SFF demand of the households (about 7%), representing the population unconnected to the gas grid, will remain constant and in the remaining SFF demand of households the three fuels will compete on the basis of their relative prices.

Similarly for the Services sector it has been assumed that the base year share of kerosene and LPG in the SFF demand, about 40%, representing services sector establishments unconnected to the gas grid will decline with time and in the remaining SFF demand of this sector, gas, kerosene and LPG will compete on the basis of their relative prices. The "MSHARE" program (an auxiliary programme of BALANCE) has been used to estimate the price sensitivity and premium multiplier coefficients for allocation nodes 26 and 28. (The combination of price sensitivity and premium multiplier parameters for various allocation nodes can be obtained from base year data of consumer prices, fuel shares, maximum capacity limits (if any) and priorities (if any) by using the "MSHARE" programme, instead of using judgmental values). For allocation node 27 price sensitivity and premium multiplier values have been used judgmentally.

6.5. Model Results

6.5.1. Gas Imports Case

In the light of the assumptions about the availability of indigenous and imported fuels, discussed in Section 6.3.3, and the Government's gas and oil pricing policies mentioned in Section 6.3.5 and gas allocation policy discussed in Section 6.3.6, the power system expansion plan formulated using ELECTRIC module was analysed by using the BALANCE module. The initial BALANCE results indicated that due to assumed availability of imported gas from the year 2001 a significantly higher gas-fired capacity could be added to the system compared to that envisaged in the initial ELECTRIC results. Several ELECTRIC and BALANCE iterations were carried out to formulate a power system expansion plan for which the fuels demanded by both sectors (power and non-power) and the fuel supplies are in balance.

The first imported gas pipeline project is expected to be commissioned in the year 2001, while the commissioning schedule of second and third projects is undetermined so far. The present analysis has indicated that with the given assumptions of energy demand and development of indigenous energy resources the second and third gas pipelines may be required in the years 2010 and 2016, respectively.

According to the final iteration results of BALANCE, for the Gas imports case, the primary energy demand will grow at about 7.1% p.a. during the next three decades, which is essentially equal to the projected economic growth rate. The shares by fuel in the year 2022 will be: Oil 31.6%; Gas 33.7%; Coal 19.8%; Hydro 5.8% and Nuclear 9.1%. The dependence on imported fuels will increase from the base year level of 32% to 35% and 48% in years 1997 and 2022, respectively (see Table 6.8 and Fig. 6.3).

Table 6.8. Gas Imports Case: Primary Energy Demand

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Domestic Oil	3 02	3 48	3 86	4 24	4 55	4 77	5 00	5 09	5 39	5 57	5 67	5 77	6 15	6 15	6 16
Imported Oil*	10 20	10 37	11 81	12 63	14 12	14 83	15 48	15 91	10 73	10 59	11 07	11 91	12 34	13 42	14 35
Domestic Gas	12 41	13 06	13 24	14 00	14 76	16 09	17 78	19 30	20 91	22 52	24 23	25 74	27 44	29 34	31 04
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	8 34	8 02	8 15	9 05	9 79	10 75	11 73
Domestic Coal	2 16	2 33	2 53	2 73	2 96	3 20	3 41	3 65	3 91	4 21	4 51	4 83	5 18	5 57	6 07
Imported Coal	0 66	0 70	0 75	0 80	0 85	0 91	0 98	2 07	2 07	2 16	2 20	3 15	3 18	3 26	3 53
Hydro	5 04	4 83	5 03	5 03	5 03	5 30	5 30	5 30	5 30	6 99	7 20	7 20	7 36	8 36	8 56
Nuclear	0 11	0 11	0 11	0 11	0 11	0 11	0 67	0 67	0 67	0 67	1 65	1 65	2 63	2 63	3 61
Total Primary Energy	33 60	34 88	37 33	39 53	42 37	45 20	48 62	51 99	57 32	60 73	64 68	69 28	74 06	79 47	85 05
Shares (%)															
Domestic Oil	9 0	10 0	10 3	10 7	10 7	10 6	10 3	9 8	9 4	9 2	8 8	8 3	8 3	7 7	7 2
Domestic Gas	36 9	37 4	35 5	35 4	34 8	35 6	36 6	37 1	36 5	37 1	37 5	37 1	37 0	36 9	36 5
Domestic Coal	6 4	6 7	6 8	6 9	7 0	7 1	7 0	7 0	6 8	6 9	7 0	7 0	7 0	7 0	7 1
Hydro	15 0	13 8	13 5	12 7	11 9	11 7	10 9	10 2	9 2	11 5	11 1	10 4	9 9	10 5	10 1
Nuclear	0 3	0 3	0 3	0 3	0 3	0 2	1 4	1 3	1 2	1 1	2 6	2 4	3 6	3 3	4 2
Total domestic fuels	67 7	68 3	66 4	66 0	64 7	65 2	66 1	65 4	63 1	65 8	66 9	65 2	65 8	65 5	65 2
Imported Oil*	30 3	29 7	31 6	31 9	33 3	32 8	31 8	30 6	18 7	17 4	17 1	17 2	16 7	16 9	16 9
Imported Gas	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	14 6	13 2	12 6	13 1	13 2	13 5	13 8
Imported Coal	2 0	2 0	2 0	2 0	2 0	2 0	2 0	4 0	3 6	3 6	3 4	4 5	4 3	4 1	4 2
Total imported fuels	32 3	31 7	33 6	34 0	35 3	34 8	33 9	34 6	36 9	34 2	33 1	34 8	34 2	34 5	34 8

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Domestic Oil	6 16	6 17	6 36	6 94	7 32	7 70	8 18	8 65	8 84	9 60	9 99	10 37	10 76	10 86	11 34
Imported Oil*	15 55	16 57	17 85	18 42	19 62	20 60	21 87	23 18	24 82	25 91	28 08	36 61	46 35	55 04	65 82
Domestic Gas	32 74	34 44	36 15	38 14	39 55	39 94	40 70	41 45	42 20	42 58	43 15	43 53	43 91	44 48	44 67
Imported Gas	11 48	12 23	15 76	16 93	18 12	20 87	23 51	25 08	31 16	34 11	36 60	37 62	37 62	37 62	37 62
Domestic Coal	6 51	7 15	7 61	8 18	9 67	11 27	12 85	14 47	16 23	18 94	21 67	24 67	26 54	30 36	33 73
Imported Coal	3 61	3 94	4 81	5 88	7 02	7 77	8 37	10 17	10 02	10 06	11 64	13 60	13 96	14 35	14 77
Hydro	10 92	11 25	10 96	11 71	12 53	13 36	14 18	14 18	14 18	14 18	14 18	14 18	14 18	14 18	14 18
Nuclear	4 59	5 57	6 55	7 53	8 51	9 49	10 47	11 45	12 43	13 41	14 39	16 24	18 20	20 16	22 12
Total Primary Energy	91 57	97 31	106 05	113 72	122 33	131 00	140 13	148 63	159 89	168 80	179 70	196 82	211 51	227 04	244 25
Shares (%)															
Domestic Oil	6 7	6 3	6 0	6 1	6 0	5 9	5 8	5 8	5 5	5 7	5 6	5 3	5 1	4 8	4 6
Domestic Gas	35 8	35 4	34 1	33 5	32 3	30 5	29 0	27 9	26 4	25 2	24 0	22 1	20 8	19 6	18 3
Domestic Coal	7 1	7 3	7 2	7 2	7 9	8 6	9 2	9 7	10 2	11 2	12 1	12 5	12 5	13 4	13 8
Hydro	11 9	11 6	10 3	10 3	10 2	10 2	10 1	9 5	8 9	8 4	7 9	7 2	6 7	6 2	5 8
Nuclear	5 0	5 7	6 2	6 6	7 0	7 2	7 5	7 7	7 8	7 9	8 0	8 2	8 6	8 9	9 1
Total domestic fuels	66 5	66 4	63 8	63 7	63 4	62 4	61 6	60 7	58 7	58 5	57 5	55 4	53 7	52 9	51 6
Imported Oil*	17 0	17 0	16 8	16 2	16 0	15 7	15 6	15 6	15 5	15 3	15 6	18 6	21 9	24 2	26 9
Imported Gas	12 5	12 6	14 9	14 9	14 8	15 9	16 8	16 9	19 5	20 2	20 4	19 1	17 8	16 6	15 4
Imported Coal	3 9	4 0	4 5	5 2	5 7	5 9	6 0	6 8	6 3	6 0	6 5	6 9	6 6	6 3	6 0
Total imported fuels	33 5	33 6	36 2	36 3	36 6	37 6	38 4	39 3	41 3	41 5	42 5	44 6	46 3	47 1	48 4

* (Including Expensive Gas treated as FO) Domestic oil includes LPG produced from gas fields

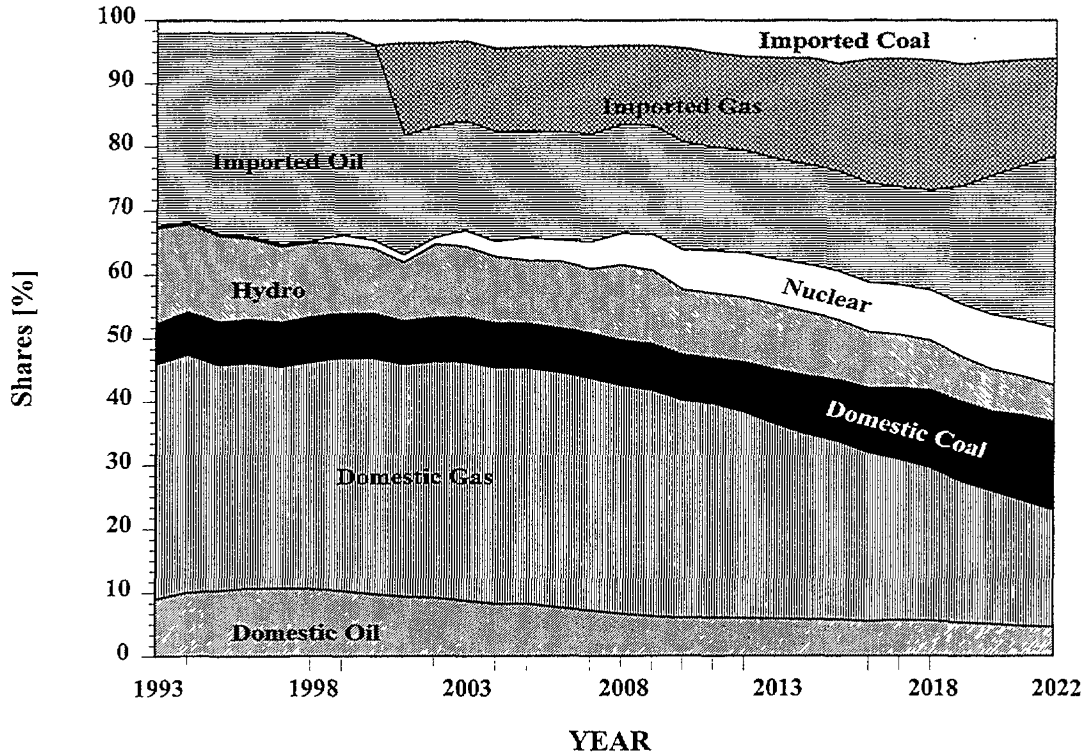


FIG. 6.3. Shares of Domestic and Imported Fuels in the Primary Energy Demand for the Gas Imports Case

Natural gas is a preferred fuel in the Manufacturing, Household and Services sectors and its shares in the SFF demand of these sectors in the base year were 51%, 93% and 60%, respectively. As already stated in section 6.3.5, according to the present pricing policy the consumer price of gas in the Manufacturing sector will be the same as the delivered price of FO to this sector. In such a case the BALANCE model will allocate equal shares to gas and FO in the manufacturing sector. However, because of factors such as: higher efficiency of gas compared to FO; convenience of use; being environmentally lesser polluting than FO, industrial consumers have a marked preference for gas. This preference for gas in the Manufacturing sector is reflected by a higher share of gas compared to FO in the base year. Table 6.9 gives the simulated shares of fuels in the SFF demand of Manufacturing, Household and Services sectors. It may be noted that the share of gas in the Manufacturing sector initially declines gradually to a level of 44% in the year 2000 and from the year 2001, when the imported gas becomes available, the share of gas remains at a level of about 57–62% till the year 2018, and in the period 2019–2022, when the gas availability becomes limited again, the share declines to 45% in order to maintain a demand and supply BALANCE over the energy network.

In the Household sector the consumer price of gas (about $64/TOE in 1993) is much lower than the prices of its competing fuels i.e. LPG ($249/TOE in 1993) and kerosene ($239/TOE in 1993). If the allocation of fuels in this sector were to be made entirely on the basis of prices then LPG and kerosene shares would be essentially negligible in this sector in future. So as mentioned in Section 6.4, the network has been modeled in such a way that the collective share of LPG and kerosene in the Household sector remain constant at a level of about 7–8% throughout the planning period.

Table 6.9. Gas Imports Case: Shares of Fuels in Substitutable Fossil Fuels Demand of Manufacturing, Households and Services Sectors

[%]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Manufacturing															
1 Gas*	50.9	47.3	43.0	42.8	40.9	43.0	45.0	44.2	56.5	56.5	56.6	56.9	57.1	57.3	57.4
2 F O	18.7	22.6	27.1	27.6	29.8	27.9	26.5	27.7	15.9	16.5	16.8	16.9	17.0	17.2	17.4
3 Coal	30.4	30.2	29.9	29.6	29.3	29.1	28.6	28.0	27.6	27.1	26.6	26.2	25.9	25.5	25.2
Households															
1 Gas	92.7	92.6	92.6	92.5	92.5	92.4	92.3	92.4	92.5	92.5	92.6	92.6	92.6	92.6	92.6
2 LPG	4.6	3.8	3.5	3.3	3.3	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1
3 Kerosene**	2.7	3.5	3.9	4.2	4.3	4.4	4.4	4.4	4.4	4.3	4.3	4.3	4.3	4.3	4.3
Services															
1 Gas	59.9	62.7	63.1	63.7	64.3	64.9	65.7	66.5	67.5	68.5	69.4	70.2	70.8	71.5	72.2
2 LPG	6.5	10.6	13.0	14.1	14.4	14.5	14.3	14.1	13.6	13.3	12.9	12.6	12.3	12.0	11.6
3 Kerosene	33.6	26.8	23.9	22.2	21.3	20.7	20.1	19.5	18.9	18.2	17.7	17.2	16.9	16.5	16.2
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Manufacturing															
1 Gas*	57.6	55.3	61.1	61.2	61.3	61.5	61.6	59.4	62.0	58.7	58.0	55.4	52.1	48.7	44.7
2 F O	17.6	20.1	14.6	14.7	14.8	14.9	15.0	17.5	15.1	18.6	19.6	22.4	26.0	29.6	33.8
3 Coal	24.8	24.6	24.3	24.1	23.9	23.7	23.4	23.2	22.9	22.7	22.4	22.2	22.0	21.7	21.5
Households															
1 Gas	92.6	92.6	92.6	92.6	92.6	92.6	92.6	92.6	92.6	92.6	92.6	92.4	92.2	92.1	91.8
2 LPG	3.1	3.1	3.1	3.0	3.0	3.0	3.0	3.0	2.9	2.9	2.9	2.9	3.0	3.0	3.1
3 Kerosene**	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.8	4.9	5.1
Services															
1 Gas	72.9	73.4	74.0	74.6	75.1	75.8	76.3	76.8	77.3	77.8	78.2	78.3	78.1	78.0	77.6
2 LPG	11.3	11.0	10.7	10.4	10.2	9.8	9.6	9.2	9.0	8.7	8.5	8.3	8.3	8.3	8.4
3 Kerosene	15.8	15.5	15.2	15.0	14.7	14.4	14.2	14.0	13.7	13.5	13.3	13.4	13.6	13.7	14.0

* Excluding gas used as feedstocks in Fertilizer industry
** Excluding kerosene for lighting

In the Services sector, similar to the Household sector, the price of gas ($101/TOE in 1993) is much lower than the prices of its competing fuels i.e. LPG and kerosene. So the network has been modeled in such a way that the collective share of LPG and kerosene does not drop below about 20% (i.e. half the base year value). The simulated fuel shares for the Household and Service sectors are also given in Table 6.9.

The demand of gas for fertilizer feedstocks; for SFF demand of Manufacturing, Household and Services sectors; and for the power sector along with available supplies of gas are given in Table 6.10. In the "Available Supply minus Demand" row the numbers with negative sign show the usage of Expensive Gas and rounding errors. It may be noted that:

- Until the year 2001 supply of gas is barely adequate to meet demand;
- It takes about 8 years for the first imported gas pipeline, about 5 years for the second imported gas pipeline and only 3 years for the third imported gas pipeline capacity to be fully utilized.
- In the period 2020–2022 the gas supplies are inadequate to meet demand;
- Gas usage in the manufacturing and power sectors may be increased during 2001–2014, however, beyond 2015 the gas availability position will be very tight again, even with the availability of the third gas pipeline.

The inputs to power generation by source are given in Table 6.11. It may be noted that:

- The share of hydro generation drops from about 40% in 1993 to only 13% by 2022.
- At present about 33% generation is based on gas. When imported gas becomes available in 2001, its share increases to 65% but then gradually declines to less than the base year level by 2022.
- The share of domestic and imported coal increases gradually from essentially zero to 25% by 2022.
- The share of nuclear power reaches a level of 20% in the terminal years.

6.5.2. No Gas Imports case

As mentioned in Section 3.5 the pipeline investment cost of all the projects for import of gas through pipeline from various countries of the region have yet to be firmly established through feasibility studies, the gas purchase prices have yet to be negotiated and, in addition, there are political risks involved. So for energy supply analysis a case envisaging no import of gas has also been considered.

After a few iterations between BALANCE and ELECTRIC modules, as expected, it was found that gas allocation to power and non-power sector will be at much lower levels. As such, significantly lower electricity generation capacity, as compared to Gas imports case, could be based on gas. According to the final simulation of BALANCE module for the No gas imports case, the primary energy demand will be slightly higher (247 million TOE in the year 2022) compared to 244 million TOE in the Gas imports case due to lower efficiency of steam plants compared to combined cycle plants. Further, although the level of import dependence in the two cases will be nearly the same the quantity of oil imports in No gas imports case will be much higher (106 million TOE in the year 2022) compared to 66 million TOE in the corresponding year in Gas imports case. This will imply the construction of larger infrastructure for transportation of oil, construction of additional refineries for refining of oil and greater atmospheric emissions (see Fig. 6.4 and Table 6.12 for mix of primary energy sources in this case).

Table 6.13 gives the shares of various fuels in the substitutable fossil fuels demand of Manufacturing, Household and Services sectors for the No gas imports case. A comparison with Gas imports case (see Table 6.9) shows that for the Household and Service sectors the shares of gas are essentially the same in both cases because of the modeling of allocation of these two sectors. As regards the SFF demand of manufacturing sector the share of gas in No imports case are much lower, in the year 2001–2022, compared to the Gas imports case.

A comparison of gas supply and demand balance for the two cases (see Tables 6.10 and 6.14) indicates that in the No gas imports case 32–40% of gas supplies are allocated to power sector during the years 2001–2022 while in the Gas imports case in the corresponding period some 41–48% of the gas supplies can be allocated to power sector. In terms of relative quantities the level of gas use in power sector is 88% higher in 2003, 77% higher in 2013 and 140% higher in year 2022 in the Gas imports case compared to the No gas imports case. When the imported gas option will not be available additional FO based steam plants will be built to meet the capacity generation requirements. Table 6.15 gives the shares of primary fuels in electricity generation in this case. The share of oil in power generation in No gas imports case reaches a level of 25–32% in the period 2018–2022 compared to a level of only 3–13% in the corresponding period in the Gas imports case. However, the shares of hydro, coal and nuclear in electricity generation by source are essentially similar in both cases.

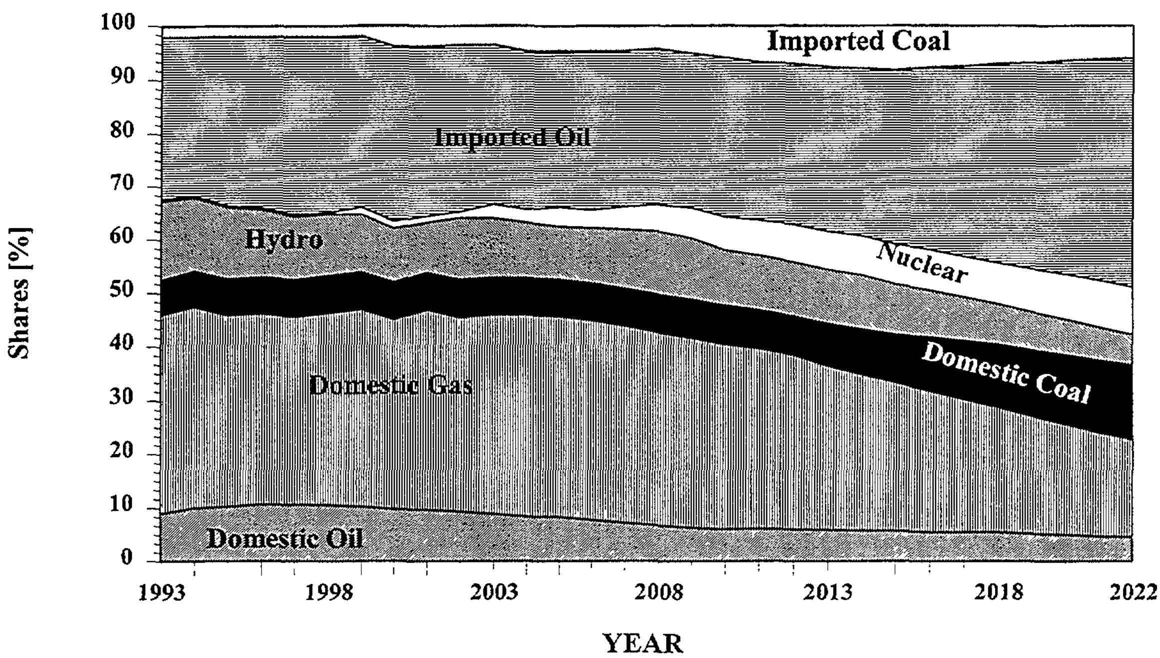


FIG. 6.4. Shares of Domestic and Imported Fuels in the Primary Energy Demand for the No Gas Imports Case

Table 6.10. Gas Imports Case: Gas Supply and Demand

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Net Gas Supply*:															
Domestic Gas	11 13	11 69	11 84	12 50	13 15	14 30	15 76	17 06	18 45	19 84	21 31	22 61	24 08	25 71	27 18
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	8 22	7 90	8 03	8 91	9 64	10 59	11 55
Total	11 13	11 69	11 84	12 50	13 15	14 30	15 76	17 06	26 67	27 74	29 34	31 52	33 72	36 30	38 73
Imported Gas Available	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	12 54	12 54	12 54	12 54	12 54	12 54	12 54
Gas Demand															
Services	0 34	0 39	0 41	0 43	0 46	0 48	0 51	0 54	0 58	0 62	0 66	0 69	0 73	0 77	0 81
Household	1 77	1 86	1 95	2 04	2 13	2 23	2 37	2 50	2 65	2 81	2 98	3 14	3 31	3 50	3 69
Manufacturing	3 61	3 65	3 61	3 91	4 06	4 65	5 30	5 67	7 90	8 60	9 38	10 23	11 14	12 12	13 19
Feedstocks	1 38	1 51	1 66	1 83	2 01	2 21	2 34	2 48	2 63	2 79	2 96	3 07	3 18	3 29	3 41
Total Non-Power	7 09	7 40	7 62	8 20	8 66	9 58	10 52	11 20	13 77	14 82	15 98	17 14	18 36	19 68	21 10
Power	4 02	4 29	4 41	4 48	4 73	4 97	5 34	5 99	12 90	12 92	13 36	14 39	15 35	16 62	17 64
Total Gas Demand	11 12	11 69	12 04	12 69	13 39	14 55	15 86	17 19	26 67	27 74	29 34	31 52	33 71	36 30	38 73
Available Supply–Demand	0 01	–0 01	–0 19	–0 19	–0 24	–0 25	–0 10	–0 13	4 32	4 64	4 52	3 63	2 90	1 95	0 99

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net Gas Supply*:															
Domestic Gas	28 65	30 12	31 58	33 30	34 52	34 85	35 50	36 15	36 80	37 13	37 62	37 95	38 27	38 76	38 93
Imported Gas	11 31	12 04	15 53	16 68	17 84	20 56	23 16	24 70	30 70	33 60	36 05	37 06	37 05	37 05	37 05
Total	39 96	42 16	47 11	49 98	52 36	55 41	58 66	60 86	67 50	70 73	73 67	75 00	75 33	75 82	75 99
Imported Gas Available	12 54	12 54	25 08	25 08	25 08	25 08	25 08	25 08	37 62	37 62	37 62	37 62	37 62	37 62	37 62
Gas Demand															
Services	0 86	0 90	0 94	0 99	1 04	1 10	1 14	1 19	1 24	1 29	1 34	1 39	1 43	1 48	1 52
Household	3 89	4 09	4 30	4 52	4 76	5 01	5 25	5 51	5 78	6 07	6 36	6 65	6 94	7 24	7 55
Manufacturing	14 36	14 90	17 77	19 23	20 82	22 54	24 44	25 46	28 74	29 46	31 46	32 53	33 02	33 38	33 13
Feedstocks	3 53	3 61	3 69	3 77	3 85	3 93	3 98	4 03	4 09	4 14	4 19	4 23	4 26	4 29	4 33
Total Non-Power	22 63	23 50	26 70	28 52	30 47	32 57	34 81	36 19	39 84	40 95	43 36	44 79	45 64	46 39	46 53
Power	17 33	18 66	20 41	21 46	21 90	22 84	23 85	24 97	27 65	29 77	30 31	30 65	30 66	30 75	30 92
Total Gas Demand	39 96	42 16	47 11	49 97	52 36	55 41	58 66	61 16	67 50	70 73	73 67	75 44	76 30	77 13	77 44
Net Supply–Demand	1 23	0 50	9 56	8 40	7 24	4 52	1 92	0 08	6 93	4 02	1 57	0 13	–0 41	–0 75	–0 89

* Excluding Processing Losses of Domestic Gas and Transport and Distribution Losses of Domestic and Imported Gas

Table 6.11. Gas Imports Case: Inputs to Power Generation by Source

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Hydro	5.04	4.83	5.03	5.03	5.03	5.30	5.30	5.30	5.30	6.99	7.20	7.20	7.36	8.36	8.56
Gas	4.02	4.29	4.41	4.48	4.73	4.97	5.34	5.99	12.90	12.92	13.36	14.39	15.35	16.62	17.64
Imported Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.01	0.93	0.92	0.87	1.71	1.63	1.58	1.72
Domestic Coal	0.00	0.00	0.02	0.02	0.04	0.05	0.05	0.05	0.06	0.09	0.10	0.11	0.13	0.17	0.29
Oil	3.10	3.14	3.49	4.27	5.04	5.58	6.02	5.51	0.04	0.05	0.04	0.04	0.05	0.07	0.06
Nuclear	0.11	0.11	0.11	0.11	0.11	0.11	0.67	0.67	0.67	0.67	1.65	1.65	2.63	2.63	3.61
Total	12.27	12.37	13.06	13.91	14.95	16.01	17.38	18.52	19.89	21.64	23.22	25.10	27.15	29.42	31.89
Shares (%)															
Hydro	41.1	39.0	38.5	36.2	33.6	33.1	30.5	28.6	26.6	32.3	31.0	28.7	27.1	28.4	26.8
Gas	32.8	34.7	33.8	32.2	31.6	31.0	30.7	32.3	64.9	59.7	57.5	57.3	56.5	56.5	55.3
Imported Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	4.7	4.3	3.8	6.8	6.0	5.4	5.4
Domestic Coal	0.0	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.9
Oil	25.2	25.4	26.7	30.7	33.7	34.8	34.7	29.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Nuclear	0.9	0.9	0.9	0.8	0.7	0.7	3.9	3.6	3.4	3.1	7.1	6.6	9.7	8.9	11.3

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Hydro	10.92	11.25	10.96	11.71	12.53	13.36	14.18	14.18	14.18	14.18	14.18	14.18	14.18	14.18	14.18
Gas	17.33	18.66	20.41	21.46	21.90	22.84	23.85	24.97	27.65	29.77	30.31	30.65	30.66	30.75	30.92
Imported Coal	1.65	1.83	2.54	3.43	4.37	4.92	5.29	6.84	6.43	6.18	7.47	9.09	9.09	9.09	9.09
Domestic Coal	0.33	0.53	0.53	0.61	1.56	2.60	3.57	4.54	5.61	7.58	9.50	11.66	12.61	15.46	17.79
Oil	0.06	0.13	0.14	0.25	0.27	0.35	0.35	0.39	0.96	1.39	2.63	3.31	7.47	10.34	14.53
Nuclear	4.59	5.57	6.55	7.53	8.51	9.49	10.47	11.45	12.43	13.41	14.39	16.24	18.20	20.16	22.12
Total	34.88	37.97	41.13	44.98	49.14	53.55	57.71	62.38	67.26	72.52	78.48	85.12	92.20	99.97	108.61
Shares (%)															
Hydro	31.3	29.6	26.6	26.0	25.5	24.9	24.6	22.7	21.1	19.6	18.1	16.7	15.4	14.2	13.1
Gas	49.7	49.1	49.6	47.7	44.6	42.7	41.3	40.0	41.1	41.1	38.6	36.0	33.2	30.8	28.5
Imported Coal	4.7	4.8	6.2	7.6	8.9	9.2	9.2	11.0	9.6	8.5	9.5	10.7	9.9	9.1	8.4
Domestic Coal	0.9	1.4	1.3	1.3	3.2	4.9	6.2	7.3	8.3	10.4	12.1	13.7	13.7	15.5	16.4
Oil	0.2	0.3	0.4	0.6	0.5	0.6	0.6	0.6	1.4	1.9	3.4	3.9	8.1	10.3	13.4
Nuclear	13.2	14.7	15.9	16.7	17.3	17.7	18.1	18.4	18.5	18.5	18.3	19.1	19.7	20.2	20.4

Table 6.12. No Gas Imports Case: Primary Energy Demand

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Domestic Oil	3 02	3 48	3 86	4 24	4 55	4 77	5 00	5 09	5 39	5 57	5 67	5 77	6 15	6 16	6 16
Imported Oil*	10 20	10 37	11 81	12 63	14 12	14 85	15 50	16 94	17 62	18 62	19 08	20 30	21 52	23 52	24 78
Domestic Gas	12 41	13 06	13 24	14 00	14 76	16 09	17 78	18 23	20 66	21 63	23 72	25 74	27 44	29 34	31 04
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Domestic Coal	2 16	2 33	2 53	2 73	2 96	3 18	3 40	3 63	3 91	4 22	4 51	4 83	5 18	5 58	6 05
Imported Coal	0 66	0 70	0 75	0 80	0 85	0 91	0 98	2 00	2 09	2 18	2 28	3 32	3 41	3 69	3 83
Hydro	5 04	4 83	5 03	5 03	5 03	5 30	5 30	5 30	5 30	6 99	7 20	7 20	7 36	8 36	9 56
Nuclear	0 11	0 11	0 11	0 11	0 11	0 11	0 67	0 67	0 67	0 67	1 65	1 65	2 63	2 63	3 61
Total Primary Energy	33 60	34 88	37 33	39 53	42 37	45 20	48 63	51 86	55 63	59 87	64 10	68 80	73 69	79 27	85 03
Shares (%)															
Domestic Oil	9 0	10 0	10 3	10 7	10 7	10 6	10 3	9 8	9 7	9 3	8 9	8 4	8 3	7 8	7 2
Domestic Gas	36 9	37 4	35 5	35 4	34 8	35 6	36 6	35 2	37 1	36 1	37 0	37 4	37 2	37 0	36 5
Domestic Coal	6 4	6 7	6 8	6 9	7 0	7 0	7 0	7 0	7 0	7 1	7 0	7 0	7 0	7 0	7 1
Hydro	15 0	13 8	13 5	12 7	11 9	11 7	10 9	10 2	9 5	11 7	11 2	10 5	10 0	10 5	11 2
Nuclear	0 3	0 3	0 3	0 3	0 3	0 2	1 4	1 3	1 2	1 1	2 6	2 4	3 6	3 3	4 2
Total domestic fuels	67 7	68 3	66 4	66 0	64 7	65 1	66 1	63 5	64 6	65 3	66 7	65 7	66 2	65 7	66 4
Imported Oil*	30 3	29 7	31 6	31 9	33 3	32 8	31 9	32 7	31 7	31 1	29 8	29 5	29 2	29 7	29 1
Imported Gas	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Imported Coal	2 0	2 0	2 0	2 0	2 0	2 0	2 0	3 9	3 8	3 6	3 6	4 8	4 6	4 7	4 5
Total imported fuels	32 3	31 7	33 6	34 0	35 3	34 9	33 9	36 5	35 4	34 7	33 3	34 3	33 8	34 3	33 6

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Domestic Oil	6 16	6 17	6 36	6 94	7 32	7 71	8 18	8 65	8 85	9 61	10 00	10 38	10 76	10 86	11 33
Imported Oil*	26 65	28 27	31 44	33 50	36 71	40 46	44 13	49 12	55 19	61 69	69 48	77 17	85 87	95 61	106 31
Domestic Gas	32 74	34 44	36 15	37 91	39 55	39 92	40 70	41 45	42 20	42 58	43 15	43 53	43 91	44 21	44 67
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Domestic Coal	6 58	7 12	7 76	8 30	8 82	10 31	11 92	13 53	16 28	18 98	21 71	24 60	27 70	30 90	34 00
Imported Coal	3 91	5 14	6 31	7 50	8 71	9 92	11 16	12 41	12 68	12 96	13 27	13 60	13 96	14 35	14 77
Hydro	10 92	11 25	10 96	11 71	12 53	13 36	14 18	14 18	14 18	14 18	14 18	14 18	14 18	14 18	14 18
Nuclear	4 59	5 57	6 55	7 53	8 51	9 49	10 47	11 45	12 43	13 41	14 39	16 24	18 20	20 16	22 12
Total Primary Energy	91 57	97 96	105 53	113 38	122 15	131 17	140 73	150 81	161 80	173 42	186 18	199 70	214 57	230 26	247 38
Shares (%)															
Domestic Oil	6 7	6 3	6 0	6 1	6 0	5 9	5 8	5 7	5 5	5 5	5 4	5 2	5 0	4 7	4 6
Domestic Gas	35 8	35 2	34 3	33 4	32 4	30 4	28 9	27 5	26 1	24 6	23 2	21 8	20 5	19 2	18 1
Domestic Coal	7 2	7 3	7 4	7 3	7 2	7 9	8 5	9 0	10 1	10 9	11 7	12 3	12 9	13 4	13 7
Hydro	11 9	11 5	10 4	10 3	10 3	10 2	10 1	9 4	8 8	8 2	7 6	7 1	6 6	6 2	5 7
Nuclear	5 0	5 7	6 2	6 6	7 0	7 2	7 4	7 6	7 7	7 7	7 7	8 1	8 5	8 8	8 9
Total domestic fuels	66 6	65 9	64 2	63 8	62 8	61 6	60 7	59 2	58 1	57 0	55 6	54 5	53 5	52 2	51 1
Imported Oil*	29 1	28 9	29 8	29 5	30 1	30 8	31 4	32 6	34 1	35 6	37 3	38 6	40 0	41 5	43 0
Imported Gas	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Imported Coal	4 3	5 2	6 0	6 6	7 1	7 6	7 9	8 2	7 8	7 5	7 1	6 8	6 5	6 2	6 0
Total imported fuels	33 4	34 1	35 8	36 2	37 2	38 4	39 3	40 8	41 9	43 0	44 4	45 5	46 5	47 8	48 9

* (Including Expensive Gas treated as FO). Domestic oil includes LPG produced from gas fields.

Table 6.13. No Gas Imports Case: Shares of Fuels in Substitutable Fossil Fuels Demand of Manufacturing, Households and Services Sectors [%]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Manufacturing															
1 Gas*	50 9	47 3	42 5	42 2	40 1	41 5	43 4	45 3	44 9	44 0	43 1	42 1	39 2	37 8	37 4
2 F O	18 7	22 6	27 6	28 2	30 6	29 5	28 0	26 6	27 5	28 9	30 3	31 7	35 0	36 7	37 4
3 Coal	30 4	30 2	29 9	29 6	29 3	29 1	28 6	28 0	27 6	27 1	26 6	26 2	25 9	25 5	25 2
Households															
1 Gas	92 7	92 6	92 6	92 5	92 5	92 4	92 5	92 5	92 5	92 5	92 5	92 5	92 5	92 5	92 5
2 LPG	4 6	3 8	3 5	3 3	3 3	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2
3 Kerosene**	2 7	3 5	3 9	4 2	4 3	4 3	4 3	4 3	4 3	4 3	4 3	4 3	4 4	4 4	4 4
Services															
1 Gas	59 9	62 7	63 1	63 9	64 4	65 1	66 0	66 9	67 6	68 5	69 3	70 0	70 5	71 1	71 8
2 LPG	6 5	10 6	13 0	13 9	14 3	14 3	14 2	13 8	13 6	13 3	13 0	12 6	12 4	12 2	11 8
3 Kerosene	33 6	26 8	23 9	22 2	21 4	20 5	19 8	19 2	18 8	18 2	17 7	17 4	17 1	16 8	16 4

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Manufacturing															
1 Gas*	37 9	36 9	35 3	35 6	34 6	32 5	31 3	28 7	27 5	25 7	23 1	21 7	20 8	18 6	17 3
2 F O	37 3	38 6	40 4	40 3	41 5	43 9	45 3	48 2	49 6	51 6	54 5	56 1	57 3	59 7	61 2
3 Coal	24 8	24 6	24 3	24 1	23 9	23 7	23 4	23 2	22 9	22 7	22 4	22 2	22 0	21 7	21 5
Households															
1 Gas	92 5	92 5	92 4	92 4	92 4	92 4	92 3	92 3	92 2	92 1	92 1	92 1	92 1	92 1	92 0
2 LPG	3 1	3 1	3 1	3 1	3 1	3 1	3 1	3 1	3 1	3 1	3 1	3 0	3 0	3 0	3 0
3 Kerosene**	4 4	4 4	4 4	4 5	4 5	4 5	4 6	4 6	4 7	4 8	4 8	4 8	4 9	4 9	5 0
Services															
1 Gas	72 5	73 0	73 6	74 2	74 7	75 2	75 6	75 9	76 2	76 6	77 0	77 4	77 6	78 0	78 2
2 LPG	11 5	11 2	10 9	10 6	10 3	10 0	9 8	9 6	9 4	9 2	8 9	8 7	8 6	8 3	8 2
3 Kerosene	16 0	15 8	15 5	15 2	15 0	14 7	14 6	14 5	14 4	14 3	14 1	13 9	13 8	13 7	13 7

* Excluding gas used as feedstocks in Fertilizer industry
** Excluding kerosene for lighting

Table 6.14. No Gas Imports Case: Gas Supply and Demand

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Net Gas Supply*:															
Domestic Gas	11 13	11 69	11 84	12 50	13 15	14 30	15 76	16 14	18 24	19 07	20 87	22 61	24 08	25 71	27 18
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Total	11 13	11 69	11 84	12 50	13 15	14 30	15 76	16 14	18 24	19 07	20 87	22 61	24 08	25 71	27 18
Imported Gas Available	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Gas Demand															
Services	0 34	0 39	0 41	0 43	0 46	0 48	0 51	0 55	0 58	0 62	0 66	0 69	0 73	0 77	0 81
Household	1 77	1 86	1 95	2 04	2 13	2 24	2 37	2 51	2 66	2 81	2 98	3 14	3 31	3 49	3 68
Manufacturing	3 61	3 65	3 57	3 86	3 99	4 49	5 11	5 81	6 28	6 70	7 15	7 57	7 64	8 00	8 60
Feedstocks	1 38	1 51	1 66	1 83	2 01	2 21	2 34	2 48	2 63	2 79	2 96	3 07	3 18	3 29	3 41
Total Non-Power	7 09	7 40	7 59	8 15	8 58	9 41	10 34	11 35	12 15	12 92	13 74	14 47	14 86	15 55	16 49
Power	4 02	4 29	4 42	4 51	4 77	5 02	5 47	4 79	6 09	6 14	7 13	8 31	9 47	10 33	10 87
Total Gas Demand	11 12	11 69	12 00	12 66	13 35	14 43	15 80	16 14	18 24	19 07	20 87	22 78	24 32	25 88	27 36
Available Supply-Demand	0 01	-0 01	-0 16	-0 17	-0 20	-0 13	-0 05	0 00	0 00	0 00	0 00	-0 17	-0 24	-0 17	-0 18

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net Gas Supply*:															
Domestic Gas	28 65	30 12	31 58	33 10	34 52	34 84	35 50	36 15	36 80	37 13	37 62	37 95	38 27	38 53	38 93
Imported Gas	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Total	28 65	30 12	31 58	33 10	34 52	34 84	35 50	36 15	36 80	37 13	37 62	37 95	38 27	38 53	38 93
Imported Gas Available	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Gas Demand															
Services	0 85	0 89	0 94	0 99	1 04	1 09	1 13	1 18	1 22	1 27	1 32	1 37	1 42	1 48	1 53
Household	3 88	4 08	4 29	4 52	4 75	5 00	5 24	5 49	5 76	6 04	6 33	6 62	6 92	7 24	7 57
Manufacturing	9 44	9 93	10 26	11 17	11 74	11 91	12 41	12 29	12 75	12 92	12 53	12 76	13 17	12 74	12 82
Feedstocks	3 53	3 61	3 69	3 77	3 85	3 93	3 98	4 03	4 09	4 14	4 19	4 23	4 26	4 29	4 33
Total Non-Power	17 70	18 51	19 18	20 44	21 37	21 92	22 76	22 99	23 82	24 36	24 37	24 98	25 77	25 75	26 25
Power	11 13	11 73	12 42	12 66	13 40	12 91	12 87	13 20	13 20	13 23	13 41	13 00	12 74	12 78	12 87
Total Gas Demand	28 83	30 24	31 60	33 10	34 77	34 83	35 64	36 19	37 02	37 59	37 79	37 98	38 51	38 53	39 12
Net Supply-Demand	-0 18	-0 13	-0 01	0 00	-0 25	0 00	-0 13	-0 04	-0 21	-0 46	-0 16	-0 03	-0 24	0 00	-0 19

* Excluding Processing Losses of Domestic Gas and Transport and Distribution Losses of Domestic and Imported Gas

Table 6.15. No Gas Imports Case: Inputs to Power Generation by Source

[MTOE]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Hydro	5.04	4.83	5.03	5.03	5.03	5.30	5.30	5.30	5.30	6.99	7.20	7.20	7.36	8.36	9.56
Gas	4.02	4.29	4.42	4.51	4.77	5.02	5.47	4.79	6.09	6.14	7.13	8.31	9.47	10.33	10.87
Imported Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.94	0.95	0.94	0.95	1.89	1.86	2.02	2.02
Domestic Coal	0.00	0.00	0.02	0.02	0.04	0.03	0.03	0.03	0.06	0.10	0.10	0.11	0.14	0.18	0.27
Oil	3.10	3.14	3.48	4.24	5.00	5.55	5.92	6.79	6.84	6.80	6.19	5.97	5.72	6.01	5.78
Nuclear	0.11	0.11	0.11	0.11	0.11	0.11	0.67	0.67	0.67	0.67	1.65	1.65	2.63	2.63	3.61
Total	12.27	12.37	13.06	13.91	14.95	16.01	17.38	18.53	19.90	21.64	23.22	25.12	27.17	29.53	32.11
Shares (%)															
Hydro	41.1	39.0	38.5	36.2	33.6	33.1	30.5	28.6	26.6	32.3	31.0	28.6	27.1	28.3	29.8
Gas	32.8	34.7	33.8	32.4	31.9	31.3	31.5	25.9	30.6	28.4	30.7	33.1	34.8	35.0	33.9
Imported Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	4.8	4.4	4.1	7.5	6.8	6.8	6.3
Domestic Coal	0.0	0.0	0.2	0.2	0.3	0.2	0.2	0.2	0.3	0.5	0.4	0.5	0.5	0.6	0.9
Oil	25.2	25.4	26.6	30.5	33.4	34.7	34.0	36.7	34.4	31.4	26.7	23.8	21.0	20.4	18.0
Nuclear	0.9	0.9	0.9	0.8	0.7	0.7	3.9	3.6	3.4	3.1	7.1	6.6	9.7	8.9	11.2

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Hydro	10.92	11.25	10.96	11.71	12.53	13.36	14.18	14.18	14.18	14.18	14.18	14.18	14.18	14.18	14.18
Gas	11.13	11.73	12.42	12.66	13.40	12.91	12.87	13.20	13.20	13.23	13.41	13.00	12.74	12.78	12.87
Imported Coal	1.96	3.03	4.04	5.05	6.06	7.07	8.08	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09
Domestic Coal	0.40	0.50	0.68	0.73	0.71	1.64	2.64	3.61	5.65	7.62	9.55	11.58	13.77	16.00	18.06
Oil	6.03	6.04	6.94	7.89	8.62	10.01	10.78	12.46	14.68	17.51	20.61	23.95	27.46	31.17	35.62
Nuclear	4.59	5.57	6.55	7.53	8.51	9.49	10.47	11.45	12.43	13.41	14.39	16.24	18.20	20.16	22.12
Total	35.03	38.13	41.58	45.55	49.83	54.47	59.01	63.99	69.23	75.04	81.23	88.04	95.43	103.37	111.93
Shares (%)															
Hydro	31.2	29.5	26.4	25.7	25.2	24.5	24.0	22.2	20.5	18.9	17.5	16.1	14.9	13.7	12.7
Gas	31.8	30.8	29.9	27.8	26.9	23.7	21.8	20.6	19.1	17.6	16.5	14.8	13.4	12.4	11.5
Imported Coal	5.6	7.9	9.7	11.1	12.2	13.0	13.7	14.2	13.1	12.1	11.2	10.3	9.5	8.8	8.1
Domestic Coal	1.1	1.3	1.6	1.6	1.4	3.0	4.5	5.6	8.2	10.1	11.8	13.2	14.4	15.5	16.1
Oil	17.2	15.8	16.7	17.3	17.3	18.4	18.3	19.5	21.2	23.3	25.4	27.2	28.8	30.2	31.8
Nuclear	13.1	14.6	15.8	16.5	17.1	17.4	17.7	17.9	18.0	17.9	17.7	18.4	19.1	19.5	19.8

6.6. Conclusions

The BALANCE analysis has clearly shown that:

(1) In spite of vigorous efforts assumed for the exploitation of indigenous resources of oil, gas, coal and hydro, the energy import dependence of the country will increase in the coming years. Although the share of imported fuels will remain between 32–38% of the total commercial primary energy supplies during the next 20 years, the level of energy imports will increase from 11 million TOE to 21 million TOE by the end of the 9th Five Year Plan (2003) and further to 49 million TOE by the year 2013. This implies that exploitation of all indigenous energy resources and development of nuclear technology have to be pursued with vigorous effort so that the country's economy is protected from possible shocks due to fluctuations in the international energy prices.

(2) The most constrained fuel is natural gas which is also the most preferred fuel by several categories of consumers due to its convenience of use, environmental advantages (compared to other fossil fuels) and higher efficiency of use. Only a small quantity of gas from indigenous sources can be allocated to the power sector after meeting the essential requirements of non-power sector. In the No gas imports case the allocation of gas to power sector can be increased from 4.0 million TOE in 1993 to only 7.1 million TOE in 2003 and about 13.0 million TOE from the year 2013 to 2022. However, if imported gas is available then the allocation of gas to power sector can be increased from 4.0 million TOE in 1993 to 13.4 million TOE in 2003 and about 31.0 million TOE in the year 2022.

(3) During the next three decades all the assumed capacity (4.8 billion cft per day, about 136 million m^3/day) of the three planned gas pipeline projects will be required, and the appropriate commissioning dates of second and third gas pipeline projects, under the given projections of energy demand and assumed developments of indigenous resources, may be 2010 and 2016. Thus there is a need to ensure that these projects come on line as indicated and at envisaged costs.

(4) In addition to the large demand of indigenous coal in the power sector, a large amount of indigenous coal may also be used in the manufacturing sector in addition to the coal demand of brick kilns. This will help in further reducing dependence on imported fuels. Thus efforts should be enhanced to develop large scale economic mines of coal for use in large scale industries, e.g. cement, etc.

In addition to the application of BALANCE described in this Chapter, this model can also be used for analysing several other energy sector issues such as impact of energy prices on demand and supply, and effectiveness of energy conservation measures.

Chapter 7

ELECTRICITY GENERATION SYSTEM EXPANSION ANALYSIS

7.1. Introduction

Power system expansion planning involves consideration of a number of technical, economic and system reliability factors which make it a fairly complex activity. Availability of a large number of alternative technologies with varying economic and operational characteristics and their availability at different time horizons make the decision making process for capacity expansion even more complicated. Longer construction periods; uncertain load growth, cost and availability of fuels; and expensive pollution control equipment must also be taken into consideration when a planner is deciding the number, type, and size of generating units to be installed. A number of planning tools are available for power system expansion studies. Among these the IAEA's model WASP (Wien automatic system planning package) is the most commonly used tool in developing countries. It has been used in Pakistan for the last 20 years. The objective of WASP is to determine the generating system expansion plan that adequately meets demand for electric power at minimum cost while respecting user-specified constraints. WASP is designed for medium to long term planning, beyond a 10 year time horizon, and is intended to address a number of critical issues in generation planning, including generating unit size, system reliability, details of the existing system, seasonal variation in loads and hydroelectric availability, and appropriate simulation of future system operation. It utilises probabilistic simulation to estimate system production costs, unserved energy and reliability; and dynamic programming for optimization of system expansion policies. WASP is organised in a modular way which permits the user to monitor intermediate results, avoiding waste of valuable computer time due to possible input data errors.

For the purpose of present study, the ELECTRIC module (WASP-III Plus version) of ENPEP has been used to workout alternative plans for future expansion of power system over the next 30 years. A Reference Case expansion plan and a number of alternative plans have been studied. This chapter describes the input information used for these analyses, discusses the alternative power system expansion plans formulated and analyses the implications of implementation of such plans.

7.2. Use of WASP in Pakistan

The Pakistan Atomic Energy Commission (PAEC) has been using WASP since 1974, when it was used for conducting a long term nuclear power planning study for Pakistan [68]. Since then the model has been extensively used in various studies carried out by PAEC. The model was transferred to WAPDA in 1984 where it has been used for a number of studies, e.g. for preparation of the Master Plan for Power Sector in 1985, for the Lakhra study in 1986, for the study of Kalabagh hydro power project in 1987 and recently for formulation of the long term National Power Plan in 1994. PAEC has been providing technical assistance to WAPDA and the Energy Wing for the use of WASP and has been closely associated with a number of studies carried out by WAPDA using this model. The Energy Wing of the Planning Commission is using WASP for evaluation of power sector expansion plans since 1988.

7.3. Preparation of Input Data

Most of the technical data used for the formulation of electricity generation system expansion plans for the present study are based on the publications of the power utilities, viz. WAPDA and KESC. The data used for the present analysis are discussed below.

7.3.1. General Information

In Pakistan five year economic development plans are formulated at regular intervals along with long term perspective plans covering a period of 15 years. Power sector plans are part of these Five Year Plans and the Perspective Plans. The most recent year for which complete information is available on the inputs required for the formulation of electricity generation system expansion plans is 1993. The time horizon for the present study has been selected to span over six five year plans (1993–2022). In view of large variation in hydro generation, each year has been divided into six periods. Further three hydroconditions namely dry, average and wet have been considered to represent year-to-year variations in hydrological conditions. On the basis of historical data of river inflows, probabilities of occurrence for these hydroconditions have been worked out as 30%, 40% and 30% for dry, average and wet years, respectively. Based on the storage capacities of hydro power plants, the plants have been divided into two categories: HYD1 and HYD2. HYD1 type plants are capable of large storage capacities while the HYD2 type plants are run-of-river type, having smaller storage capacities originally or due to silting of the plant reservoir have resulted in smaller storage capacities. The data on general background information are given in Table 7.1.

7.3.2. Load Forecast

The load forecast used for the present study has been estimated using the IAEA model MAED as discussed in Chapter 5. The projections of peak load, electricity generation and annual load factor for the planning period in the Reference Case are given in Table 7.2. The period load duration curves for each of the six periods of the base year, as well as for the future years have been worked out using Module 3 of MAED as discussed in Chapter 5.

Table 7.1 General Data and Background Information

Data item	Value
Study Period(first year-last year)	1993–2022
Number of periods per year	6
Number of hydroconditions	3
Probability of each hydrocondition	
Hydrocondition 1	30%
Hydrocondition 2	40%
Hydrocondition 3	30%
Basis for the conduct of study	
Constant/ current prices	Constant prices
Cost reference data	1992–93
Exchange rate	Pak. Rs.29.9598/US$

Table 7.2 Load Forecast

(Reference Case)

YEAR	PEAK LOAD (MW)	ENERGY (GW·h)	LOAD FACTOR (%)
1993	7582	48 733	73.37
1994	8125	52 226	73.37
1995	8708	55 970	73.37
1996	9332	59 983	73.37
1997	10 001	64 283	73.37
1998	10 718	68 842	73.32
1999	11 616	74 609	73.32
2000	12 589	80 860	73.32
2001	13 644	87 635	73.32
2002	14 787	94 977	73.32
2003	16 026	103 276	73.56
2004	17 402	112 144	73.56
2005	18 897	121 773	73.56
2006	20 519	132 229	73.56
2007	22 281	143 582	73.56
2008	24 194	157 156	74.15
2009	26 410	171 554	74.15
2010	28 830	187 270	74.15
2011	31 471	204 427	74.15
2012	34 354	223 155	74.15
2013	37 502	241 986	73.66
2014	40 622	262 121	73.66
2015	44 002	283 931	73.66
2016	47 663	307 557	73.66
2017	51 629	333 148	73.66
2018	55 925	356 769	72.82
2019	60 601	386 595	72.82
2020	65 667	418 915	72.82
2021	71 157	453 937	72.82
2022	77 106	491 887	72.82

7.3.3. Existing Electricity Generation System

The installed electricity generation capacity in 1993, considered as existing capacity in the present study, is 8547 MW. This consists of 2886 MW of hydro, 3528 MW of gas fired, 2051 MW of oil fired, 12 MW of coal fired and a 70 MW nuclear power plant. The actual installed capacity in 1993 was about 9963 MW. The difference in the installed capacities is due to the following reasons: i) the existing capacity reported in the present study is the derated capacity of some of the thermal power plants [20] and the Karachi Nuclear Power Plant, ii) the power plants installed towards the end of the year 1992–93 have not been considered as existing plants because these plants generated electricity only for a few months during the year 1992–93.

7.3.3.1. Hydro power plants

The installed capacity of the hydro power plants in the base year (1992–93) was 2886 MW, comprising Tarbela: 1750 MW, Mangla: 800 MW, Warsak: 240 MW and other small hydro plants: 96 MW. The generation capabilities of these hydro plants undergo large variations during the year due to: i) changes in the hydrological condition of a year, ii) seasonal variations within a year of water inflows to the reservoirs, and iii) seasonal variation of down stream irrigation requirements.

The main hydro power stations in Pakistan, Tarbela and Mangla, have significantly smaller power generation capability in a dry year as compared to that in a normal year. On the other hand, in a wet year, the same plants have substantially more power generation capability. For example in 1982, the average water inflows to Tarbela reservoir were 66 600 ft^3/sec (2352 m^3/sec) as compared to the average inflows in a normal year of 82 600 ft^3/sec (2917 m^3/sec), whereas in 1988 these inflows were 99 200 ft^3/sec (3503 m^3/sec) [20].

The seasonal variation within a year of water inflows to the reservoirs depend upon: a) rainfalls in the upstream catchment areas, and b) temperature variation causing melting of snow in the upstream glacier areas. The Monsoon occurs from July to September in Pakistan, causing heavy rains in north-east areas of the country. During the same period, water inflow in the rivers is also high due to snow melting. These months are thus high water months for inflows to hydro reservoirs. During the rest of the year, rains are scarce and hence October to June are low water months.

The power generation of regulated hydro power stations also depend upon downstream irrigation water demand pattern during the year. There are two main crop seasons namely Rabi (October to March) and Kharif (April to September) and both have their own irrigation water demand patterns. The irrigation water demand patterns for these two seasons are given in Fig. 7.1. It can be seen that minimum irrigation water requirements are in the month of January, while the maximum demand occurs in the month of June.

The available capacity of the main hydro power stations (Tarbela, Mangla and Warsak) during the year for an average hydro condition is shown in Fig. 7.2. The large seasonal variation can be seen from the graph. The available energy from these power plants is about 60% greater in the months of June to November, than in the period of December to May. This variation is not always in line with the electricity peak demand.

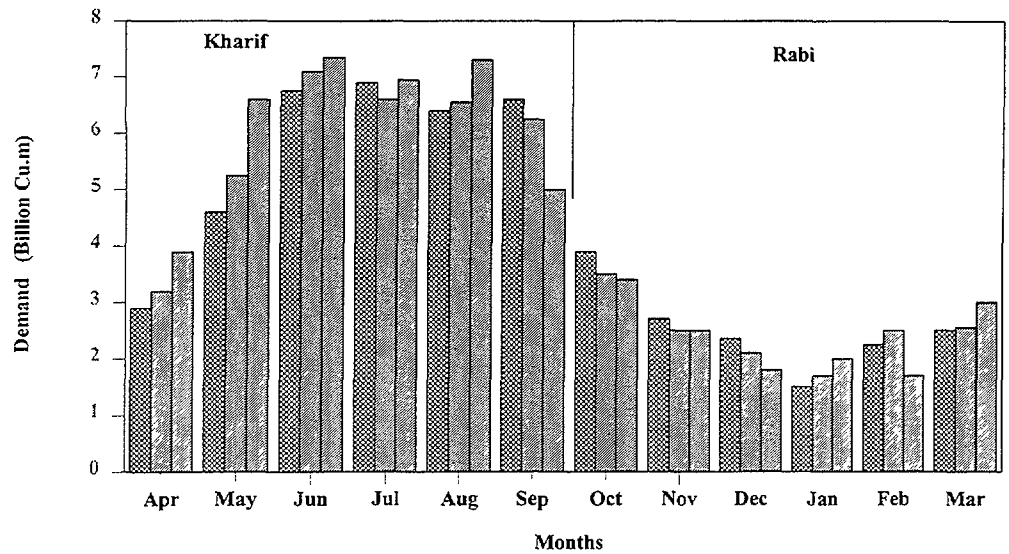


FIG. 7.1. Seasonal Variation in Irrigation Demand

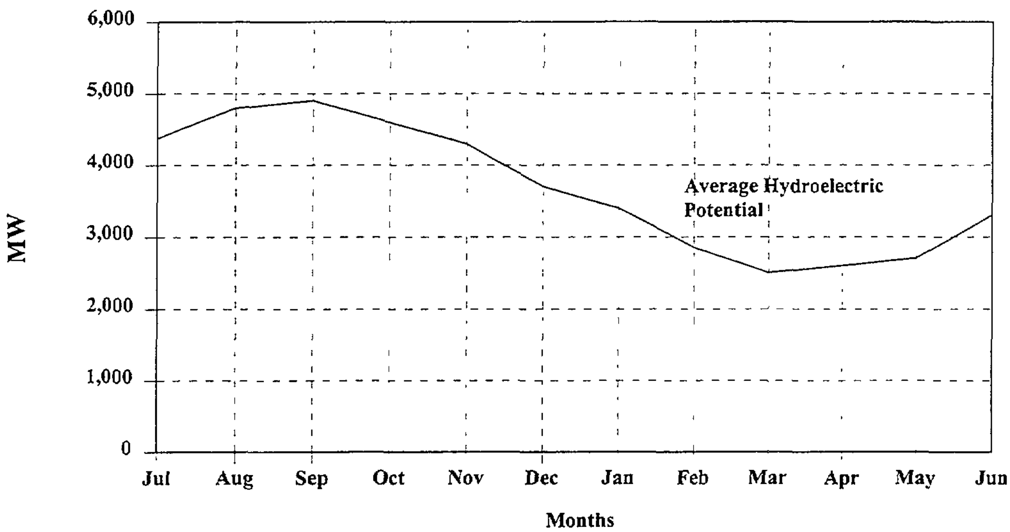


FIG. 7.2. Average Monthly Available Capacity of Main Hydro Power Stations (Tarbela, Mangla, Warsak)

Tarbela

Tarbela is the largest hydro power plant in Pakistan and is the largest earth filled dam in the world. Two companies, TAMS of New York and HARZA Engineering of Chicago, assisted in designing and construction of the project. At the time of its initial filling in 1974, the total storage capacity of the reservoir was 14.3 km^3 of which 11.5 km^3 was live storage. The siltation rate at this dam is significantly high which has reduced the total storage volume to 11.9 km^3 and live storage to 10.4 km^3 [20]. The main purpose of the dam is to regulate water releases for irrigation purposes. There are five tunnels at Tarbela of which three tunnels at present are being used for power generation. At the time of completion in 1977, Tarbela had 4 units (175 MW each) installed with total capacity of 700 MW. Two more extensions to the plant added 6 units of 175 MW each during the period 1982 to 1985. As such, at present, there are 10 units in operation with a total installed capacity of 1750 MW. In the third extension, four more units of 432 MW are presently being added to the plant. Further expansion of power generation capacity is also planned which will be discussed later in the section dealing with candidate hydro power plants. The average monthly inflows to the Tarbela reservoir for the period 1985–1990 are shown in Fig. 7.3. It can be noticed that October to April are low water months while the water inflows are higher in the rest of the year. The average monthly power generation by Tarbela for the last three years (1987 – 1990) is shown in Fig. 7.4. The monthly generation almost follows the same trend as for the irrigation demand shown in Fig. 7.1.

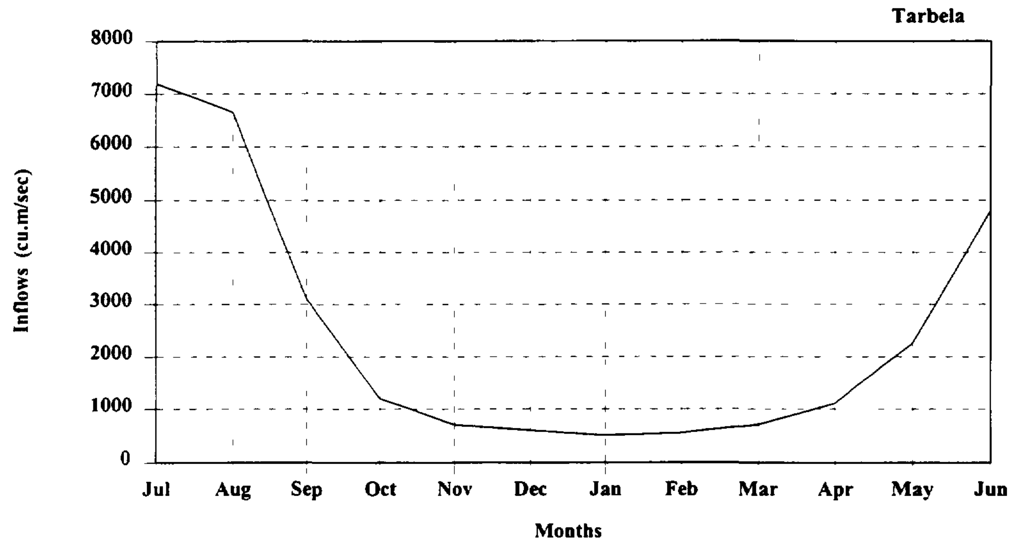


FIG. 7.3. Average Reservoir Inflows (1985–1990)

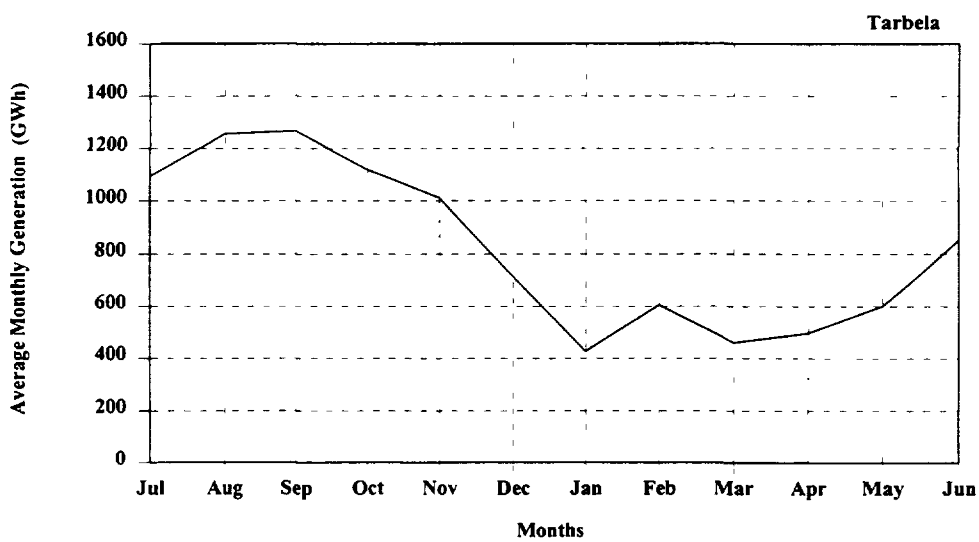


FIG. 7.4. Average Monthly Generation (1987–1990)

Mangla

Mangla dam was built in 1967 on Jhelum river with total storage capacity of 7.6 km^3. The main purpose of this dam is also irrigation. When first completed in 1967, Mangla had four 100 MW units installed with a total capacity of 400 MW. Later on this capacity has been enlarged by adding four more units and now there are 8 units of 100 MW each installed at this dam. Two more units of 100 MW each are presently being installed at the power station. The full supply level of each unit is 107 MW.

Mangla Watershed Management Project was started in 1959–60 with the main objective to reduce sedimentation rate through improved methods of watershed management. However, the siltation problem still exists at Mangla. Due to siltation, the total storage capacity of the dam had reduced from 7.6 km^3 in 1967 to 6.4 km^3 in 1988. The total storage of the dam has been estimated to be 6.0 km^3 in 1993.

The average monthly inflows to the Mangla reservoir for the period 1985–1990 are shown in Fig. 7.5. The variation in water inflows to the reservoir is relatively less than that for Tarbela reservoir. However, on the average, September to February are low water months and March to August are high water months. The average monthly power generation by Mangla for the last three years (1987–1990) is shown in Fig. 7.6. This variation is similar to that for Tarbela power station.

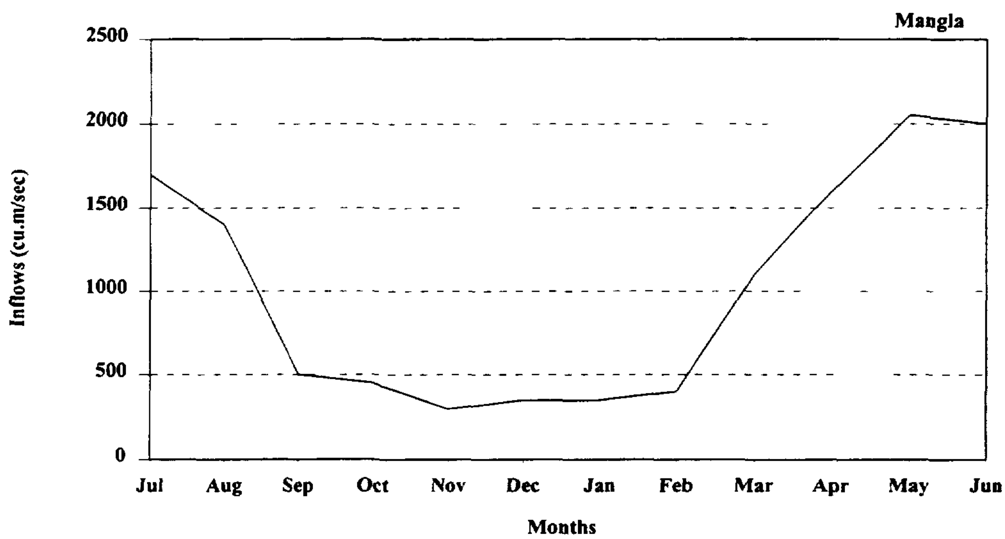


FIG. 7.5. Average Reservoir Inflows (1985–1990)

Warsak

Warsak dam was constructed on Kabul river in 1950. The reservoir has since been completely silted up. It has 6 units of 40 MW each with a total of 240 MW of installed power generation capacity and is being operated as a run-of-river plant. A five year rehabilitation project for the Warsak hydro plant has been initiated so that power station's life and generation capability can be increased. In addition, there are 28 small hydroelectric power plants with total capacity of 96 MW constructed at various canals and barrages.

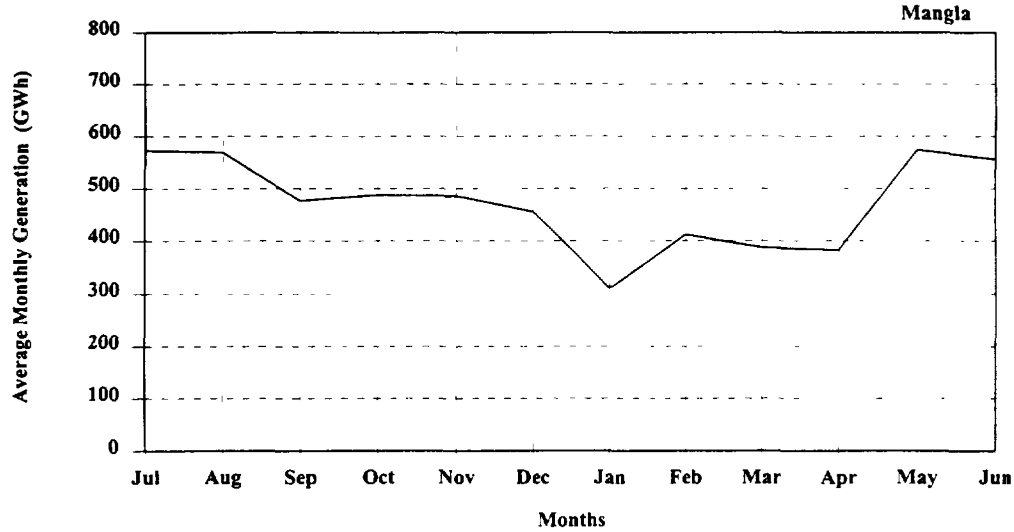


FIG. 7.6. Average Monthly Generation (1987–1990)

Technical Data of Existing Hydroelectric Plants

A large amount of data is available in the country about water inflows and outflows from the dams and the electricity generated from the hydro power plants. Recently WAPDA has conducted a detailed hydro simulation study [20] for the existing and planned hydro projects, using a Reservoir Simulation Model which takes into account the user-specified constraints imposed by hydrology, irrigation requirements, dam design, etc. Based on historical data for the period 1962–1990, three hydro conditions have been specified as dry, average and wet with probabilities of occurrence as 30: 40: 30: respectively. The monthwise available energy, minimum energy and available capacity for existing hydro plants have been worked out in the above mentioned study by WAPDA. For the present study, WAPDA's data, after some adjustments, have been used for WASP input. Table 7.3 gives the period wise data on available energy, minimum energy and available capacity for existing hydro power plants.

Table 7.3. Existing and Committed Hydro Power Plant Data: Groups of Hydroelectric Power Plants

Data item	Group1	Group2
Code name of composite hydro plant	HYD 1	HYD 2
O&M cost of the plant (US$/kW-month)	1.59	1.59

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
WARSAK	WRSK	HYD2	240	10

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	339	327	238	337	325	235	338	253	235
2	119	107	237	233	221	235	149	112	237
3	100	88	197	128	116	197	80	59	197
4	90	78	197	112	100	197	87	66	197
5	133	121	237	226	214	230	231	173	234
6	332	320	233	325	313	231	332	249	231

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
TARBELA 1–10	TA10	HYD1	1750	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1721	1720	1179	2420	2418	1658	2886	2885	1977
2	1604	1522	1966	2392	2290	1973	2378	2276	1977
3	1941	1810	1796	2034	1923	1796	2014	1898	1796
4	897	834	1428	1322	1228	1428	1337	1258	1428
5	979	927	836	1027	987	836	1112	1088	836
6	600	599	588	951	950	657	1315	1314	901

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
MANGLA 1–8	MA08	HYD2	800	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	498	329	919	1083	1030	920	1343	1340	920
2	463	368	920	953	874	920	1133	1091	920
3	771	659	911	777	673	890	826	731	891
4	449	382	768	688	605	756	799	742	800
5	502	435	575	858	835	669	1142	1136	804
6	365	284	753	1098	1071	845	1312	1310	899

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
SMALL HYDRO	SMHY	HYD2	96	0

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	54.6	54.4	47.4	64.6	64.4	56	76.2	76	66.1
2	39.4	39.2	27.1	46.6	46.4	32	55	54.8	37.8
3	39.4	39.2	27.1	46.6	46.4	32	55	54.8	37.8
4	39.4	39.2	27.1	46.6	46.4	32	55	54.8	37.8
5	39.4	39.2	27.1	46.6	46.4	32	55	54.8	37.8
6	69.6	69.4	48	82.2	82	57	97	96.8	67

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
TARBELA 1–10 RETIRED	TA10	HYD1	–1750	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1721	1720	1179	2420	2418	1658	2886	2885	1977
2	1604	1522	1966	2392	2290	1973	2378	2276	1977
3	1941	1810	1796	2034	1923	1796	2014	1898	1796
4	897	834	1428	1322	1228	1428	1337	1258	1428
5	979	927	836	1027	987	836	1112	1088	836
6	600	599	588	951	950	657	1315	1314	901

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
TARBELA 1–14	TA14	HYD1	3478	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	3811	0	3584	4852	0	3401	5033	0	3597
2	3309	0	3563	3664	0	3563	2966	0	3623
3	1430	0	2533	1462	0	2533	1473	0	3199
4	892	0	1939	916	0	1946	1282	0	2607
5	672	0	1390	806	0	1429	819	0	2205
6	1816	0	1624	1893	0	1529	3770	0	3121

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
MANGLA 1–8	MA08	HYD2	–800	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	498	329	919	1083	1030	920	1343	1340	920
2	463	368	920	953	874	920	1133	1091	920
3	771	659	911	777	673	890	826	731	891
4	449	382	768	688	605	756	799	742	800
5	502	435	575	858	835	669	1142	1136	804
6	365	284	753	1098	1071	845	1312	1310	899

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
MANGLA 1–10	MA10	HYD2	1070	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1199	400	1070	1405	400	1092	1580	400	1092
2	1320	400	1070	1268	400	1070	1069	400	1070
3	678	400	934	815	400	1070	789	400	1070
4	126	124	384	415	364	671	528	400	747
5	737	400	851	896	400	806	798	400	898
6	1381	400	1067	1318	400	1061	1302	400	1070

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
CHASHMA	CHMA	HYD2	184	0

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	219	217	157	220	218	159	199	197	155
2	191	189	148	180	178	130	214	212	179
3	131	129	98	128	126	94	196	194	150
4	124	122	95	138	136	96	150	148	110
5	148	146	132	181	179	152	184	182	155
6	245	243	180	251	249	181	246	244	184

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
GHAZI BROTHA	GHZ3	HYD2	1450	600

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1534	1194	1450	1510	1170	1428	1462	1122	1387
2	1500	1160	1450	1517	1177	1450	1176	836	1450
3	1100	760	1450	1123	783	1450	854	514	1450
4	844	504	1160	869	529	1160	988	648	1160
5	679	339	1450	936	596	1450	621	281	1450
6	1481	1141	1450	1497	1157	1450	1485	1145	1450

Table 7.3. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
TARBELA 1–14	TA14	HYD1	–3478	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	3811	0	3584	4852	0	3401	5033	0	3597
2	3309	0	3563	3664	0	3563	2966	0	3623
3	1430	0	2533	1462	0	2533	1473	0	3199
4	892	0	1939	916	0	1946	1282	0	2607
5	672	0	1390	806	0	1429	819	0	2205
6	1816	0	1624	1893	0	1529	3770	0	3121

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)
TARBELA with KALABAGH	TB02	HYD1	3478	10 000

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	4109	0	3549	4852	0	3401	5033	0	3597
2	3309	0	3563	3664	0	3563	3437	0	3728
3	1454	0	2533	1491	0	2533	1300	0	3199
4	637	0	2125	650	0	2056	1176	0	2854
5	473	0	2093	782	0	1928	892	0	2761
6	2775	0	2621	2925	0	2485	4513	0	3188

Various problems have been encountered during the preparation of input data for the hydro power plants. One of the problems experienced with hydro plant representation in WASP is that if additional units are added to an existing plant, some times the minimum and maximum hydro generation capabilities get changed. This problem has been solved by retiring the existing hydro power plant and introducing a committed hydro plant with increased capacity and modified seasonal energy data. A more difficult part of this type of problem arises when additional units to be added to an existing hydro plant are considered as candidate hydro power plants. As a result of this addition, sometimes the WASP input parameters for the overall hydro power plant are modified. In this case, it is not known in which year this additional hydro plant will be added to the system by the model and it is not possible to retire the existing hydro plant and add a modified plant. To simulate, such a type of hydro plant addition in VARSYS, the additional units to be added were first represented in the VARSYS as independent units to determine their year of acceptance and then the existing plant was retired in that year and a new hydro plant with modified energy and capacity data was included in the VARSYS module with pre-determined year of availability.

WASP does not take into account the scheduled maintenance and forced outages of the hydroelectric power plants so these parameters for the respective hydro plants should be properly incorporated externally while preparing the energy data for these plants. For the existing hydroelectric plants in the system, it was assumed that maintenance of the units would occur in low flow period resulting in no loss of energy. However, there would be a reduction in peaking capacity for some plants which was reflected in the energy data of the respective plants.

The normal scheduled maintenance requirements for the existing hydro plants are:

Mangla (units 1–8) 15 days/unit/year

Tarbela (units 1–10) 20 days/unit/year

Warsak (units 1–8) 30 days/unit/year

The same maintenance requirements were used for additional units at Mangla and Tarbela. For the new committed and candidate plants this value has been taken as 20 days/unit/year.

The forced outage rates for the hydro plants are much lower than that for the thermal plants. The typical value for the hydro plants is about 2% or less. It may cause some loss of energy in high flow period only, which in Pakistan occurs only for about 3–6 months, therefore the effect of forced outages of hydro plants has been neglected.

7.3.3.2. Thermal power plants

Thermal power plants are important part of the country's power system, which are required to meet the increasing demand. Although hydroelectric power is the cheapest source of energy and it can be developed at several suitable sites, many difficulties arise in its development due to seasonal variations in the availability of water and remoteness of their location with respect to the grid. Thus, the development of thermal power plants was planned to complement hydro generation and to meet the demand of electricity, particularly during the low water months. Unlike hydro power stations, these can provide continuous supply of electricity throughout the year. Recently, WAPDA has installed high efficiency combined cycle plants in which waste gases released from gas turbines are used to raise steam and no additional fuel is needed. The adoption of new combined cycle technology has economised the use of fossil fuels in these plants. The thermal power plants already developed are contributing about two-thirds of the total existing capability. A number of thermal units are currently under installation for meeting rapidly increasing demand in the future.

The installed capacity of existing fossil fuels based thermal power plants in the base year (1992–93) was 5661 MW consisting of 3239 MW of steam units, 960 MW of combustion turbines and about 1392 MW of combined cycle power plants. About half of this capacity is based on oil while the other half is based on gas or consists of dual fuel fired power plants which are basically gas fired but in the winter months, when gas demand in the domestic sector is high, these plants are switched to furnace oil or HSD. In WASP, it is difficult to represent such type of dual fuel power plants. For the present study, these plants are assumed to be based on the fuel which dominates in the generation of that particular plant.

The major thermal power stations covering about 70% of the thermal capacity are Guddu, Kot Addu, Bin Qasim, Jamshoro, Muzaffargarh and Korangi.

Guddu is the largest thermal power station in the system. It is a combined cycle plant consisting of 640 MW (2x110 MW, 2x210 MW) steam turbines commissioned in the period 1974–1986 and 1015 MW (4x100 MW gas turbines along with 2x100 MW of bottoming cycle units and 2x135 of gas turbines with 1x145 MW of bottoming cycle units) developed in the period 1985–1993. As the plant is located in the vicinity of gas fields, natural gas is the fuel used in this power plant. The oldest two steam units of the plant have been partially rehabilitated.

Kot Addu Power Station consists of 1000 MW of combustion turbines out of which 600 MW have been converted to combined cycle system by adding 324 MW of bottoming cycle units. The combustion turbines were initially operated on a blend of Furnace oil and HSD but due to higher outages rate, HSD is now being used. Supply of natural gas is being planned to avoid higher cost of HSD. Thus with the availability of natural gas, both the fuels, i.e. gas and HSD will be used. The higher use of gas will considerably improve the plant performance. As a result, with the increasing use of gas, the HSD requirements will be reduced and pollutant emissions will also decrease.

The Bin Qasim Power Station has 5 steam units of 210 MW each which are furnace oil fired. Jamshoro Power Station consists of one unit of 250 MW and three units of 210 MW each and all these are steam plants. Of these the 250 MW unit operates on furnace oil while the 3x210 MW units operate on natural gas, when available, and operate on furnace oil when there is shortage of gas supply.

Korangi thermal power station has two 125 MW and two 66 MW steam units commissioned in the period 1965 to 1977. This is a dual fuel plant which uses both furnace oil and natural gas as fuel.

Apart from these major power stations there are smaller units of various capacities ranging from 3–66 MW based on furnace oil and natural gas while one steam unit (1x15 MW) based on domestic coal are also present in the system.

Table. 7.4. Characteristics of Existing, Under Construction and Firmly Committed Thermal Power Plants

Name	No of Units	Minimum Operating Level (MW)	Maximum Capacity (MW)	Heat rate (kcal/kW h)		Fuel cost (cent/10^6 kcal)		Fuel Type	Spinning Reserves (%)	Forced Outage Rate (%)	Scheduled Maintenance (days/year)	Maintenance Class (MW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)
				Minimum	Avg Incr	Domestic	Foreign							
MULT	4	15	59	3748	3212	1223	0	Dom Gas	11	7	30	60	1 33	1 7
FDST	2	15	58	3673	3148	1223	0	Dom Gas	11	7	30	60	1 33	1 7
GU12	2	25	98	3124	2677	1223	0	Dom Gas	11	7	30	100	1 33	1 7
GU34	2	47	188	3124	2677	1223	0	Dom Gas	11	7	30	200	1 33	1 7
STM1	1	12	52	5537	4766	1223	0	Dom Gas	11	10	30	50	1 33	1 7
QTST	2	2	6	4950	4242	1020	0	Dom Coal	11	7	30	10	4 17	4
GUCC	2	146	291	2715	1812	1223	0	Dom Gas	11	12	30	300	58	3
KACC	2	142	283	2715	1812	1223	0	Dom Gas	11	12	30	300	58	3
FDCC	1	61	122	3574	2386	1223	0	Dom Gas	11	12	30	150	58	3
KOCC	1	61	122	3574	2386	1223	0	Dom Gas	11	12	30	150	58	3
JOF1	1	60	241	2547	2183	0	1199	HSFO	11	7	30	250	1 33	1 7
JOF2	3	50	200	2547	2183	0	1199	HSFO	11	17	30	200	1 33	1 7
MUZ1	0	53	210	2547	2183	0	1199	HSFO	11	12	30	250	1 33	1 7
GTG1	1	260	260	3932	3932	1223	0	Dom Gas	0	10	20	300	1	4 2
GTG2	1	160	160	4833	4833	1223	0	HSD	0	10	20	200	1	4 2
KTP2	2	30	118	4862	4166	1223	0	Dom Gas	11	7	30	150	1 33	1 7
BQSM	5	53	210	2905	2490	0	1199	HSFO	11	8	30	250	1 33	1 7
LFBC	0	13	50	3038	2629	1020	0	Dom Coal	11	12	42	50	3 8	4
KTP1	2	16	62	4862	4166	1223	0	Dom Gas	20	7	30	100	1 33	1 7
KAC2	0	184	283	3359	2241	1223	0	Dom Gas	11	12	30	400	58	3
KAGT	6	45	90	3907	2601	1223	0	Dom Gas	20	10	30	100	1 0	4 2
KAC3	0	150	300	3359	2241	1223	0	Dom Gas	11	12	30	300	58	3
GCC2	0	202	404	2792	1864	1223	0	Dom Gas	11	12	30	400	58	3
MUZ2	0	80	320	2547	2183	0	1199	HSFO	11	17	30	300	1 33	1 7
CHNU	0	160	325	2707	2433	275 4	0	Nuclear	11	9	42	350	3 37	7
HUB	0	81	323	2827	2423	0	1199	HSFO	11	7	30	350	1 33	1 7
JOF3	0	88	350	2547	2183	0	1199	HSFO	11	17	30	350	1 33	1 7
KANP	1	70	70	2838	2838	205	0	Nuclear	0	22	45	100	1	2 5

In addition, a 137 MW CANDU type nuclear power plant, with a derated capacity of 70 MW i.e. Karachi Nuclear Power Plant (KANUPP), also exists in the system. This plant was built at Karachi in 1971 by Canadian General Electric. The plant has been performing satisfactorily despite some difficulties in the supply of fuel and spare parts from the supplier. It is now being refurbished to extend its life and enhance the safety aspects. Due to limited supply of indigenous fuel and spares, the plant is generally operated at a lower capacity. For the present analysis its capacity has been assumed as 70 MW.

Technical Data of Existing Thermal Plants

The power system statistics published by the utilities annually do not report directly the technical data required for the WASP model. Information is available on total generation and total fuel used by each plant annually. This information is insufficient to calculate the heat rates for minimum load and the average incremental loads. Some inconsistencies have also been noted in some of the WASP input parameters related to thermal power plants prepared by WAPDA for its National Power Plan study [20]. The data reported for the heat rates (at minimum operating level and at full load) for some of the old thermal power plants show them to be more efficient than similar new thermal power plants. Due to these problems data on heat rates for some of the thermal power plants have been modified in line with the plants with similar size and age. Similarly forced outage rate, scheduled maintenance and spinning reserves for some of the existing power plants have been adjusted in the light of previous operations record of these power plants and that for similar power plants in the system. The maximum unit generating capacity of these plants are based on the derated capacities due to the ageing factor and the difference of ambient parameters between the site and the ISO specifications. The technical and economic characteristics of existing thermal power plants are given in Table 7.4

In order to keep the number of power plants within a manageable range, some of the smaller steam plants with almost same capacities have been combined to be represented as a single plant in the present data set. Their data, e.g. the heat rates, forced outage rate and O&M costs, have been accordingly averaged out weighted by their installed capacities. Some smaller gas turbines units have also been combined in a similar way to be represented as a single unit of their combined capacity.

7.3.4. Committed Power Generation Capacity

The projects considered as committed in the present study are discussed below. These projects are either under construction or have firm construction schedule with financial arrangements finalised.

7.3.4.1. Hydro power plants

Two new hydro power projects namely Ghazi Brotha and Chashma and two extensions of Tarbela and Mangla hydroelectric plants are considered as committed power plants. The Ghazi Brotha hydel power plant will be located at about 7 km downstream of Tarbela with a limited peaking capability. The plant will consist of 5 units of 290 MW each with a total capacity of 1450 MW. The average annual energy output is estimated at about 7000 GW·h and the project is expected to be commissioned in 2002.

The other committed hydro power project is Chashma hydroelectric plant. Its feasibility report was prepared in 1987. It will have eight 23 MW units with a total capacity of 184 MW.

The average annual energy generated will be 1080 GW·h and it is expected that the plant will be commissioned in 1997. Four more units of 432 MW each are presently being installed at Tarbela power station which will result in a total installed capacity of 3478 MW at this power station. Similarly, two more units of 100 MW capacity each are also being added to Mangla hydro power plant resulting in total capacity of 1000 MW. Both of these extensions have been considered as committed hydro plants in the present study. Table 7.3 gives the WASP input data for committed hydro power plants.

7.3.4.2. Thermal power plants

The committed thermal power plants include a 4x323 MW furnace oil fired steam plant now under construction by the private sector at Hub and additional oil fired steam units at some of the existing power stations e.g. Muzaffargarh: (5x210 MW, 1x320 MW), Bin Qasim: (210 MW) and Jamshoro: (1x350 MW), with a total capacity of about 3200 MW. The existing 4x25 MW gas turbine units at Faisalabad and Kotri will be converted to combined cycle units by adding bottoming cycle units of 40 MW each. The capacity of combined cycle units at each of these stations will thus become 140 MW. Three 50 MW coal fired fluidized bed combustion turbines are under construction at Khanot, which will use domestic coal as fuel.

A PWR type nuclear power plant of 325 MW generation capacity is also under construction at Chashma. The plant is being constructed with the help of Chinese National Nuclear Corporation and will start commercial operation by the year 1999.

The technical and economic data of the committed thermal power plants used for the WASP based analysis are given in Table 7.4.

7.3.5. Future Electricity Supply Options

The future electricity generation mix of the country will be governed mainly by the supply potential of the indigenous energy resources. As discussed in Chapter 2, the total proven fossil fuel reserves amount to only 916 million TOE (or 7 TOE per capita) comprising: Gas: 408 million TOE, Oil: 27 million TOE and Coal: 481 million TOE [14]. Recently a large coal resource has been identified at Thar, Sind, with estimated hypothetical resource potential of over 100 billion tons. The field still remains to be investigated in detail for its reserves estimates, mineability and quality of coal.

Future availability of indigenous fossil fuels for power generation will remain very limited. Natural gas which at present supports about 30% of the power generation capacity is already in short supply. Additional commitments of gas supply for power generation can only be made if some new large gas fields are discovered. The proven coal reserves can hardly support 1,000 MW power generation capacity. However, it is hoped that the recently discovered large coal field at Thar may be developed in the next 10–15 years to supply coal for 10 000–15 000 MW power generation capacity.

Although, Pakistan is endowed with large hydro power potential (some 30 000 MW) [20], only 15% of this potential has been exploited so far. Future development of hydro power is, however, constrained by a combination of techno-economic, environmental and socio-political factors. At present, 1630 MW hydro capacity (Ghazi Brotha and Chashma) is under construction while about 1960 MW (extension of Tarbela and Kohala) is being planned. In addition, construction of two large hydro projects (Kalabagh: 2400 MW; Basha: 3360 MW) with a total installed capacity of about 6000 MW is also under consideration.

The first nuclear power plant, a 137 MW (gross capacity) CANDU type plant, was built in Pakistan in 1971. The plant has performed satisfactorily over the last 23 years (despite some difficulties in supply of fuel and spares from the supplier) and is now under refurbishment to extend the life and enhance safety aspects. The second nuclear power plant, a 325 MW PWR unit, is under construction at Chashma site. It is envisaged that nuclear power generation would be able to play a relatively more significant role in the coming decades.

Apart from large hydro, the only significant contribution by renewable energy sources in power generation has been from mini/ micro hydroelectric plants. At present there are over 100 such plants with a total capacity of 1230 kW in operation. New sites have been identified for construction of 500 MW additional capacity based on mini/ micro hydel plants. So far only 2 wind electricity generators of 20 kW each and 18 PV stations of total capacity 434 kWp have been built, essentially for demonstration purposes [14].

In view of the limitations of indigenous energy resources, import of coal and natural gas is being planned. As discussed in Chapter 6, at present, three pipelines for gas import with capacity of 1–2 billion ft^3/day (35–71 million m^3/day each) from Iran, Qatar/ Oman and Turkmenistan are under consideration [10]. It is expected that one of these pipelines will be operational soon after the turn of the century. It is envisaged that a sizeable fraction of the imported gas will be available for power generation. As for use of imported coal for power generation, this will be an economical proposition only if the corresponding power generation capacity is located near the coast line. Still, it would need considerable expansion of existing port handling facilities in the country.

Keeping in view the above, the following candidate plants have been considered for future electric system expansion:

1) 300 MW Oil fired steam units
2) 600 MW Oil fired steam units
3) 600 MW Coal fired steam units (without FGD)
4) 600 MW Coal fired steam units (with FGD systems)
5) 100 MW Coal fired FBC units
6) 450 MW Gas fired combined cycle units
7) 100 MW Gas fired combustion turbine units
8) 600 MW Nuclear power plants

The technical and economic data for all the candidate thermal power plants are given in Table 7.5.

As for hydro candidates, two large hydro projects, Kalabagh (2400 MW) and Basha (3360 MW), one medium sized hydro plant, Kohala (1000 MW), and two small hydro plants, Jinnah (144 MW) and Taunsa (120 MW) have been considered as candidate plants. In addition, an extension of Tarbela (960 MW) hydro project is also considered as a hydro candidate. Table 7.6 gives WASP input data for candidate hydro power plants.

Table 7.5. Characteristics of Candidate Thermal Power Plants

Name	Minimum Operating Level (MW)	Maximum Capacity (MW)	Heat rate (kcal/kW h)		Fuel cost (cent/10^{6} kcal)		Fuel Type	Spinning Reserves (%)	Forced Outage Rate (%)	Scheduled Maintenance (days/year)	Maintenance Class (MW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)
			Min	Average Incremental	Domestic	Foreign							
FOL3	75	300	2827	2423	0	1199	HSFO	11	7	28	300	1 33	1 7
FOL6	150	600	2827	2423	0	1199	HSFO	11	7	28	600	1 33	1 7
COAL	150	600	2852	2444	0	902	Imp Coal	11	10	42	600	1 25	2 1
WFGD	150	600	2908	2493	0	902	Imp Coal	11	12	42	600	1 7	2 5
DCOL	25	100	3067	2565	1020	0	Dom Coal	11	13	42	100	3	4
CCIG	225	450	2493	1664	0	1223	Imp Gas	11	12	28	450	58	3
GTIG	100	100	3151	3151	0	1223	Imp Gas	0	10	21	100	1	4 2
NUCL	300	600	2603	2340	0	194 2	Nuclear	7	10	42	600	2 5	5

Table 7.6. Candidate Hydro Power Plants Data
Groups of Hydroelectric Power Plants

Data item	Group1	Group2
Code name of composite hydro plant	HYD 1	HYD 2
O&M cost of the plant (units)	1.59	1.59

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Jinnah	JINH	HYD2	144	0	2003

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	186	184	129	186	184	129	186	184	129
2	152	150	143	152	150	143	152	150	143
3	113	111	87	113	111	87	113	111	87
4	96	94	74	96	94	74	96	94	74
5	119	117	85	119	117	85	119	117	85
6	202	200	142	202	200	142	202	200	142

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Taunsa	TAUN	HYD 2	120	0	2005

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	128	126	88	164	162	113	166	164	114
2	130	128	90	158	156	109	158	156	109
3	72	70	50	82	80	57	76	74	53
4	44	42	31	60	58	42	64	62	44
5	72	70	50	106	104	73	136	134	94
6	146	144	101	162	160	111	148	146	102

Table 7.6. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Kalabagh 1	KBG1	HYD 1	1200	10 000	2006

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1100	0	1345	1685	0	1374	1847	0	1364
2	846	0	1353	877	0	1349	803	0	1388
3	387	0	1187	384	0	1177	399	0	1388
4	313	0	949	294	0	916	354	0	1157
5	249	0	760	320	0	762	374	0	1371
6	650	0	683	671	0	755	950	0	809

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Kalabagh 2	KBG2	HYD 1	1200	10 000	2007

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1100	0	1345	1685	0	1374	1847	0	1364
2	846	0	1353	877	0	1349	803	0	1388
3	387	0	1187	384	0	1177	399	0	1388
4	313	0	949	294	0	916	354	0	1157
5	249	0	760	320	0	762	374	0	1371
6	650	0	683	671	0	755	950	0	809

Table 7.6. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Kohala	KOHA	HYD 2	1000	0	2008

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	1358	1356	1014	1436	1434	1149	1589	1587	1144
2	415	413	330	654	652	592	743	741	540
3	392	390	273	274	272	195	245	243	169
4	211	209	158	435	433	377	358	356	274
5	1201	1199	1078	1387	1385	1105	1550	1548	1137
6	1666	1664	1175	1686	1684	1175	1557	1555	1156

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity(GW·h)	First year this plant can be added to the system
Tarbela 15–16	TA16	HYD 1	4438	10 000	2009

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	4720	0	4371	5790	0	4439	6321	0	4525
2	3313	0	4483	3892	0	4483	3503	0	4667
3	1454	0	3258	1490	0	3258	1300	0	4116
4	637	0	2733	650	0	2645	1176	0	3672
5	473	0	2693	782	0	2481	892	0	3553
6	3066	0	3297	3121	0	3446	5042	0	4011

Table 7.6. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)	First year this plant can be added to the system
Basha 1	BSH1	HYD 1	840	10 000	2011

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	764	0	764	1241	0	856	1248	0	856
2	835	0	796	850	0	798	861	0	840
3	181	0	531	245	0	613	326	0	840
4	158	0	465	208	0	571	207	0	675
5	156	0	426	270	0	459	212	0	682
6	687	0	638	821	0	799	1055	0	840

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)	First year this plant can be added to the system
Basha 2	BSH2	HYD 1	840	10 000	2012

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC
1	764	0	764	1241	0	856	1248	0	856
2	835	0	796	850	0	798	861	0	840
3	181	0	531	245	0	613	326	0	840
4	158	0	465	208	0	571	207	0	675
5	156	0	426	270	0	459	212	0	682
6	687	0	638	821	0	799	1055	0	840

Table 7.6. (Contd.)

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)	First year this plant can be added to the system
Basha 3	BSH3	HYD 1	840	10 000	2013

Period	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
1	764	0	764	1241	0	856	1248	0	856
2	835	0	796	850	0	798	861	0	840
3	181	0	531	245	0	613	326	0	840
4	158	0	465	208	0	571	207	0	675
5	156	0	426	270	0	459	212	0	682
6	687	0	638	821	0	799	1055	0	840

Project Name	Code Name	Hydro Group	Installed Capacity(MW)	Energy Storage Capacity (GW·h)	First year this plant can be added to the system
Basha 4	BSH4	HYD 1	840	10 000	2014

	Hydrocondition 1			Hydrocondition 2			Hydrocondition 3		
Period	EA	EMIN	HMWC	EA	EMIN	HMWC	EA	EMIN	HMWC
1	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)	EA (GW·h)	EMIN (GW·h)	HMWC (MW)
2	835	0	796	850	0	798	861	0	840
3	181	0	531	245	0	613	326	0	840
4	158	0	465	208	0	571	207	0	675
5	156	0	426	270	0	459	212	0	682
6	687	0	638	821	0	799	1055	0	840

7.4. Operating Practices for the Power Plants Considered

A large number of power plants (more than 300 units) will be present in the system towards the end of planning horizon. Simulation of the operation of such a large number of power plants on unit by unit bases is not possible due to a limitation in the WASP programme on the maximum number of capacity blocks that can be handled by the program. However, the program allows plant by plant loading option. The use of this option for loading the plants results in significantly different load allocation to various plants as compared to the case when the unit by unit loading option is used. This limitation of the model has been overcome by:

- decreasing the number of existing plants by representing the plants in closer range of capacities as a single plant with multiple units and grouping small power plants into a single plant as described in section 7.3.3.2.
- introducing a new oil fired plant with 600 MW capacity in the system after the year 2011 in order to reduce the number of plants.

Maintenance Practices

Scheduled maintenance of generating equipment plays a vital part in retaining a unit's efficiency, reducing forced outages and preserving its useful life. When the overall generating system is unable to fully meet the demand, there is a temptation to delay maintenance of the plant until the situation improves. However, this situation will often result in increased forced outage of the plants. The present practice in Pakistan is to perform annual maintenance of hydro plants in low water months and that of thermal plants in the high water months. This situation is roughly represented in the maintenance schedule worked out by WASP.

7.5. Major Physical Constraints

7.5.1. Hydro Power Development

Development of hydro power capacity is limited by the number of sites available in the country for installation of such power plants. Longer lead times are required for feasibility studies for site evaluation and technical design studies. Further, due to huge manpower requirements as well as substantial financial resources involved in large hydro power projects, only a limited number of hydro power plants can be constructed simultaneously in developing countries like Pakistan.

In view of the above considerations, the following schedule for future development of hydroelectric projects has been assumed for the present study. The larger hydro power plants like Kalabagh and Basha have been assumed to be developed in two and four stages respectively. Kalabagh-1 (1200 MW) is assumed to be commissioned earliest by the year 2006 while the year of availability for another 1200 MW of the same project has been assumed as 2007. Four stages of Basha project, 840 MW each, have been assumed to be available for commissioning in consecutive years starting from the year 2011. The other two candidate hydro power plants of Kohala (1000 MW) and Tarbela (960 MW) are expected to be available by the year 2008 and 2009 respectively.

7.5.2. Indigenous Fuel Sources

Among the indigenous sources available for electricity generation, the only relatively abundant source is coal. The coal fired power capacity based on domestic coal can only be installed at the mine mouth, due to the problems of transportation. At one of the coal fields, Lakhra, where some power capacity has already been planned, the maximum proven reserves are limited and can provide fuel to a power capacity of about 1000 MW. The recently discovered Thar coal field is being investigated for its resource potential, quality of coal and mineability. As long lead time is required to develop this coal field thus it has been assumed that this coal field may replace about 10 000–15 000 MW of imported coal fired plants.

As for the supply of gas for power generation, due to the shortage of natural gas in the country and its increasing demand in other sectors, it is expected that additional gas supply for power sector will not be available from indigenous sources except from the gas fields not yet utilised and having gas of low calorific value. In the case of indigenous oil, the present production can only support about 20% of the total oil requirements in the country and this share is not expected to increase substantially in the planning horizon. As such, all future oil fired power plants are assumed to be based on imported oil.

7.5.3. Nuclear Power Development

Nuclear power development requires high initial investments, huge industrial infrastructure and skilled manpower for its development. Besides, site evaluation and technical design studies take much longer lead time for nuclear power plants compared to fossil fuel based power plants. As such, only a gradual nuclear power development programme can be considered for the next few decades. For the present study it has been assumed that the construction of a first 600 MW nuclear power plant can be started in 1996 and the plant will become operational in the year 2002. Further, it has been assumed that the next two plants could be available for commissioning in 2005 and 2007 respectively. After that one plant has been assumed to be available each year till the year 2018. Starting from the year 2019, it has been assumed that two nuclear power plants could be commissioned each year.

7.5.4. Fuel Transportation and Siting of Power Plants

The transport system of Pakistan is already heavily loaded. As such, before construction of a power plant, it should be assured that sufficient supplies of the fuel would be available for the whole life of that particular power plant. Large quantities of coal are required for a coal fired power plant and it is not feasible to transport such quantities through the available roads and rail networks because both of them are heavily loaded. Thus, it has been assumed for the present study that all the imported coal fired capacity will be installed at the coastal areas. In the case of indigenous coal based power plants in view of transportation difficulties it has been assumed that these plants will be located near the coal fields.

As far as the transportation of oil is concerned, it is not feasible to transport large quantities of oil for power production through roads. In the present study, it has been assumed that imported oil based power plants could be installed at the coast as well as up to mid country areas. The required quantities of oil to the mid country sites of these plants will be transported through rail or pipelines.

Siting of power plants have not been analysed in detail for the present study. However, it is generally known that only those sites where sufficient supplies of cooling water are available for the whole life of the power plant can be considered for power projects, besides other considerations such as vicinity of load centres, transmission, accessibility of site.

7.6. System Reliability Constraints

The present installed capacity is inadequate to meet the peak demand due to seasonal variation of hydro generation capability. The reserve margin of the system is, thus, at present negative. However, such a situation can not be allowed to continue in future. The government is planning to eliminate power shortages by the year 1998 by adding new power plants in both public sector as well as in the private sector.

In the present study, the minimum reserves margin in the critical period of a year (the period when the difference between peak load and the available capacity is minimum) has been increased from the present negative value of –4% to a level of 15% in the year 2004 and has been kept constant for the remaining study period. Since, the system has a significant share of hydro, no loss of load probability (LOLP) limit has explicitly been imposed. In such a situation, energy not served (ENS) is more important and an appropriate value for penalizing the system should be used. However, the LOLP of the system resulting from the optimum solution is assessed to remain within acceptable range (equivalent to 1–2 days/year). The data for configuration generation and that for system simulation are reported in Table 7.7 and Table 7.8 respectively.

Table 7.7. Constraints for the Generation of Expansion Configuration

Year	Permissible reserves margin (%)	
	minimum	maximum
1993	–4	20
1997	5	20
1998	10	20
1999	10	25
2000	11	25
2001	12	25
2002	13	25
2003	14	25
2004	15	25

Table 7.7. (Contd.)
Data for Configuration Generation

Range of units of each expansion candidate that can be expected each year											
YEAR		FOL3	FOL6	COAL	WFGD	DCOL	CCIG	GTIG	NUCL	HYD1	HYD2
1993	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1994	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1995	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1996	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1997	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1998	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	0	0	0	0	0
1999	MIN	0	0	0	0	0	0	0	0	0	0
	INCR	0	0	0	0	0	1	0	0	0	0
2000	MIN	0	0	0	0	1	0	0	0	0	0
	INCR	0	0	1	0	0	2	2	0	0	0
2001	MIN	0	0	0	0	2	2	0	0	0	0
	INCR	0	0	2	0	0	0	2	0	0	0
2002	MIN	0	0	0	0	3	2	0	0	0	0
	INCR	0	0	2	0	0	3	3	1	0	0
2003	MIN	0	0	0	0	4	3	0	0	0	0
	INCR	0	0	2	0	0	3	4	1	0	1
2004	MIN	0	0	0	0	5	5	0	0	0	0
	INCR	0	0	3	0	5	3	5	1	0	1
2005	MIN	0	0	1	0	6	7	0	1	0	0
	INCR	0	0	2	0	6	3	6	1	0	2
2006	MIN	0	0	1	0	7	9	2	1	0	1
	INCR	0	0	3	0	0	3	4	1	1	1
2007	MIN	0	0	1	0	8	9	2	2	0	2
	INCR	0	0	3	0	0	4	5	1	2	0
2008	MIN	0	0	1	0	9	9	3	3	1	2
	INCR	0	0	3	0	0	4	5	1	1	1
2009	MIN	0	0	1	0	10	11	6	4	1	3
	INCR	0	1	3	0	0	4	4	1	2	0
2010	MIN	0	0	1	0	10	14	7	5	3	3
	INCR	0	2	3	0	0	3	4	1	0	0
2011	MIN	0	0	2	0	10	15	15	6	4	3
	INCR	0	2	3	0	0	3	4	1	0	0
2012	MIN	0	0	3	0	10	17	17	6	5	3
	INCR	0	2	3	0	0	3	5	2	0	0
2013	MIN	0	0	5	0	10	20	23	7	6	3
	INCR	0	2	3	0	0	3	6	2	0	0
2014	MIN	0	0	7	0	10	23	25	8	7	3
	INCR	0	2	13	0	0	3	6	2	0	0
2015	MIN	0	0	9	0	10	27	34	9	7	3
	INCR	0	3	3	0	0	3	5	2	0	0
2016	MIN	0	0	11	0	10	30	39	10	7	3
	INCR	0	3	3	0	0	3	6	2	0	0
2017	MIN	0	0	13	0	10	34	43	11	7	3
	INCR	0	5	3	0	0	3	6	2	0	0
2018	MIN	0	2	15	0	10	38	43	12	7	3
	INCR	0	5	3	0	0	3	5	2	0	0
2019	MIN	0	3	17	0	10	42	52	14	7	3
	INCR	0	5	3	0	0	3	9	2	0	0
2020	MIN	0	10	18	0	10	43	58	16	7	3
	INCR	0	5	3	0	0	2	7	2	0	0
2021	MIN	0	17	20	0	10	44	67	18	7	3
	INCR	0	4	3	0	0	1	6	2	0	0
2022	MIN	0	23	22	0	10	45	77	20	7	3
	INCR	0	5	3	0	0	0	6	2	0	0

Table 7.8. Simulation of System Operation

Data Item	Value/ information
Selected method for loading order instructions (given as input data or calculated by program)	Calculated by the program
Option used for calculation of loading order	loading order is calculated on unit by unit basis
Number of fourier coefficients used in simulations	20

As for spinning reserves, the present criterion is to keep, if possible, spinning reserves equivalent to the largest thermal unit. For future years, it has been assumed that generation capacity equal to the two largest thermal units would be kept as spinning reserves to enhance system reliability.

7.7. Economic Inputs

7.7.1. Hydro Power Plants Cost Data

WAPDA has prepared capital cost estimates for future hydroelectric power plants based on Bill of Quantities and detailed cost estimates from various pre-feasibility and feasibility studies for these projects. Unit and lump sum prices for civil works, and costs for major power plant equipment were developed and applied to the quantities for various work items. The cost estimates for the projects consist of the estimated costs for infrastructure, camps, resettlements, civil works, electrical and mechanical equipment and installations, engineering, construction and management and administration. Contingencies were then applied to these costs. The cost data for hydro power plants are listed in Table 7.9.

Table 7.9. Cost Information for Hydro Candidates

Hydro project name	Depreciable capital cost (US/kW)			Plant life (years)	Portion of IDC in total capital @ 10% p.a. (%)	Construction time (year)
	Domestic	Foreign	Total			
KALABAGH1	781.48	955.15	1736.63	50	22.67	6
KALABAGH2	781.48	955.15	1736.63	50	22.67	6
TARBELA 15–16	165.99	387.31	553.3	50	19.21	5
BASHA 1	738.42	902.52	1640.94	50	22.67	6
BASHA 2	738.42	902.52	1640.94	50	22.67	6
BASHA 3	738.42	902.52	1640.94	50	22.67	6
BASHA 4	738.42	902.52	1640.94	50	22.67	6
JINNAH	790.5	1679.7	3372.72	50	15.63	4
TAUNSA	611.2	1611.2	2222.4	50	15.63	4
KOHALA	773.34	945.19	1718.53	50	22.67	6

7.7.2. Thermal Power Plants Cost Data

The capital costs data are based on pre-feasibility study reports, feasibility study reports, Planning Commission pro forma -1 reports, plant contracts and project completion reports for respective projects. The major cost components included in the capital cost of the power plants are:

- site development
- building and structure
- steam generators and auxiliaries
- turbine generators
- instrumentation and control
- processes and services
- fuel system
- erection and commissioning
- spare parts

The specific capital cost of constructing nuclear power plants in different countries has a very wide range because of regulatory and other reasons. For example, based on recent experience of actual construction of nuclear power plants and for firm estimate, OECD has reported specific capital cost for nuclear power plant in different countries to vary from US $1000/kW to US $2870/kW (see Table 7.10). Based on these estimates, for the present analysis, the fore cost for nuclear power plant has been assumed as US $1700/kW in terms of 1993 dollars, which corresponds to a completion cost of US $2198/kW including interest during construction. For sensitivity analysis of this important parameter, a fore cost of US $2000/kW (in 1993 dollars) with completion cost of US $2586/kW has also been considered.

As for decommissioning cost of nuclear power plants it has been assumed that a fund will be created by adding 1 mills/kW·h in the O&M cost, which will be sufficient at the end of plant life for its decommissioning.

The cost data for the candidate thermal power plants are given in Table 7.11.

Table 7.10. Estimates for Overnight Capital Cost of Nuclear Power Plants in Different Countries

	U. S. $/kW (mid-1991 prices)
CSFR	960
China	1193
France	1231
USA 1	1440
USA 2	1484
USA 3	1568
Hungary	1576
Finland	1625
Korea	1632
Belgium	1746
Japan	2124
Germany	2400
UK 1	2512
UK 2	2871

Source : [83]

Table 7.11. Cost Data for Thermal Candidates

Plant name	Depreciable capital cost (US$/kW)			Plant life (years)	Non-depreciable capital cost (US$/kW)		Portion of IDC in total capital @ 10% p.a. (%)	Construction time (years)
	Domestic	Foreign	Total		Domestic	Foreign		
FOL3	326.55	979.65	1306.20	30	0	22.25	15.63	4
FOL6	288.92	866.75	1155.67	30	0	22.25	15.63	4
COAL	349.68	1049.03	1398.71	30	0	50.88	19.21	5
WFGD	410.02	1230.06	1640.08	30	0	51.9	19.21	5
DCOL	381 19	1524.77	1905.96	30	40.07	0	15.63	4
CCIG	172.81	691.23	864.04	25	0	18.56	11.92	3
GTIG	83.55	473.45	557.00	20	0	28.13	8.08	2
NUCL	659.51	1538.86	2198.37	30	0	90	22.67	6

7.7.3. Fuel Prices and Future Escalations

The fossil fuel prices used in the present study are given in Table 7.12. As for nuclear fuel cost, based on recent study by OECD (Ref.: OECD 1994], it has been assumed that for cost of natural Uranium and fuel cycle services, as given below, the nuclear fuel cost in 1993 US dollars will be equivalent to 4.8 mills/kW·h.

Uranium price : US $25/lb $U_3 O_8$

Enrichment cost : US $100 /kg SWU

Fuel fabrication cost : US $220/kg U

Table 7.12. Prices of Fossil Fuels

Fuel	Fuel Cost [1]
Furnace Oil [2]	US $104/ ton
Domestic Coal	US $71.4 / ton
Imported Coal [3]	US $56.3 / ton
Domestic Gas [4]	US $2.33/ 000 Cu.ft
Imported Gas [4]	US $2.33/ 000 Cu.ft

1. In terms of base year (1992–93) prices
2. Excluding the transportation cost for furnace oil (which has been estimated to be $0.028/ton-km for long distance transportation by rail and $0.015/ton-km by pipeline) from Karachi to mid-country.
3 Excluding port handling cost (which has been estimated to be $6.8/ton to allow for the capital cost recovery of post handling facilities)
4. Excluding transmission cost of natural gas (which has been estimated to be $0.65/ cu. ft) either from the coast (for imported gas) or from the indigenous field, based on the average incremental cost of expanding the existing transmission system

Based on [20]

For estimation of the fuel prices, as a first step the prices of imported fossil fuels viz. coal, furnace oil and natural gas, have been assumed based on world market CIF prices at port of entry. All these costs are CIF prices at or near Karachi. Then the costs for port handling facilities is estimated for the respective fuels, if applicable. The transportation/transmission costs for oil/gas have been added to these costs to make the fuel available at mid-country.

Adopting an appropriate projection for fuel prices is a contentious issue because most of the experts have varying perceptions on future fuel prices due to uncertainty of future economic and political conditions in the world. As described in Chapter 3, a set of projections for future fuel prices has been developed keeping in view the projections by various international organizations. The international oil prices are assumed to increase in real terms at 1% p.a. during 1995–2000, 2% p.a. during 2001–2010 and 2.7% p.a. thereafter. The price of imported gas has been assumed to increase at the same rates as for oil. The imported coal prices have been assumed to increase in real terms at 1% p.a. throughout the study period. In the case of indigenous fuels, in line with the present policy of the government, the prices are linked to international energy prices. As such, the same growth rates have been used for indigenous fuel prices.

No escalation in nuclear fuel prices has been assumed in real terms in nuclear fuel costs in view of recent trends reported by various agencies on Uranium supply and demand situation in the world [83, 84]. However, sensitivity analysis has been done using 1% p.a. escalation in real terms in the nuclear fuel cost.

7.7.4. Discount Rate

The discount rate plays a crucial role in selection of future power plants for formulating power capacity expansion plans through economic optimization. Higher discount rates reduce the effect of benefits that are far away in time and hence would penalise plants with higher initial capital costs but with lower or no fuelling costs, e.g. hydro and nuclear plants. The choice of an appropriate value for discount rate is the most complex issue in power system expansion planning. The central economic planning bodies in every country usually recommend an appropriate value for discount rate. One point often ignored is that the ELECTRIC/WASP based analysis is done in constant monetary terms and the discount rate and other temporal economic parameters are to be specified in real terms. The real discount rate may be taken as equal to the opportunity cost of money in real terms in an economy or equal to the real cost of borrowing the investment funds. The real discount rate used in various countries vary from 4–6% per annum in developed countries to 8–12% per annum in developing countries (see Table 7.13).

The discount rate used in the present study for all types of costs is assumed to be 10% p.a. in real terms in line with the general practice in Pakistan. However, sensitivity studies with various discount rates ranging from 11% to 15% have also been performed to investigate the effect of this important parameter on the results of the study. The data on the economic parameters are given in Table 7.14.

7.7.5. Cost of Energy Not Served

The expected energy not served (ENS) is the probabilistically determined amount of electrical demand per year that is not supplied owing to generating capacity deficiencies and/or shortages in basic energy supplies, such as hydroelectric energy. The ENS is calculated in WASP through the probabilistic simulation process which accounts for all combination of random forced outages of generating units experienced by the generating system. ENS is used in the objective function just as an operating cost. If the ENS cost is set to zero, other constraints determine the minimum amount of capacity required to be added; on the other hand, if the ENS cost is relatively high and the generating system is somewhat unreliable, the cost of adding new capacity may be less than the total cost of unserved energy. Therefore, it is very important to select a proper value of ENS cost. A detailed analysis carried out for the cost of electricity shortages in the industrial sector in Pakistan [87] has estimated that the industry suffers a loss of US $0.9 per kW·h shortage of electricity. In comparison, the outage cost in the industrial sector have been estimated at US $2.02/kW·h in Argentina, at US $2.56/kW·h in Indonesia, and in the range of US $1.86–3.39/kW·h in Colombia [88]. In the present study, the ENS cost has been assumed as US $1.0/kW·h.

Table 7.13. Real Discount Rates Used in Various Countries for Evaluation of Power Projects (% p.a.)

Industrialised Countries	Discount Rate	Developing Countries	Discount Rate
Austria	5	Brazil	8 , 10
Belgium	8.6	China	10
Canada	4.8–6	Czechoslovakia	5
Denmark	5–7	Hungary	12
Finland	5	India	10
F. R. Germany	5	Indonesia	10
Italy	5	Korea, Rep. of	8
Japan	5	Poland	5
Netherlands	5	Yugoslavia	8
Norway	4		
Portugal	10		
Spain	5–10		
Sweden	7		
Switzerland	7		
Turkey	10		
UK	5–8		
USA	7		

Sources of Data: [83, 85, 86]

7.8. Results of Electricity Generation System Expansion Analysis

7.8.1. The Reference Case

In the formulation of the least-cost Reference Case expansion plan, electricity demand projected in the Reference Demand Scenario has been used along with a number of constraints on indigenous energy resource development, fuel supply limitations, system reliability and other physical constraints, and cost assumptions, as discussed above. The least-cost plan has been worked out through an iterative process with a number of successive runs of BALANCE and ELECTRIC modules of the ENPEP package (as discussed in Chapter 6). This case is not only the least-cost expansion plan for future development of the electricity sector in Pakistan, under specified assumptions; it also represents the most plausible case under the present perceptions for evolution of the energy and electricity sector in the country.

Table 7.14. Economic Parameters Input Data

Data Item	Value/information
Base year for cost discounting calculations	1993
Base year for cost escalation	1993
Option for discount rates(single or individual)	Single
Discount rate on investment costs domestic foreign	 10% 10%
Discount rate on operating costs domestic foreign	 10% 10%
Multiplier of foreign costs(if different to 1.0)	–
Annual escalation ratio of investment cost per candidate domestic foreign	 1 0 1 0
Annual escalation on total operating cost by each thermal fuel type domestic foreign	 0 0
Cost of energy not served($/kW·h)	1.0
Critical value of the loss- of- load probability	Not used
Salvage value option	1

The future additions of electricity generation capacities for the Reference Case expansion plan are presented in Table 7.15. This plan suggests development of about 84 000 MW of power generation capacity over the next 30 years period, comprising: Hydro 11 500 MW, Nuclear 13 200 MW, Coal Steam 15 000 MW, Coal FBC 1000 MW, Oil Steam 15 000 MW, Gas fired Combined Cycle 20 250 MW, and Gas fired Combustion Turbines 8100 MW. Figure 7.7 shows the future evolution of total installed power capacity and peak demand for this case.

The shares of different power generation technologies in the total installed capacity are shown in Table 7.16. It may be noted that the share of hydro power in the total installed capacity will decrease from 34% in 1993 to about 16% by the year 2022, while the share of natural gas based power capacity will decrease from 41% now to 31% in 2003 and then stay at a level of 30–35% throughout the planning period. The share of coal based capacity steadily builds up to 18% by the year 2022. The share of nuclear power in total installed capacity increases gradually from about 1% now to about 5% by the year 2003, 12% in 2013 and to about 15% by the year 2022. The remaining installed capacity is based on oil.

The corresponding electricity generation mix is given in Fig. 7.8. It may be noted that the nuclear power contributes about 19% of the total electricity generation in the terminal year. Although the share of hydroelectric generation decreases during the study period, the combined share of the non-fossil sources (hydro and nuclear) remains close to 30–40% of the total generation throughout the 30 year period.

Table 7.15. Cumulative Electricity Generation Capacity Additions (MW)

(Reference case)

	1993	2003	2013	2022
Hydro	0	144	10 622	11 462
Oil	0	0	0	15 000
Gas				
Combustion Turbine	0	200	2700	8100
Combined Cycle	0	2700	10 350	20 250
Coal				
FBC	0	400	1000	1000
Steam	0	600	4800	15 000
Nuclear	0	600	5400	13 200
Total	0	4 644	34 872	84 012

Table 7.16. Future Installed Electricity Generation Capacity Mix By Fuel

(Reference Case)

Year	**1993**	**2003**	**2013**	**2022**
Total Installed Capacity (MW)	8547	20 296	45 942	91 615
% Shares				
Hydro	33.77%	32.82%	29.74%	15.83%
Oil	24.00%	25.19%	10.67%	19.89%
Gas	41.28%	31.36%	34.18%	31.89%
Coal	0.14%	5.73%	12.95%	17.63%
Nuclear	0.82%	4.90%	12.46%	14.76%

Table 7.17. Expected Future Fuel Requirements (000 TOE)

(Reference case)

YEAR	OIL	GAS	COAL
1993	2911	5242	18
2003	5188	7930	1700
2013	5257	16 813	9398
2022	18 231	29 517	26 942

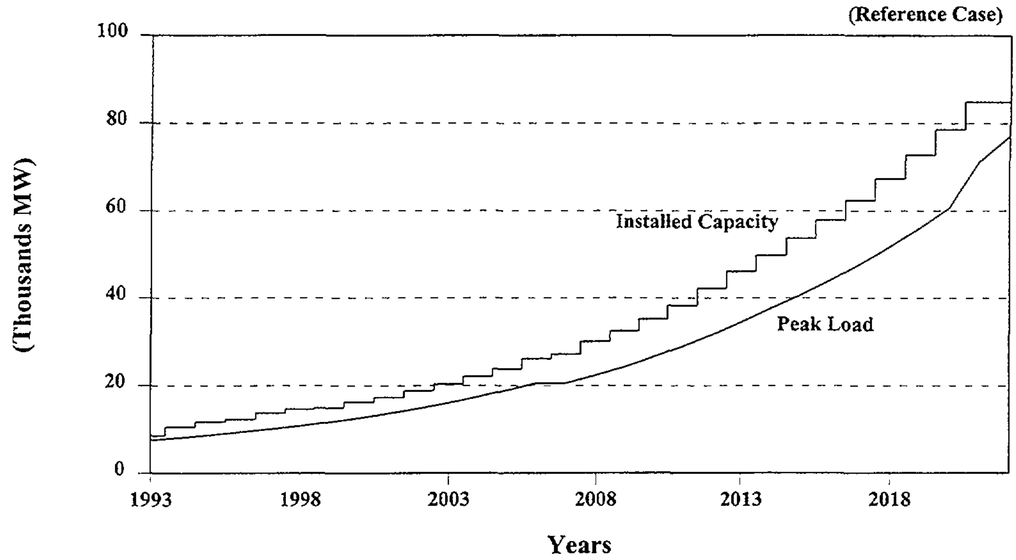


FIG. 7.7. Installed Electricity Generation Capacity and Peak Load

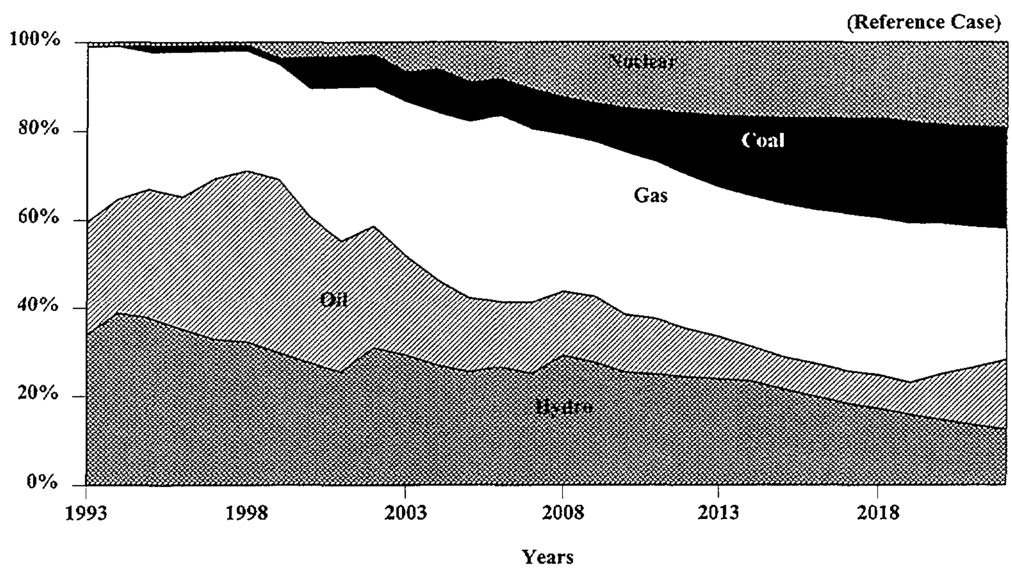


FIG. 7.8. Future Electricity Generation Mix By Fuel

The energy resource requirements for operation of the electricity generation system developed in the Reference Case are given in Table 7.17. It may be noted that in the terminal year 29.5 million TOE of natural gas would be required to operate the gas fired combined cycle units and the combustion turbines. In addition, 18.2 million TOE of imported oil and 27 million TOE of imported coal would be required for power generation in the terminal year. However, it is expected that the recently identified Thar coal field will be gradually developed and a large fraction of coal requirements for power generation will be met from indigenous supplies. Nuclear power will be contributing about 20% of power generation in the year 2022, replacing 21.7 million TOE of fossil fuel consumption for power generation.

The detailed output of the ELECTRIC module of ENPEP for the Reference Case is given in Appendix F.

7.8.2. Alternative Expansion Plans

In view of various uncertainties about future evolution of energy/electricity demand and supply system, e.g., future electricity demand, nuclear power development, possibility of importing natural gas and realization of efficiency improvement potential, it is necessary to explore alternative plans for expansion of electricity generation system. These alternative plans will also provide insight to the merits of the expansion plan formulated in the Reference Case. Accordingly, in addition to the Reference Case, the following four alternative expansion plans have been worked out using the ELECTRIC module of ENPEP .

1) Alternative I (Nuclear Moratorium Case)

2) Alternative II (Reference Case but no gas imports considered)

3) Alternative III (Energy Efficiency Case)

4) Alternative IV (Optimistic Case)

5) Alternative V (Reference Case with private sector plants)

The Alternative I differs from the Reference Case in terms of the extent of nuclear power capacity allowed for future expansion. The Reference Case assumes that the present plans for nuclear power capacity additions will be implemented resulting in the construction of about 13 200 MW nuclear power capacity by the year 2022 whereas the Alternative I assumes a moratorium on construction of new nuclear power capacity.

The capacity mix worked out in the Alternative expansion plan I is given in Table 7.18. The programmes for building-up of (a) hydro capacity, (b) thermal capacity based on coal, and (c) thermal capacity based on natural gas worked out in this case are essentially identical to that in the Reference Case. Only the nuclear power capacity additions in the Reference Case have been replaced by oil fired plants. The future electricity generation mix for Alternative I is shown in Fig. 7.9. It may be noted that since nuclear power plants in this case have been replaced by oil fired plants, the share of electricity generation based on oil is 34% in the terminal year compared to 16% in the Reference Case.

Table 7.18. Future Installed Electricity Generation Capacity Mix By Fuel

(Alternative I)

Year	**1993**	**2003**	**2013**	**2022**
Total Installed Capacity(MW)	8547	20 296	45 942	91 615
% Shares				
Hydro	33.77%	32.82%	29.74%	15.83%
Oil	24.00%	25.19%	22.43%	34.30%
Gas	41.28%	31.36%	34.18%	31.89%
Coal	0.14%	8.68%	12.95%	17.63%
Nuclear	0.82%	1.95%	0.71%	0.35%

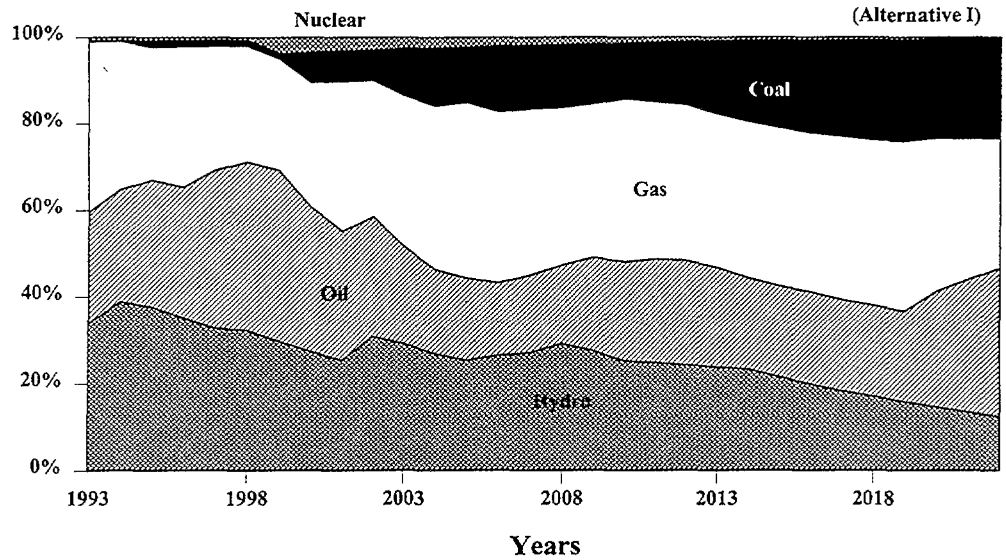


FIG. 7.9. Future Electricity Generation Mix By Fuel

In Alternative II, it has been assumed that imported natural gas option is not available while all the other assumptions are the same as that for the Reference Case. The capacity mix for the Alternative II is shown in Table 7.19. It can be noted that the share of hydroelectric, nuclear and coal based capacities are the same as that in the Reference Case while the share of gas based capacity has decreased from 41% in the base year to 18% in the terminal year as compared to 32% in the Reference Case. The share of oil fired capacity increases a little bit from the present value of 24% to 25% in 2003, then decreases to 18% in 2013 and again increases to 34% in the year 2022. Figure 7.10 shows the future electricity generation mix for this case. The share of gas fired capacity has significantly decreased in this case from the present level of 41% to a level of 18% in the terminal year.

Table 7.19. Future Installed Electricity Generation Capacity Mix By Fuel

(Alternative II)

Year	1993	2003	2013	2022
Total Installed Capacity (MW)	8547	20 296	46 192	91 665
% Shares				
Hydro	33.77%	32.82%	29.58%	15.82%
Oil	24.00%	25.19%	18.41%	33.62%
Gas	41.28%	31.36%	26.74%	18.18%
Coal	0.14%	5.73%	12.88%	17.62%
Nuclear	0.82%	4.90%	12.39%	14.75%

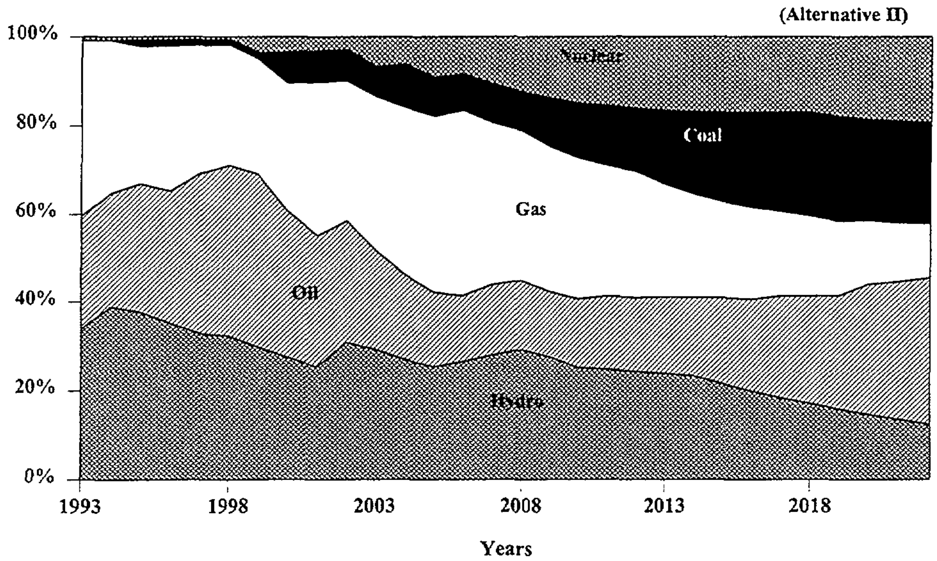


FIG. 7.10. Future Electricity Generation Mix By Fuel (GW·h)

Alternative III uses the electricity demand projected in the energy efficiency scenario of MAED. All assumptions on the supply side are the same as that for the Reference Case. This case considers that all the conservation measures that are technically feasible will be implemented. In addition to end-use level measures, the T&D losses are also assumed to be lower by 3 percentage points at the end of planning horizon compared to that in the Reference Case. As a result, the peak demand and the total capacity requirements are some 20% lower in this case compared to those in the Reference Case.

The projected installed capacity mix for Alternative III for future years is given in Table 7.20 and Fig. 7.11. It may be noted that the nuclear power capacity in this case remains 13 200 MW despite lower total capacity requirements. The hydroelectric capacity and the gas based power capacity also remain the same as that in the Reference Case. The corresponding electricity generation mix for this case is given in Fig. 7.12. It may be noted that the share of hydroelectric generation in this case decreases from 34% in the base year to a level of 15% in the terminal year while the share of oil based generation decreases from the present level of 26% to some 2% in the year 2022. The share of electricity generation based on gas remains in the range of 25% to 39%. The shares of electricity generation based on nuclear and coal plants grow from the present small levels (1% nuclear and 0.1% coal) to 24% and 27% respectively in the terminal year.

As an extreme electricity demand case, Alternative IV power system expansion case has been worked out which assumes higher electricity demand as worked out in the Optimistic Scenario of MAED. Since the contribution of hydro, nuclear and gas are already at their maximum feasible levels, the additional capacity required to meet higher peak demand in this case has to be based on imported coal and oil. The total additional capacity required in this case is 147 000 MW as compared to 84 000 MW in the Reference Case. The installed electricity generation capacity mix for Alternative IV is given in Table 7.21 and Fig. 7.13. It may be noted that the oil fired capacity in this case is about 70 000 MW as compared to about 18,000 MW and coal fired capacity is 25 000 MW as compared to 16 000 MW in the Reference Case. The electricity generation mix for this case is shown in Fig. 7.14. It may be noted that the oil based electricity generation dominates towards the end of the study period and its share becomes about 40% in the year 2022. The shares of hydroelectric and gas based electricity generation decreases from the present levels of 34% and 39% to 7% and 20%, respectively, in the terminal year while the shares of nuclear and coal based electricity generation increase to a level of 12% and 21% respectively in the year 2022.

A number of thermal power plants are being planned in the private sector, some of which are expected to become operational in the near future. In the reference case it was assumed that apart from Hubco plant, which is considered as committed, all the private sector power capacity would be based on the candidates selected in the optimum expansion plan. However, very recently 16 power projects in the private sector with a total capacity of 4320 MW have achieved financial closure and actual construction has also been started on some of these projects. As such, under the latest situation these plants should be considered as committed plants. Alternative V has therefore been analysed to reflect the latest situation of power sector development in Pakistan.

Table 7.20. Future Installed Electricity Generation Capacity Mix By Fuel

(Alternative III)

Year	1993	2003	2013	2022
Total Installed Capacity(MW)	8547	19 046	39 942	75 115
% Shares				
Coal	0.14%	2.95%	11.89%	21.50%
Gas	41.28%	30.00%	27.29%	36.90%
Oil	24.00%	26.85%	12.28%	4.29%
Nuclear	0.82%	5.22%	14.33%	18.01%
Hydro	33.77%	34.98%	34.20%	19.31%

Table 7.21. Future Installed Electricity Generation Capacity Mix By Fuel

(Alternative IV)

Year	1993	2003	2013	2022
Total Installed Capacity(MW)	8547	21 852	62 342	154 565
% Shares				
Coal	0.14%	13.55%	21.09%	16.27%
Gas	41.28%	28.67%	24.55%	20.42%
Oil	24.00%	23.40%	23.26%	45.17%
Nuclear	0.82%	4.55%	9.18%	8.75%
Hydro	33.77%	29.83%	21.91%	9.38%

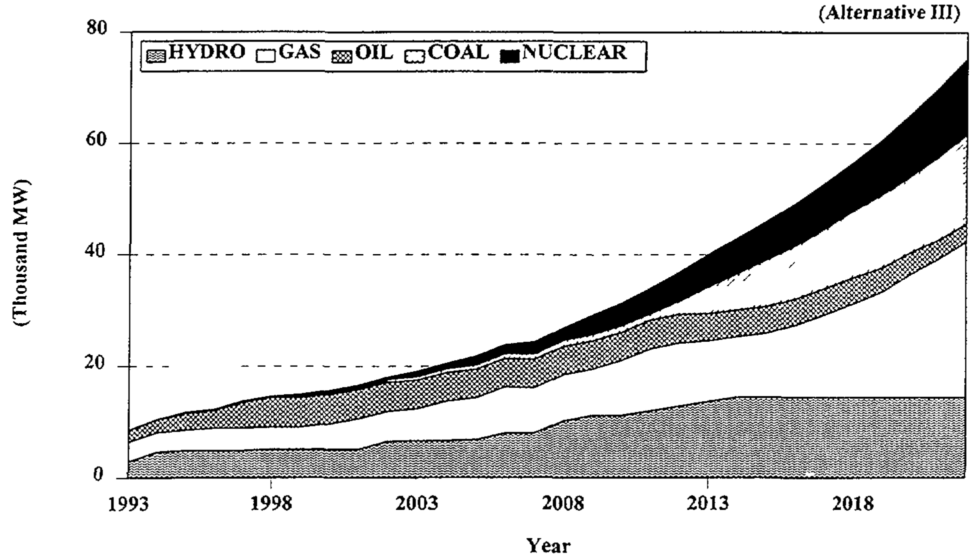


FIG 7.11 Projected Installed Electricıty Generation Capacity

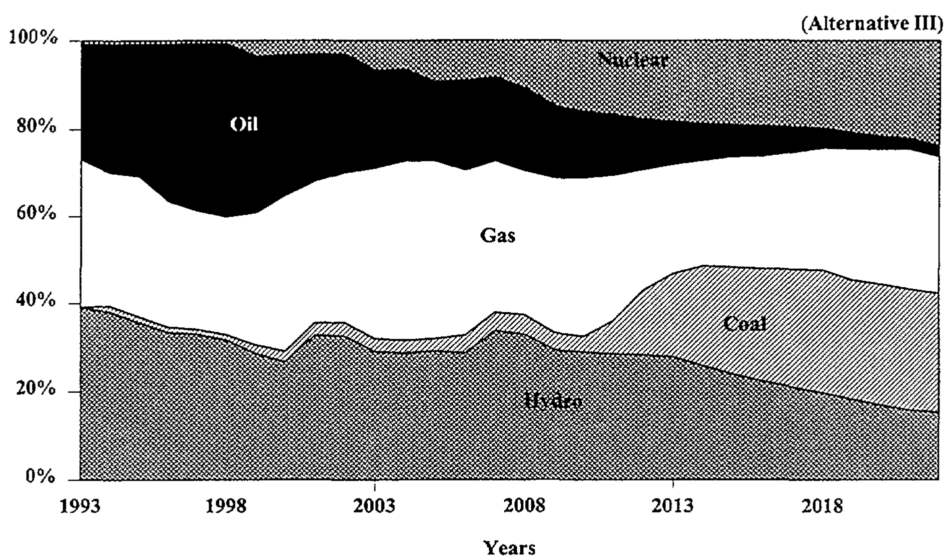


FIG 7.12 Future Electricity Generation Mix By Fuel

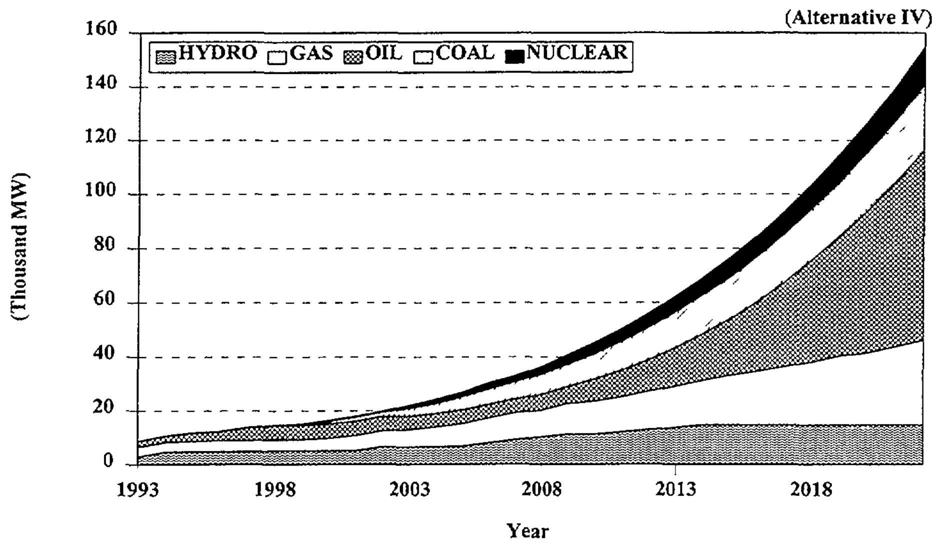


FIG. 7.13 Projected Installed Electricity Generation Capacity

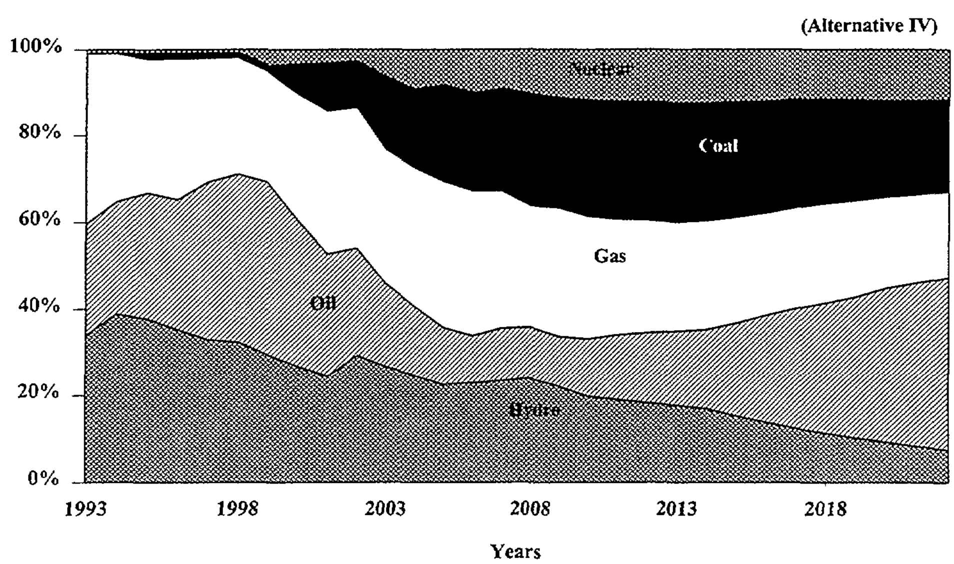


FIG 7.14. Future Electricity Generation Mix By Fuel

It has been assumed that out of 4320 MW power capacity in the private sector 1758 MW will become operational by end of 8th Five Year Plan period and the remaining 2562 MW will become available during the 9th Five Year Plan period. This additional committed capacity has changed the optimal solution during the initial years of the study period. The combined cycle plants appearing in 2000–2003 in the optimum solution for the Reference Case have been delayed. The first nuclear power plant has also been delayed and now appears in 2004 instead of 2003 in the Reference Case. However, the total capacity based on combined cycle power plants and nuclear power plants remains same as that in Reference Case. The number of coal and oil based plants added in the plan has been reduced to 23 and 21 respectively from 25 each in the Reference Case. Total number of combustion turbines has also been reduced in this case. The total installed capacity, however, remains almost same at 91 600 MW. Table 7.22 gives the capacity mix for this case.

Table 7.22. Future Installed Electricity Generation Capacity Mix By Fuel

(Alternative V)

Year	1993	2003	2013	2022
Total Installed Capacity(MW)	8547	20 372	45 912	91 635
% Shares				
Coal	0.14%	9.24%	11.91%	17.75%
Gas	41.28%	19.58%	29.79%	31.69%
Oil	24.00%	37.24%	16.07%	19.97%
Nuclear	0.82%	1.94%	12.47%	14.76%
Hydro	33.77%	32.00%	29.78%	15.83%

7.9. Investment Requirements

Table 7.23 gives the cumulative investments and cumulative system operation costs (O&M and fuel costs) over the next 30 years period for all the five cases. In the Reference Case, the cumulative investments for capacity additions have been worked out as US $108 billion and the cumulative system operation costs as US $172 billion. Compared to Alternative I, the cumulative investments in the Reference Case are US $15 billion higher because of the fact that capital costs of nuclear power plants included in the Reference Case are relatively higher compared to that for fossil fuel based power plants .On the other hand, the system operation costs in the Reference Case are lower by about US $33 billion as compared to that in the Alternative I. This difference is due to low fuelling costs of nuclear power plants. The sum of cumulative investment and operation costs is thus lower by US $18 billion in the Reference Case as compared to that in the Alternative I scenario. The cumulative investments in the Alternative II are about US $112 billion and the cumulative operation costs are US $176 billion. It may be noted that these values are not much different from those for the Reference Case.

Table 7.23. Cumulative Investments and Operation Costs

(Million US dollars)*

	Investments	Operation Cost	Total
Base Case	108 021	171 764	279 785
Alternative-I	93 450	204 702	298 152
Alternative-II	111 815	175 514	287 329
Alternative-III	89 622	137 037	226 659
Alternative-IV	183 341	275 677	459 018

* US $ of 1993

If electricity demand grows to the levels as envisaged in the Optimistic Scenario, the cumulative investments required for building power capacity will be US $183 billion (which are about 70% higher than those in the Reference Case) and cumulative operation costs will be US $276 billion (which are about 60% higher than those for the Reference Case). However, if efficiency improvement potential is realized and the total electricity demand is lower, as in the Energy efficiency scenario of MAED, the cumulative investments required over the planning period are about 17% lower than those required for the Reference Case and the cumulative operation costs in this case are about 20% lower than those for the Reference Case. It should be pointed out that the investment requirements for efficiency improvement measures have not been worked out in the present study, however, it is felt that these costs are lower than the additional costs involved in the construction of new power plants and their operation in the Reference Case.

7.10. Fuel Import Dependence

Due to limited indigenous energy resources, large quantities of oil are being imported to meet energy requirements for about the last two decades. The share of imported oil in total oil consumption of the country was in the range of 85–90% until early 1980s. This share has now decreased to about 75% due to relatively increased petroleum exploration and development activity in last several years. Still, the oil import bill is siphoning off a large portion of the country's export earnings. The oil import bill in 1992–93 was US $1.5 billion which was equivalent to 22% of the total export earnings of the country.

The comparison of total as well as imported fossil fuel requirements for power generation for various alternative cases is given in Table 7.24. It may be noted that the imported fossil fuel requirements, in all of the alternative cases as well as that in the Reference Case, account for about 96–98 % of the total fossil fuel requirements in the terminal year. The imported fossil fuel requirements in the terminal year are found to be 72 million TOE in the Reference Case. It may be noted that in order to meet the same electricity demand in 2022, the imported fossil fuel requirements are higher by about 30% in the Alternative I as compared to those in the Reference Case. These higher imported fuel requirements are due to the assumption of non availability of nuclear power plants in Alternative I.

Table 7.24. Total and Imported Fossil Fuel Requirements

(000 TOE)

Year	Reference Case		Alternative-I		Alternative-II		Alternative-III		Alternative-IV	
	Total	Imported	Total	Imported	Total	Imported	Total	Imported	Total	Imported
1993	8171	2844	8171	2844	8171	2844	8171	2844	8171	2844
2003	14 818	10 420	15 827	11 429	14 818	10 420	13 295	8719	16 730	12 723
2013	31 469	27 273	40 277	35 476	32 263	27 647	24 352	20 163	51 167	47 085
2022	74 693	72 285	96 530	93 930	78 161	75 584	53 555	52 040	151 754	148 833

For higher future electricity demand in Alternative IV, all the additional capacity additions will be based on imported fuels and thus the imported fuel requirements in this case are almost double than those in the Reference Case for the year 2022. If the future electricity demand is reduced through energy conservation measures, as in Alternative III, the imported fuel based capacity additions will be lower and thus about 20 million TOE of imported fuel requirements in 2022 can be avoided in this case. It may be mentioned here that imported coal used in the Reference, Alternative-I, Alternative-II and Alternative-III cases amounts to about 25 million TOE while that for Alternative IV is 40 million TOE. About 17 million TOE of these coal requirements may be met through indigenous coal if the recently discovered Thar coal field is developed.

7.11. Sensitivity Analysis

In order to study the effect of discount rate, capital cost of nuclear power plant and fuel costs of fossil fuels on the power system expansion programme worked out in the Reference Case, various sensitivity analyses have been performed. The results of these sensitivity analyses are described below.

i) Discount rate

Sensitivity analysis on the generation expansion programme has been performed by increasing the discount rate for both capital cost and the operating cost from the reference value of 10% to 11%, 12%, 13%, 14% and 15%. The power generation expansion programme remains unchanged up to a discount rate of 14%. However, at a discount rate of 15%, the first nuclear power plant shifts to one year later than that in the Reference Case.

ii) Capital Cost of Nuclear Power Plant

Sensitivity analysis has also been carried out for the capital cost of nuclear power plant by increasing the fore cost of the nuclear power plant. It has been found that there is no change in the least cost electricity generation expansion plan up to a value of US $2150/kW for fore-cost of nuclear power plant. In other words, the plan remains unchanged for 26% higher capital cost of the nuclear power plant. The candidate nuclear power plant is delayed by one year if the fore cost of the plant is increased to US \$2200/kW as compared to US \$1700/kW as considered in the Reference Case.

iii) Fuel Cost Escalations

The Reference Case considers fuel costs escalations as given in Section 7.7.3. These future projections of fossil fuel prices may appear favourable to nuclear power. As such, sensitivity analysis of the least cost expansion plan in the Reference Case has also been carried out by assuming no change in future prices for fossil fuels. It has been found that the system expansion programme and hence the nuclear power plants addition schedule does not change even if no escalation is assumed in fossil fuel prices.

iv) Nuclear Fuel Cost

Although, recent trends in the international market do not indicate any significant increase (in real terms) in future prices of nuclear fuel, in order to assess the impact of any possible increase in nuclear fuel cost, sensitivity analysis has also been carried out by assuming 1% p.a. real escalation in nuclear fuel cost. It has been found that even with this increase in nuclear fuel cost the optimum solution in the Reference Case remains unchanged.

Yet another sensitivity analysis has been performed by simultaneously using 1% p.a. real escalation in nuclear fuel cost and increasing the capital cost of nuclear power plants. Under this extreme worst case assumption, the nuclear power development schedule in the Reference Case does not change up to a level of US \$2010/kW (i.e., optimum solution remains unchanged even with 18% higher capital cost and 1% p.a. real escalation in fuel cost).

Table 7.25 summarises the results of the sensitivity analysis. It is clear that the optimal solution in the Reference Case is robust under a wide range of values for important parameters.

7.12. Conclusions

The preceding analysis of power generation capacity expansion has shown that all possible energy supply sources will be required for electricity generation in order to meet the future demand for electricity. Furthermore, in spite of vigorous efforts on the development of indigenous energy resources, a large fraction of future electricity generation capacity will have to be based on imported fuels.

The analysis has shown that nuclear power can significantly help in reducing the energy import dependence of the country. Although, nuclear power plants are relatively expensive to build, their operating costs are very small compared to that of fossil fuel based power plants. This makes the overall cost economics of nuclear power plants very attractive. However, besides being capital intensive nuclear power plants require large number of skilled manpower and other infrastructure facilities for their construction. As such only a gradual development of nuclear power can be implemented.

The least cost plans worked out for the Reference Case and the Alternative cases show that all the maximum allowed nuclear power capacity (13 500 MW) is part of every least cost expansion plan whenever this option is allowed. Further, the proposed programme for nuclear power development is quite insensitive to variation in important parameters (capital cost and discount rate). It is therefore clear that an all out effort should be made to implement the envisaged nuclear power development plan.

Table 7.25. Results of Sensitivity Analysis

Sensitivity Parameter	Reference Case Value	Result of Sensitivity Analysis
Discount rate	10% p.a. (in real terms)	Solution remains unchanged for a value of 10% – 14% p.a. However, at a discount rate of 15% p.a. the nuclear power programme is deferred.
Capital Cost of Nuclear Power Plants	US $1700/kW (fore cost without IDC)	The optimal solution remains unchanged up to a fore cost of US $2150/kW. The program starts rejecting the nuclear power development at a fore cost of US $2200/kW.
Fuel Cost Escalations (in real terms)	Oil : 1% p.a. during 1995–2000 2% p.a. during 2001–2010 2.7% p.a. during 2011–2022 Gas : Same as oil Coal : 1% p.a. throughout the study period	The optimal solution remains unchanged by assuming no escalation in future fossil fuel prices.
Nuclear Fuel Cost	Constant in real terms	Solution remains unchanged for a real escalation of 1% p.a. throughout the study period in the nuclear fuel cost.
Capital and Fuel cost of Nuclear Power Plant	i) Capital cost = US $1700/kW ii) constant fuel cost	Solution remains unchanged by simultaneously increasing nuclear fuel cost at 1% p.a. in real terms and the fore cost of nuclear power plants up to a level of US $2010/kW.

Chapter 8

ENVIRONMENTAL ANALYSIS OF ALTERNATIVE ELECTRICITY EXPANSION PLANS

8.1. Introduction

Among the various factors responsible for degradation of the natural environment, the most polluting source is the use of energy. Presently more than one-third of total energy demand, in Pakistan, is being met by non-commercial (traditional) fuels and the remaining from natural gas, coal, oil and electricity. The use of non-commercial fuels is resulting in environmental problems such as deforestation and loss of organic nutrients to soil due to burning of animal dung and agricultural wastes while emission of various gases (e.g. SO_2, NO_x, CO_2 etc.) from the supply and use of commercial fuels is the major environmental concern.

In this part of the analysis the environmental implications of only the electric sector in Pakistan has been examined because of the following:

(a) In the present (base year 1992–93) consumption of commercial energy in Pakistan more than one-third is used for electricity generation. About 56% of the present electricity generation is based on fossil fuels which gives rise to emission of 210 thousand tons of SO_2, 80 thousand tons of NO_x, and 26 million tons of CO_2. The power sector shares in the total country's emissions of SO_2, NO_x, and CO_2 are about 27%, 17% and 28% respectively. These emissions and other wastes are expected to increase substantially in the coming decades due to the foreseen increase in electricity production which will increasingly be based on fossil fuels.

(b) The power sector is an organised sector and it is easier to apply alternative strategies for environmental emission reductions (e.g. fuel substitution, application of emission control devices, etc.) compared to other sectors.

(c) Country specific data (e.g. emission factors, etc.) are not available/reliable for energy supply and use facilities of various economic sectors such as Mining, Transportation/Transmission, Residential, Manufacturing, Construction, etc.

For the present analysis, the IMPACTS module of ENPEP has been used to compare alternative plans for expansion of the electric sector in Pakistan on the basis of environmental emissions. IMPACTS can compute the environmental burdens and resource requirements of the whole energy system. For each facility of energy supply and use, IMPACTS can calculate the quantity of the pollutants emitted to air, water and earth surface and costs to their control.

8.2. Environmental Legislative Framework for Power Sector

The environmental issues have started receiving considerable attention in Pakistan during the last few years. So far, most of the efforts have been directed towards creating awareness about environmental issues. However, various legislative and administrative measures have been taken recently in order to minimize the environmental degradation.

The Environment and Urban Affairs Division (EUAD) was established in 1974 and was given responsibility for formulating national environmental policy. The promulgation of Pakistan Environmental Protection Ordinance (1983) was a major step to check the environmental degradation in the country. As a result of the ordinance, the Pakistan Environmental Protection Council (PEPC), Pakistan Environmental Protection Agency (PEPA) and four Provincial Environmental Protection Agencies (EPA's) were established. Recently, Ministry of Environment, Urban Affairs, Forestry and Wildlife has been constituted by merging and consolidating divisions of various ministries including EUAD. Now, PEPC the is the supreme body responsible for formulating environmental policy in the country and the Ministry of Environment, Urban Affairs, Forestry and Wildlife provides technical assistance to PEPC and coordinates all the activities, in Pakistan, relating to environment.

In August 1993, PEPA, with the approval of PEPC, established the National Environmental Quality Standards that imposes stringent restrictions on atmospheric emissions and municipal wastes [24]. Since the power sector has now been declared as an industry, the standards relating to industries would also be applicable to power projects. The Provincial EPA's are working on the ways in which they can monitor and enforce these standards.

8.3. Environmental Impacts of Various Electricity Generation Technologies

Electricity can be generated from a variety of primary energy sources — fossil fuels (coal, oil and natural gas), uranium, hydro and other renewables (solar, wind, etc.). Use of every one of these primary sources damages the natural environment (soil or water or atmosphere). Various pollutants are emitted from different steps of fuel chains such as extraction/ mining, refining, transportation and combustion. In the present analysis a comparison has been made at the power plant level only.

8.3.1. Fossil Fuels

Among the environmental impacts associated with fossil fuels, the important impacts having local, regional and global implications are urban/ photochemical smog, acid rain, and the possibility of global warming due to the greenhouse effect. All of these are caused by emission of gaseous pollutants during fossil fuel combustion. The combustion by products include sulphur dioxide and nitrogen oxides which contribute to acid rain, and carbon dioxide which is the major contributor to global warming. Considerable technological progress has been made to reduce the emissions of sulphur dioxide and nitrogen oxides from fossil fuel fired power plants, but incorporation of such technologies increase the electricity generation cost from these plants by 15–20%.

Table 8.1 compares emissions of major pollutants from gas, oil and coal based power plants. The power technologies considered in this comparison are gas fired combined cycle, oil fired steam power plants and conventional coal fired steam power plants without FGD. Among the fossil fuel based power plants natural gas fired combined cycle power plant is the cleanest technology. It gives rise to very little emissions of SO_2 while its associated emissions of NO_x and greenhouse gases are also relatively smaller than those corresponding to oil and coal fired technologies. Oil fired power plants produce SO_2, NO_x and CO_2 in large quantities. The emissions of SO_2 are dependent on the sulphur content of oil which for residual fuel oil is around 3%. Oil fired plants also produce considerably large quantities of liquid waste which has to be disposed off properly to avoid its mixing with surface and ground water natural sources.

Table 8.1. Emission of Major Pollutants Per GW/a of Electricity Generation From Various Power Generation Options in Pakistan (Plant Level Only)

	Coal (Without FGD)	Oil (HSFO)	Gas (Combined Cycle)	Nuclear (LWR)
Non-Radioactive Emissions (Thousand Tons)				
SO_2	52.4	150.2	0.02	–
NO_X	32.4	28.5	13.2	–
Particulates	120.1	2.7	0.5	–
CO_2	7927.8	6824.0	5247.0	–
Liquid Waste	876.0	525.6	350.4	–
Solid Waste	480.5	–	–	–
Radioactive Emissions (Tera Becquerel)				
Kr-85 (Air)	–	–	–	72.0
Xe-133 (Air)	–	–	–	180.0
H-3 (Air)	–	–	–	28.0
H-3 (Water)	–	–	–	62.0
Other Radionuclides	n.a.	n.a.	n.a.	7.7

n.a : not available
Source: Based on [Ref. 20, 89 & 90]

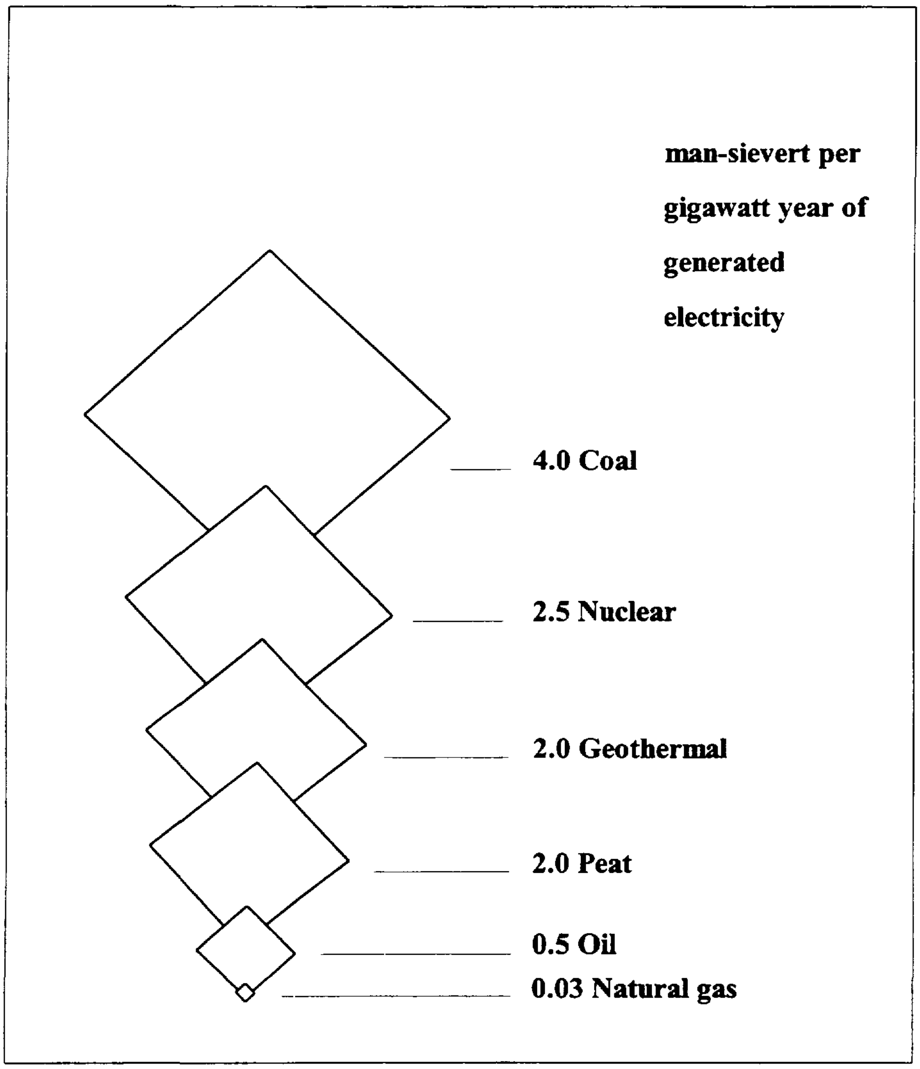
By far the most polluting technology is the coal based power generation. Besides large atmospheric emissions, coal fired power plants also produce very large quantities of liquid and solid wastes and emit significant quantity of radioactivity. Due to presence of radionuclides in coal and uncontrolled radioactivity releases, some of the coal fired power plants release more radioactivity than nuclear power plants (see Figure 8.1).

8.3.2. Hydro Power

Although no atmospheric pollution is caused by hydroelectric generation, other environmental damages may be very severe in some of the cases. Dams and lakes have both local and downstream effects by virtue of their impacts on hydraulic regime of watercourse: silting, non-release of soil nutrients, waterlogging of the surrounding area, effect of flood irrigation agriculture and mangrove forests, seismic impacts, spread of water borne diseases, submergence of large area, deforestation, erosion of coastal lands, etc. However, the most important impact of hydroelectric projects, with large reservoirs, is the socio-cultural problem of resettlement of the people.

8.3.3. Nuclear Power

Nuclear power plants do not produce gases such as CO_2, SO_2 and NO_x, which are responsible for acid rain and global warming. Although, some radioactive materials are released to the environment during normal operation of nuclear power plants and other nuclear fuel cycle facilities, the amounts released are very small and strictly kept within the permissible limits laid down by international organizations (ICRP and IAEA) to ensure safety of public and the environment. In fact, the amount of radioactivity released from normal operation of a nuclear power plant in some cases is smaller than that from other sources of electricity.



Source: [91]

FIG. 8.1. Estimated Collective Dose Commitments of General Public due to Systems of Electricity Production (Normalized)

Figure 8.1 compares the estimated collective dose commitments of general public for one gigawatt-year of electricity generation from power plants based on nuclear, coal, oil, natural gas and some other sources. It is seen that the radiation dose received by the general public from coal fired power plants is significantly larger than that from nuclear power plants for the same amount of electricity generation while those from geothermal and peat based power plants are of the same order. The underlying reason behind radiation dose from fossil fuel based power plants is that all of the fossil fuels contain some natural radionuclides which are released during their combustion. Further, unlike nuclear power plants, no facility is provided in the fossil fuel plants to contain release of radioactive materials to the environment.

Further, solid wastes generated by nuclear power plants are in very small quantities compared to those from coal fired power plants. This is because the nuclear power plants produce 40 000 kW·h of electricity from each kilogram of natural uranium mined whereas only 2.5 kW·h of electricity can be generated from one kilogram of coal. A 1000 MW nuclear power plant requires only 27 tons of low enriched uranium (requiring the mining of 160 tons of natural uranium) per year, by comparison an equivalent coal fired power plant would need 2.6 million tons of coal per year.

8.4. Environmental Scenarios

Since the objective of the present environmental analysis is to compare alternative plans for future expansion of the power sector in Pakistan, particularly with reference to nuclear power, the power system expansion plans for the Reference case and the nuclear moratorium case, discussed in Chapter 7, have been analyzed from the environmental view point.

It is obvious that the emissions of all air pollutants will be higher in the nuclear moratorium case compared to the Reference Case. As such, another case has been studied in which the capacity mix of nuclear moratorium case has been retained but air pollution control devices have been added to some of the coal and oil fired power plants to bring down the emissions of SO_2, and NO_x, to the levels of the Reference Case.

These three environmental cases are referred to as Case 1, 2 and 3 respectively in the subsequent discussion. The environmental comparison of these three cases will provide insight into the role of nuclear power in avoiding environmental degradation. Further, the analysis will also help to determine cost effectiveness of alternative strategies for avoiding environmental emissions, viz. use of pollution control devices on fossil fuels based power plants vs. use of nuclear power.

8.5. IMPACTS Input Data

For the current study the IMPACTS module of ENPEP has been used to compute environmental burdens resulting from future electricity generation. The IMPACTS input data consist of Fuel Characteristics Data and Power System Data. The preparation of these data are described in the following sections.

8.5.1. Fuel Characteristics Data

The fossil fuel characteristics data, used in IMPACTS database, are as follows:

8.5.1.1. Coal

The present proven coal reserves of Pakistan are spread over 14 fields with bulk of reserves being accounted for by Lakhra, Sonda, Salt Range and Thar (see Table 8.2). These fields have been divided into four categories according to their characteristics and expected future use in electricity generation, while imported coal is considered as a fifth category.

a) **Lakhra field**: The Lakhra coal field, with the largest proven reserves, ranges from lignite A to sub-bituminous C and has high sulphur (1.8 to 6.5%) and high ash (7% to 25%). Three fluidised bed coal fired power plants of 50 MW each, are under construction at Lakhra. It is expected that more capacity will be built on Lakhra coal. In the present study

1000 (10X100) MW future power capacity is considered to be based on Lakhra coal (see Chapter 7).

b) **Thar field**: The recently discovered Thar coal field has large hypothetical resource of some 175 billion tons. The coal in this field is believed to be of lignite category with low sulphur (1.4%) and ash (9.6%). Based on preliminary information, it is expected that some 10–15 GW of electricity generation capacity can be supported by Thar coal field.

c) **Balochistan fields**: This category includes all the coal fields in Balochistan province and quality of these coal is sub-bituminous B to high-volatile B bituminous. Sulphur contents in these fields are 2.6% to 6.5%. Since 1964, a 15 MW coal fired power plant has been working at Quetta using the coal of Balochistan.

d) **Punjab and Sonda fields**: The rank of Punjab coal is high-volatile C to B bituminous. Sulphur contents of Punjab coal fields is 4.8 to 6.7% and ash is 11.2 to 33.4%. Sonda coal is lignite to sub-bituminous C and has 2.7% sulphur and 15.8% ash. At present all the coals of this category are being used in brick kilns and there is no plan for using this category of coal in power sector.

e) **Imported Coal**: Imported coal is also being considered for power generation in Pakistan. The characteristics of imported coal considered in the present analysis are listed in Table 8.2. It has been assumed that good quality steam coal with high heating value and low sulphur content will be imported for power generation.

Table 8.2. Quality and Characteristics of Pakistani Coals

Unit: Weight % except Calorific Value

Coal Field/ Characteristics	**Lakhra**	**Thar**	Sonda	**Balochistan**	Punjab (Except Makarwal)	Makarwal	**Weighted Av.** (Except Thar, Lakhra & Baloch)	**Imported** Coal
Moisture	27 56	46 9	31 15	9 62	7 59	5 54	30 15	10
Volatile Matter	27 93		28 12	40 29	33 39	43 01	28 38	24
Fixed Carbon	25.32		24 96	36 49	34 58	40 25	25 39	
Ash	19 19	9 6	15 77	13 59	24 29	11 19	16 08	16 5
Sulphur	5 49	1 4	2 68	4 99	5 58	5 14	2 80	0 8
Arsenic	0 000293			0 00036	0 0009		0 00090	
Cadmium	0 000016			0 000024	0.00035		0 00035	
Chlorine	0 09909							
Mercury	0 000004							
Lead	0 000971			0 0028				
Calorific Value:								
BTU/lb	6587	5400	6958	9816	9155	11 237	6792	11 250
kcal/kg	3662	3002	3869	5458	5090	6248	3776	6255
gJ/ton	15 33	12 56	16 19	22 85	21 31	26 16	16 00	26 19
Coal Resources*								
(Million Tons)	2464	175 074	5808	196	234	22	6064	

* Measured, Indicated, Inferred and Hypothetical.
Sources: [14, 20 & 92]

Table 8.3. Characteristics of Pakistani Gases

		Balance Recoverable Reserves on 30/6/93 10^{12} ft^3	Heating Value (BTU/ft^3)	Hydrogen Sulphide Grains/ 100 ft^3	Mercaptan Sulphide Grains/ 100 ft^3
	Non-Associated Gas Fields				
1	Mari*	5 089	723	–	–
2	Uch	4 050	450	33 5	10 20
3	Qadirpur	3 979	835	–	–
4	Sui*	3 175	933	92 2	3 80
5	Pirkoh*	1 398	898	–	–
6	Khairpur	1 000	130	2	46 00
7	Kadanwari	0 728	950	–	–
8	Kandkot*	0 653	815	30 8	1 20
9	Dhodak	0 581	–	–	–
10	Ratana	0 350	–	–	–
11	Nandpur	0 296	399	–	–
12	Dakhni*	0 229	–	–	–
13	Loti*	0 216	830	–	–
14	Zin	0 100	–	13 3	2 30
15	Khorewah*	0 100	1112	–	–
16	Adhi*	0 092	–	–	–
17	Jandran	0 082	981	–	–
18	Bukhari*	0 050	1181	–	–
19	Hundi*	0 043	870	21	–
20	Bobi*	0 041	–	–	–
21	Bhatti*	0 035	1132	–	–
22	Panjpir	0 034	397	–	–
23	Turk*	0 032	–	–	–
24	Turk Deep	0 032	–	–	–
25	Nakurji	0 026	–	–	–
26	Sari*	0 025	903	28	–
27	Matli*	0 020	1018	–	–
28	Mukhdumpur*	0 019	1141	–	–
29	Golarchi*	0 019	1033	–	–
30	Mazarani	0 019	976	10 7	2 20
31	Koli	0 015	1037	–	–
32	Mahi	0 013	–	–	–
33	Daru	0 013	1215	–	–
34	Rodho	0 013	1111	–	–
35	Dhabi*	0 013	–	–	–
36	Kothar*	0 012	870	–	–
37	Sonro*	0 011	903	–	–
38	Buzdar	0 008	–	–	–
39	Nur	0 006	–	–	–
40	Kato	0 005	1236	–	–
41	Tando Ghulam Ali	0 004	964	–	–
42	Dabhi South	0 004	1140	–	–
43	Jabo	0 003	980	–	–
44	Bhal Syedan*	0 003	–	–	–
45	Nari*	0 002	–	–	–
46	Halipota*	0 002	–	–	–
47	Rind	0 002	–	–	–
48	Pir	0 001	1057	–	–
	Associated Gases	0 181	1100	–	–
	Total	22 820	724	–	–
Average weighted by their reserves		(0 646 trillion m^3)	(26 96mJ/m^3)		
Average H_2S (grams/100 ft^3)				3 250 (1 148 gm/m^3)	
(Weight %)				0 139	
Sulphur (Weight %)				0 131 **	

1 gram = 15 4 grains

* In production

** During gas processing, almost all the sulphur is taken out and power plants are supplied gas with negligible sulphur

Sources [14, 16 & 17]

8.5.1.2. Natural gas

As shown in Table 8.3, there are large variations in the heating values and chemical contents of the 48 natural gas fields discovered in the country. The major gas fields are Sui, Mari, Pirkoh, Qadirpur and Uch. In order of present level of production, the important fields are Sui, Mari, Pirkoh, Khandkot and Bukhari. The average heating value of indigenous raw gas is 27 million J/m^3 while the average sulphur content is 0.13% by weight. During the gas processing steps almost all the sulphur is removed and power plants are supplied with gas of negligible sulphur content.

The Government of Pakistan is planning to import natural gas from neighboring countries (Islamic Republic of Iran, Qatar and Turkmenistan). It is hoped that imported gas will be available in Pakistan by the turn of this century. The characteristics of indigenous gas have been used for imported gas owing to non-availability of imported gas data.

8.5.1.3. Petroleum products

The characteristics of petroleum products, used in power sector of Pakistan, are listed in Table 8.4. Presently, High Sulphur Furnace Oil (HSFO) of 3.5% sulphur content and High Speed Diesel (HSD) with 1% sulphur are being used in power plants for electricity generation. However, low sulphur furnace oil with 1% sulphur is also being considered as future option for power generation.

Table 8.4. Characteristics of Petroleum Products being used in Pakistan

	Heating Value		Contents (Weight %)	
Product	GJ/Ton	GJ/BBL	Sulphur	Ash
High Speed Diesel	46.5	6.21	1.0	0.01
High Sulphur Furnace Oil	43.0	6.16	3.5	
Low Sulphur Furnace Oil	43.0	6.16	1.0	

Sources [14 & 20]

8.5.2. Power System Data

8.5.2.1. Technical and economic data

The technical and economic parameters of existing and future power plants, used as the input of ELECTRIC module (discussed in Chapter 7) have been used for IMPACTS module's application. In addition, the data on capital cost and operation cost for control devices have been prepared from various sources [93 & 94]. All this information is reported in Tables 8.5 and 8.6.

8.5.2.2. Emission factors

Due to their importance for local, regional and global environmental impacts, four major atmospheric pollutants have been considered for environmental analysis, namely: Particulates, Sulphur dioxide (SO_2), Nitrogen oxides (NO_x), and Carbon dioxide (CO_2). Particulates (dust) begets environmental concerns to the local population; SO_2 and NO_x are responsible for regional problem of acid rain; and CO_2 is likely to cause global warming through greenhouse effect. In addition to liquid and solid wastes, radioactive emissions have also been considered. Emissions of other pollutants, e.g. Carbon mono-oxide, Non-methane volatile organic compounds (NMVOC), Hydrocarbons, etc., have not been computed due to their smaller quantities and unknown impacts.

Table 8.5. Techno-economic Data of Candidate Thermal Power Plants

Plant	FOL6	COAL	DCOL	CCIG	GTIG	NUCL
Capacity (MW)	600	600	100	450	100	600
Efficiency (%)	34.1	33.8	32.0	41.4	27.3	34.8
Capital Cost (excluding IDC*)						
$/kW	975	1130	1608	761	512	1700
$/GJ	10.53	12.10	16.30	9.98	4.43	18.76
O & M Cost						
Fixed($/kWmonth)	1.33	1.25	3.00	0.58	1.00	2.50
Variable($/MW/h)	1.70	2.10	4.00	3.00	4.20	0.50
Total O & M($/GJ)	0.979	1.059	2.254	1.054	1.547	1.091
Construction Time (year)	4	5	4	3	2	6
Interest Rate (%)	10	10	10	10	10	10
Life (year)	30	30	30	25	20	30

* IDC: Interest During Construction
Note: All costs are in 1993 US dollars

Table 8.6. Techno-economic Parameters of Pollution Control Devices

Control Device	Plant Size (MW)	Capital Cost ($/kW)	Capital Cost ($/GJ)	Operation Cost (mill/kW·h)	Operation Cost ($/GJ)	Removal Efficiency
Flue Gas desulphurisation	600	263	2.8171	4.41	0.4135	90% of SO_2
Selective Catalytic Reduction	600	123	1.3175	3.27	0.3070	80% of NO_X

Note: All costs are in 1993 US dollars
Source: Based on [93 & 94]

Most of the emission factors (particulates, SO_2, CO_2 and solid wastes) for all the existing and future power plants have been computed on the basis of the technical parameters of power plants and the characteristics of fuels used by these plants. However, in some cases (NO_x, liquid waste), due to lack of specific data, generic data have been used from the IMPACTS database and other sources. The emission factors for nuclear power plants have been computed from actual historical releases of radioactivity in the case of Karachi Nuclear Power Plant and from the estimates for such releases from Chashma Nuclear Power Plant in the case of future nuclear power plants [89 & 95]. All these emission factors are listed in Table 8.7.

In the case of hydropower plants, the cost for resettlement of people and that for the land submerged are already included in the capital cost of these plants. As such, no environmental impact of hydropower plants has been included in the comparison.

Table 8.7. Emission Factors

A: Fossil Fuel Fired Power Plants

Air Emissions (kg/gJ)

Type of Plant	Fuel	SO_2	NO_X	Particulate	CO_2
Combustion Turbines	Gas	0.0002	0.1760	0 0068	69.63
Combined Cycle	Gas	0.0002	0.1736	0.0069	68.87
Steam	Gas	0.0002	0.1724	0.0067	68.20
	HSFO	1.6424	0.3113	0.0297	74.62
Steam without FGD	Thar/ Imported Coal	0.5506	0.3405	1.2618	83.28
FBC	Lakhra Coal	1.0175	0.0622	0.1546	86.07
Quetta Steam	Balochistan Coal	3.9362	0.3404	1.1911	92.45

Liquid and Solid Wastes

Type of Plant	Fuel	Liquid Wastes (kg/m^3)		Solid Wastes (kg/gJ)
		TSS	TDS	
Combustion Turbines	Gas	0.22	0.208	
Combined Cycle	Gas	0.22	0.208	
Steam	Gas	0.22	0.208	
	HSFO	0.22	0.208	
Steam without FGD	Thar/ Imported Coal	0.03	0.000	5.05
FBC	Lakhra Coal	0.03	0.000	417.48
Quetta Steam	Balochistan Coal	0.03	0.000	4.76

B: Nuclear Power Plants (10^{12}Bq/gWyr)

Type of Plant	Air				Water		
	Kr-85	Xe-133	H-3	I-131	CO-60	CS-137	H-3
LWR	72	180	28	0.0042	0.003	0.0123	62
KANUPP			3540	1.7			2783

FBC fluidized Bed Combustion

FGD Flue Gas Desulphurisation

TSS Total Suspended Solids

TDS Total Dissolved Solids

Sources: Based on [20, 89, 90 & 95]

8.6. Application of IMPACTS Module

8.6.1. Data Import from ELECTRIC Module of ENPEP

For application of the IMPACTS module, some data are imported from the ELECTRIC module of ENPEP (WASP) contained in three output files ELIM1.DAT, ELIM2.DAT and ELIM3.DAT. The first two files are created by the REPROBAT sub-module of ELECTRIC while the third is created by the REMERSIM sub-module. IMPACTS can only import power system expansion plans from ELECTRIC if all the three files are present in the Planning Study sub-directory. The version of the ELECTRIC module available during the conduct of the study does not create ELIM3.DAT file during its execution. A small computer program, in FORTRAN language, has been developed to create the ELIM3.DAT file. This computer program extracts the ELIM3.DAT file from MERSIM1.REP file of ELECTRIC module. The program listing is attached as Table 8.8.

8.6.2. Assignments to Fuels and Power Plants

To apply the IMPACTS module, a unique IMPACTS label is required to be assigned to each fuel and power plant considered in the analysis. Three types of fossil fuels are being used in Pakistan for electricity generation. They are: Coal, Natural gas and Petroleum products (Furnace Oil and High Speed Diesel Oil). Assignments of IMPACTS labels made to fossil fuels, used in the present analysis are listed in Table 8.9.

The power system of Pakistan has been represented in the ELECTRIC module of ENPEP by 35 (28 existing/committed and 7 candidate) types of thermal power plants and two types of hydro plants. These plants have been represented in the Facility database of IMPACTS module by assigning IMPACTS labels to each of these plants. In the process of assignment, grouping of various power plants have been made to keep the problem at reasonable size. The principal yardstick in group forming is electricity generation capacity of the power plants. As this analysis does not include impacts of hydro power plants, they have been ignored in the assignment process. The complete list of these assignments is given as Table 8.10.

8.6.3. Selection of Control Devices

Pollution control devices have been considered in the present analysis only for particulates, SO_2 and NO_x emissions, since no data are available (even in IMPACTS generic database) for liquid and solid wastes control devices.

For particulates control, Fabric Filters have been considered for all coal fired power plants and their costs have been included in the power plant costs. For SO_2 emission control, flue gas desulphurisation (FGD) technology, and for NO_x emissions control, Selective Catalytic Reduction (SCR) system, have been added to some of the coal and oil fired power plants in Case-3. Presently, almost all the installed FGD systems in the world use lime or limestone as a reagent and have removal efficiency of about 90–95%. The NO_x removal efficiency of SCR system depends on input and output concentration of NO_x, temperature of the flue gas, NH_3/NO_x ratio, capacity of the catalyst and the SO_3 concentration. Most SCR systems, installed in the world, have removal efficiency of 80%. Other control devices are also available for SO_2 and NO_x removal but FGD and SCR have been considered owing to relatively higher efficiencies and wide spread use in the power industry.

Table 8.8. FORTRAN Listing of Computer Program Developed to Prepare ELIM3.DAT" required as input for IMPACTS Module

```
C  Developed by "Applied Systems Analysis Group, PAEC"
C  to Prepare "ELIM3.DAT" for IMPACTS Module
C  Input File used is "MERSIM1.REP"
C
   program impdata
   dimension hyc(4)
   character pname*4,a*1
   ny=30
   npr=6
   nh=3
   npl=36
   hyc(1)=0.3
   hyc(2)=0 4
   hyc(3)=0.3
 5 read(2,100)a
   if (a.eq.1.or.a.eq.char(10)) go to 5
 6 read(2,200)pname
   if (pname.ne."hyd2") go to 6
   do 40 i=1,ny
   do 30 j=1,npr
   do 20 k=1,nh
   read (2,400)gen
   write (3,500) gen*hyc(k)
   do 10 l=1,npl-1
   read (2,300)gen
   write (3,500) gen*hyc(k)
10 continue
   if ((i.eq.ny).and.(j.eq.npr).and.(k eq.nh)) go to 15
 3 read(2,100)a
   if (a.eq.1.or.a.eq.char(10)) go to 3
 4 read(2,200)pname
   if (pname.ne "hyd2") go to 4
20 continue
30 continue
40 continue
100 format(a1)
200 format(8x,a4)
300 format(56x,f9.1)
400 format(//////56x,f9.1)
500 format(2f9.1)
   stop
15 end
```

Table 8.9. Assignments to Fossil Fuels Used in Power Sector of Pakistan

		Fuel Type	Fuel No
Coal	Lakhra Field	COP	1
	Thar Field	COP	2
	Baluchistan Fields	COP	3
	Punjab and Sonda Fields	COP	4
	Imported	CBI	5
Oil	High Speed Diesel Oil	PP3	5
	High Sulphur Furnace Oil	PP4	5
Gas	Average Pakistani Natural Gas	GAS	3

Table 8.10. Assignments to Electricity Generation Technologies

IMPACTS	Facility			IMPACTS	Facility		
No.	Name	Type	No	No.	Name	Type	No.
1	MULT	EGT	2	19	KTP1	EGT	2
2	FDST	EGT	2	20	KAC2	EGT	5
3	GU12	EGT	3	21	KAGT	EGG	8
4	GU34	EGT	8	22	KAC3	EGT	5
5	STM1	EGT	2	23	GCC2	EGT	6
6	QTST	ECP	3	24	MUZ2	EOT	3
7	GUCC	EGT	5	25	CHNU	ENB	4
8	KACC	EGT	5	26	HUB	EOT	3
9	FDCC	EGT	4	27	JOF3	EOT	3
10	KOCC	EGT	4	28	KANP	ENB	5
11	JOF1	EOT	2	38	FOL3	EOT	3
12	JOF2	EOT	2	39	FOL6	EOT	4
13	MUZ1	EOT	2	40	COAL	ECT	4
14	GTG1	EGG	8	42	DCOL	ECA	4
15	GTG2	EGG	8	43	CCIG	EGT	7
16	KTP2	EGT	3	44	GTIG	EGG	9
17	BQSM	EOT	2	45	NUCL	ENB	6
18	LFBC	ECA	3				

Table 8.11. Estimated Annual Environmental Emissions from Electricity Generation in Pakistan

	1993	2003			2013			2022		
		Case-1	Case-2	Case-3	Case-1	Case-2	Case-3	Case-1	Case-2	Case-3
SO_2 (10^3 tons)	210	433	458	436	636	1215	634	2014	3600	2025
NO_x (10^3 tons)	80	150	165	153	327	439	334	862	1161	867
CO_2 (10^6 tons)	26	48	51	51	103	133	133	250	322	322
Particulates(10^3 tons)	6	10	10	10	13	23	23	34	63	63
Solid Waste(10^6 tons)	0 004	13	13	13	27	36	37	38	43	46
Liquid Wastes (10^3 tons)										
Total Suspended Solids	22	36	38	38	68	91	91	155	212	212
Total Dissolved Solids	20	32	32	32	55	75	75	118	171	171
Radioactivity (10^{12} Becquerel)	303	556	374	374	1561	90	90	686	90	90

Case 1: Reference Case

Case 2: Nuclear Moratorium Case

Case 3: Case 2 with SO_2 and NO_x Control Devices

8.7. Comparison of Alternative Electricity Generation Expansion Plans

8.7.1. Environmental Emissions

Table 8.11 gives the annual environmental emissions from power generation in the years 1993, 2003, 2013 and 2022, in the three cases. It may be noted that the annual emissions of SO_2, NO_x, and CO_2, in Case-1, increase by a factor of about 10 over the study period, while these emissions in Case-2 increase by factors 13–18 over the same period. In the year 2022 the SO_2 and NO_x emissions, which give rise to acid rain, are 35–78% higher in Case-2 compared to Case-1, while the CO_2 emissions are about 29% higher. Other environmental burdens, particulates and solid waste which are important for local environment only, are also higher by about 13–85% in Case-2 compared to Case-1. The radioactive emissions have been worked out for nuclear power plants only whereas such emissions from fossil fuel plants are believed to be significant, but could not be estimated due to lack of necessary information. The Case-1 has higher radioactive emissions compared to Case-2, but these emissions from nuclear power plants are strictly kept within permissible limits.

Radioactive elements naturally occurring in fossil fuels, especially in coal are released unchecked by fossil fueled power plants. Such releases could not be estimated due to lack of reliable data.

As for Case-3, the emissions of SO_2 and NO_X are at the same level as those in Case-1, but the emissions of CO_2 are 29% higher compared to Case-1. The amount of solid waste is also about 21% higher in Case-3 compared to Case-1. It is therefore clear that the power system expansion plan in Case-1 is considerably superior to those in Case-2 and Case-3 from an environmental point of view.

Table 8.12. Cumulative Investment and Operation Costs (1993–2022)

Million US $ of 1993

	Case-1	Case-2	Case-3
Investments	108 021	93 450	102 513
Operation Costs	171 764	204 702	212 704
Total	279 785	298 152	315 217

Case 1: Reference Case
Case 2: Nuclear Moratorium Case
Case 3: Case 2 with SO_2 and NO_x Control Devices

8.7.2. Investments and Operation Costs

Table 8.12 gives total investments and system operation costs (O & M plus fuel costs) over the 30 year period for the three cases. The total investments in Case-1 are higher by US$15 billion compared to those in Case-2, because of nuclear power plants included in Case-1 which have relatively higher capital cost compared to fossil fuel based power plants. However, the system operation cost in Case-1 is lower by US$33 billion due to much lower fueling costs of nuclear power plants. The total of investments and operation costs is thus lower by US$18 billion in Case-1 compared to that for Case-2.

The total investments in Case-3 are US$102.5 billion which are higher by US$9.1 billion compared to Case-2. Although the power capacity mix in Case-3 is the same as in Case-2, the additional investments in Case-3 are because of investments on pollution control devices added to some of the fossil fuel based power plants. The cumulative system operation cost over the 30 year period in Case-3 is also higher by US$8.0 billion compared to that in Case-2. Compared to Case-1, the total investments in Case-3 are somewhat lower but the system operation cost in this case is considerably higher than that in Case-1, making the overall costs (investments and operation costs) much higher compared to those in both the cases (i.e. Case-1 and Case-2).

8.7.3. Cost Effectiveness Analysis

There is no universally accepted methodology available for assessment of cost effectiveness of alternative strategies for reduction of environmental emissions from electricity sector. In general, incremental cost of reducing environmental emissions is used as an indicator to rank different alternatives. However, working out incremental cost poses some conceptual and practical problems. This is particularly true when alternative plans for expansion of electric systems are to be compared. The main difficulties arise from the followings:

- The additional costs for reduction of environmental emissions and the benefits in terms of reduced emissions have inter-temporal effects. Even if discounted costs and benefits are used for calculating leveled incremental cost of reducing environmental emissions, discounting over the planning period would result in under-estimation of the benefits, because, the investments made towards the end of the planning horizon will also provide benefits in the post planning horizon period. It, therefore, seems necessary to account for benefits accruing in the post planning horizon period.

- Adoption of a certain measure for reduction of environmental emissions may also result in reduced emissions of more than one type of pollutants. For example, if coal fired power plants are replaced by nuclear power plants in an alternative expansion plan, the emissions of SO_2, NO_X, CO_2 etc., will all be reduced. In this case, it is difficult to allocate additional cost to benefits from reduction of different pollutants. Proper weighting of various pollutants based on their damaging impacts may be done to assess overall cost effectiveness of that strategy.

In the present analysis, an attempt has been made for the assessment of cost effectiveness of alternative strategies for reduction of environmental emissions using leveled incremental cost of reducing environmental emissions ($ per ton of pollutant removed). The leveled incremental cost has been calculated by two methods, viz.

- considering the present worth of the additional costs and benefits over the planning horizon by discounting the two at 10% p.a. discount rate, and

- considering discounted additional costs and benefits over the planning horizon as well as in the post planning horizon period.

The reduction in emissions of SO_2 and NO_x have simply been added, because for simplicity these two pollutants have been assumed to have about the same impact in terms of acidification, while any benefits in terms of reduction in emissions of CO_2 and other pollutants have been considered as a bonus.

To account for the costs and benefits in the post planning horizon period, it has been assumed that after the year 2022 the electricity demand and power system capacity will remain the same as in 2022. Any power plant retiring after 2022 will be replaced by an identical plant. Hence, the annual environmental emissions and the annual system operation cost will remain constant after 2022. The investment in the post-2022 period will be only for replacement of retiring plants.

Table 8.13 shows incremental cost of reducing SO_2 and NO_x emissions in Case-1 and Case-3 with respect to Case-2. The leveled incremental cost for both the cases (Case-1 and Case-3) decreases with extending the period beyond planning horizon. This impact is more pronounced in Case-1, because additional investments are more dominating in this case due to higher investments on nuclear power plants. However, this impact saturates after 20–25 years beyond planning horizon. For practical purposes, a period of 10–15 years beyond the planning horizon would be sufficient to account for inter-temporal impacts of additional costs and benefits, if a high value for discount rate is used, while calculating incremental cost of reducing environmental emissions. As shown in Table 8.13, the incremental cost due to additional investments for reducing SO_2 and NO_x emissions is much larger in Case-1 compared to that in Case-3, but that due to additional operation cost is negative in Case-1, making the overall incremental cost much lower in Case-1 compared to that in Case-3. The above analysis has shown that on the basis of incremental cost of reducing environmental emissions the strategy of using nuclear power plants in place of fossil fuel based power plants is superior to the strategy of using pollution control devices.

Table 8.13. Incremental Cost of $SO_2 + NO_X$ Reduction # (US $ per Ton of $SO_2 + NO_X$)

	Investment Cost		System Operation Cost		Total Cost	
	Case-1	Case-3	Case-1	Case-3	Case-1	Case-3
Leveled* Incremental Cost over the 30 Years	1875	776	–2466	590	–590	1367
Leveled* Incremental Cost over the 40 Years	1296	531	–2423	583	–1127	1114
Leveled* Incremental Cost over the 50 Years	1198	489	–2413	582	–1215	1071

Based on additional costs and reduced emissions of SO_2 and NO_x with respect to Case-2.

* Using discount rate of 10% p.a.

Case 1: Reference Case

Case 2: Nuclear Moratorium Case

Case 3: Case 2 with SO_2 and NO_X Control Devices

8.8. Conclusions

On the basis of the preceding analysis, it is observed that the power system expansion plan worked out in the Case-1 (Reference Case) is much better from environmental view point compared to that in the Case-2 (nuclear moratorium case). The later gives rise to very high emissions of SO_2, NO_x and CO_2 than those corresponding to the former. Besides large atmospheric emissions of pollutants, the expansion plan in Case-2 also results in productions of very large quantities of liquid and solid wastes. As for radioactive emissions from nuclear power plants, such emissions are obviously higher for the Case-1 but these are strictly controlled and contained within permissible limits. Radioactive emissions from fossil fuel based power plants, though not worked out in the present analysis due to lack of data, may be quite significant.

Due to limited indigenous energy resources, future electricity generation will require the use of all available technological options. Whatever the power system expansion plan is adopted, the environmental emissions will increase by an order of magnitude over the whole study period. However, the use of nuclear power can significantly help to reduce the future environmental emissions of SO_2, NO_x, CO_2, solid wastes and other pollutants, while not causing any serious threat to the environment owing to radioactivity releases.

Nuclear power requires somewhat higher investments than fossil fuel fired power plants, however, the gap becomes trivial when fossil fuel fired power plants are equipped with SO_2 and NO_x emission control devices. Further, the use of nuclear power becomes economically attractive when the total system costs are considered. It is thus clear that the increased use of nuclear technology for electricity generation in Pakistan in the coming decades will not only be helpful in reducing the environmental degradation owing to future electricity generation in Pakistan, it will also be cost effective. On the basis of the foregoing analysis it can be concluded that the maximum feasible use of nuclear power for future power generation is required when environment matters.

Chapter 9

FINANCIAL ASSESSMENT OF NUCLEAR POWER EXPANSION PLAN

9.1. Introduction

The Pakistan Atomic Energy Commission is responsible for development, operation and safety of nuclear power plants in the country. The Karachi Nuclear Power Plant, KANUPP, is being operated by PAEC since 1971. The electricity generated from KANUPP is sold to Karachi Electric Supply Cooperation at an agreed tariff. The plant is being operated on self-finance basis without any budgetary support from PAEC or the government, and is making considerable profits. The second nuclear power plant, CHASNUPP, of 300 MW capacity is under construction and will also be operated on self-reliance basis. As for future nuclear power plants, for the present study, it has been assumed that a nuclear power company will be established in the public sector (under PAEC umbrella), which will own and operate nuclear power plants. The company will raise equity from shareholders (may be from the government alone) and will arrange loans from local and foreign sources (with or without government guarantees) to finance its investments. This arrangement has been assumed to analyse the financial viability of nuclear power development plan.

The reference case of power system expansion plan, described and discussed in Chapter 7, represents the least-cost development plan which will meet projected electricity demand within the confines of assumed technical and physical constraints. This plan suggests development of about 84 000 MW of power generation capacity during the period of 1997–2022. Nuclear power generation is an important component of this least-cost expansion plan. Of the envisaged total capacity expansion, 13 500 MW is based on nuclear power. A total of 22 nuclear power plants, 600 MW capacity of each, appear in the least cost plan. The construction of these 22 nuclear power plants will require an investment of US $22.4 billion, in terms of 1993 prices, including about 70% in foreign exchange. Financing of this investment may be a major constraint to the implementation of the plan. In order to analyse financial viability of the nuclear power investment programme, a detailed financial analysis has been carried out. This chapter describe the main assumptions and the results of the financial analysis of the nuclear power development plan.

9.2. Methodology

The financial analysis of the investment programme of the nuclear power company has been carried out using the FINPLAN model developed by the IAEA. The FINPLAN model includes five modules: (1) investment module, (2) debt module, (3) revenue and expenditure module, (4) tax and royalty module, and (5) foreign exchange module. The *investment module* calculates cash flows associated with the ongoing and committed investment plan, plus the additional investments in generation, transmission and distribution assets associated with the proposed expansion plan. The *debt module* computes cash flows associated with the financing of new assets including borrowing, interest payments and loan repayments. In addition, it calculates the net loans outstanding. The *revenue and expenditure module* computes cash flows of revenues and expenditures, the latter includes operation and maintenance (O&M) costs and dividend payments. In addition, the module computes depreciation charges on new assets. The *tax and royalty module* computes cash flows on royalties, income tax and equity repayments. The *foreign exchange module* computes foreign currency requirements for investment, purchase of imported fuel and debt services on foreign loans considering drawdowns of foreign bonds and foreign cash balance. As a result of the analysis, the FINPLAN model generates Balance Sheet, Statement of Sources and Applications of Funds and a number of Financial Ratios for each year of the planning period. These ratios are used to infer financial viability of the proposed investment programme only on technical basis. However, there are many other considerations (such as political) which may, in some cases, be more important in establishing financial viability of an investment programme.

In order to carry out detailed financial analysis of the proposed long term nuclear power programme on individual plant basis, the FINPLAN model has been modified for its present application. The model has been split into two parts. The first part consists of modules 1 to 3, mentioned above, which have been used on individual project basis. In addition, in this part, cash flows of all projects have been aggregated for each module. The second part uses all the five modules, with aggregated values of modules 1 to 3 transferred to it from the first part, and prepares Balance Sheet, Statement of Sources and Applications of Funds and Financial Ratios.

Two further modifications have been made in the FINPLAN model, viz. change in computation of dividend payments and introduction of self-financing. Normally dividend payments are made from the total net income of a company, but in the modified income and expenditure module the net operating income[1] of each plant has been computed on project basis, and dividend is paid on equity raised for a particular plant. The investment module has been modified to accommodate self-financing. The internally generated funds[2] of the company have been assumed to be invested in its future projects.

In the application of the FINPLAN model in this study, there were no previous debts or existing debt service as the nuclear power company is assumed to be newly established. Starting from 1997, the financial programme has been extended through to the year 2022. The model prepared Balance Sheet, Statement of Sources and Applications of Funds and Financial Ratios for the entire period (1997–2022) based on proposed investment programme, terms of financing, expected revenues and other assumptions.

9.3. Main Assumptions and Input Data

9.3.1. Investment Programme and Investment Costs

The envisaged nuclear power development programme analysed here is a part of the least-cost expansion plan of the power sector for the Reference Case for the period 1994–2022, which has been described in Chapter 7. A total of 22 new nuclear power plants of 600 MW each appear in the least-cost plan. The plan gives the schedule of construction of these plants. Each plant has been assumed to take 6 years for construction. Construction of the first of these plants will start in 1997, and it will become operational in 2003. There is one addition every second year till 2007, one every year during 2008–2018 and two every year after 2018. The overall schedule for construction and operation of plants is shown in Fig. 9.1.

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[1] Net operating income of the company refers to revenues net of total operating costs and debt service payment.

[2] The internally generated funds refer to net operating income less of dividends.

Year	1997		1999		2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021	2022
No. of Plants in Operation							1	1	2	2	3	4	5	6	7	8	9	10	11	12	13	14	16	18	20	22
No. of Plants under Construction	1	1	2	2	3	4	4	5	5	6	6	6	6	6	6	6	7	8	9	10	9	8	6	4	2	

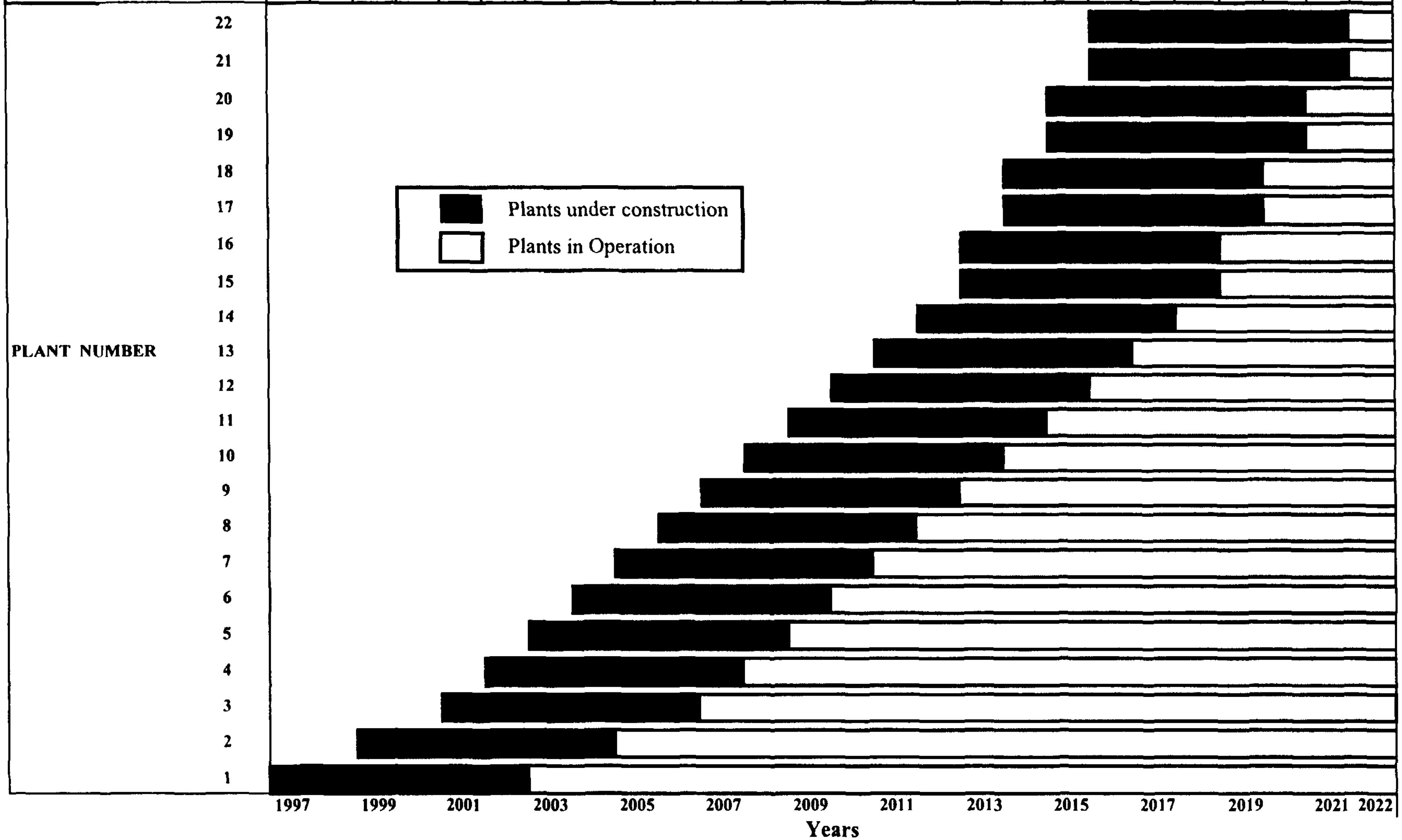

FIG. 9.1. Nuclear Power Expansion Plan: Reference Case From WASP Study

Table 9.1. Investment Cost of a 600 MW Nuclear Power Plant (Constant Prices of 1993)

Investment Costs	Foreign Component (US $ Million)	Local Component (US $ Million)	Total Cost (US $ Million)
1st year	20.1	8.6	28.7
2nd year	49.9	21.4	71.3
3rd year	154.1	66.0	220.1
4th year	264.3	113.3	377.6
5th year	176.4	75.6	252.0
6th year	49.2	21.1	70.3
`Total Investment Costs	714.0	306.0	1020.0

The specific investment cost for each nuclear power plant has been assumed as US $1700/kW in terms of 1993 prices which translates to US $1020 million for the capital cost (without IDC) for each plant. The foreign and local components of this cost, together with their distribution over 6 year construction period are given in Table 9.1. These costs figures exclude any duties, taxes, or subsides. The basis of these cost estimates are discussed in detail in Chapter 7. The foreign and local distribution of the investment cost for the first plant has been assumed as 71:29. Although the local costs component is expected to increase overtime due to indigenization of nuclear power plants, it has been assumed that the foreign and local distribution of the investment cost will remain constant for all the plants.

The foreign component of the investment costs (at 1993 prices) has been converted into nominal dollars of the construction year of a plant using the foreign inflation index, while local component has been first converted into 1993 Rupees values and then escalated with the local inflation index.

9.3.2. Inflation Rates

Local inflation in Pakistan has been around 9% p.a. during the last 13 years [10]. The 8th Five Year Plan and the Perspective Plan assume 6.5% inflation for the period 1998–2003. In all the previous planning studies, the local inflation rate has been assumed in line with the government's estimate. In the present analysis, it has been assumed that the local inflation rate will come down from 13% in 1994 to 8.0% per annum in 1996 and thereafter decline gradually to a level of 6.5% per annum till 2000. For the remaining study period, the local inflation rate has been kept constant at 6.5% per annum. These values are also in line with the projections for Pakistan's GDP deflator assumed in a recent study on energy sector conducted by the World Bank [88].

Foreign currency inflation has been assumed to be 3.5% per annum for the entire study period in line with the World Bank forecasts for the Manufacturers Unit Value Index [20].

9.3.3. Exchange Rate

The future exchange rate has been worked out on the basis of the differential between the assumed local and foreign inflation rates. Since inflation index for foreign currency (US dollar) is projected to be lower than that for local currency, the exchange rate between Rupee and dollar will gradually deteriorate over the study period. One US dollar, which is equivalent to Rs. 25.96 in the base year (1993), will become equivalent to Rs. 70.74 in the year 2022.

9.3.3. Operating Costs

Operating costs comprise fuel costs and Operation and Maintenance (O&M) costs. The fuel has been assumed to be supplied from abroad, while goods and services for O&M are assumed to be supplied locally. Therefore, the fuel cost is expressed in foreign currency and has been assumed as US 20.3 million dollars per year per plant in 1993 prices, and the O&M cost expressed in local currency has been taken as US 20.1 million dollars per year per plant in 1993 prices (see Chapter 7 for details). The fuel cost has been escalated with foreign inflation index, while the O&M cost has been escalated with local inflation index.

9.3.4. Bulk Tariff Rate

The government of Pakistan has set the bulk tariff rate for private power generation as US cents 5.91 per kW.h [96] as the levelized tariff for the entire operational life of a power plant. However, the policy allows a higher tariff (6.5 cents/kW.h) for the initial ten years of plant operation to facilitate debt servicing. In the present study, for computational convenience, the levelized tariff rate has been assumed for the entire operation period of all the nuclear power plants. This bulk tariff was converted into 1993 Pak. Rupees, and escalated at the local inflation rates to arrive at the tariff rates in the generation years for a power plant. These tariff rates in nominal terms are used to compute the revenues from electricity sales on project basis.

9.3.5. Depreciation of Plants

A variety of methods are available for working out depreciation. Each depreciation method has unique features, and the choice of a particular method is often influenced by factors such as income tax laws and regulations. According to regulations of the government of Pakistan, the two power utilities in the country use the straight line method for depreciation. The same method has been used for the nuclear power company in this study. The economic life of each nuclear plant has been assumed to be 24 years for the purpose of calculating depreciation.

9.3.6. Interest During Construction (IDC)

Generally the interest on loans, during the construction period of a project is paid from a company's own resources. However, in some cases the commercial banks permit capitalization of IDC, i.e. accumulation of IDC and its addition to the loan amount, only for 2 to 3 years. Since the construction period of nuclear power plants is quite long, i.e. six years, the IDC has not been capitalized in the present analysis. It has been assumed that the company either raises equity equivalent to the IDC due on loans for a project on annual basis or pays this interest amount from internally generated funds of the company, i.e. net earnings from the operational plants. This assumption has been made for all loans except Export Credit-I as discussed in Section 9.3.9. All loans have been assumed to be project specific and IDC has been computed for each loan separately at the rate assumed for the repayment of that type of loan. These interest rates are discussed in Section 9.3.9.

9.3.7. Fiscal Variables

The power utilities are exempted from income tax and corporate tax in the fiscal policy of the government of Pakistan. Further, all equipment and fuel imported for nuclear power generation are also exempted from import duties. Accordingly, it has been assumed that the company does not pay any income tax, corporate tax and royalties. All goods and services purchased by the company are also assumed to be exempted from the import duties.

9.3.8. Sources of Financing

Of the various possible sources of financing given in the FINPLAN model, the following six sources have been considered in the present case study:

(1) Self-financing
(2) Equity
(3) Local loans
(4) Foreign loan
(5) Export credit 1
(6) Export credit 2

It has been assumed that all equity funds of the nuclear power company will be provided by the Government of Pakistan. All local loans will be borrowed from the local commercial banks, and the foreign loans will be borrowed from foreign commercial banks. Further, it has been assumed that the supplier of a nuclear power plant will arrange export credit I and II from government and commercial banks of its own country.

For the first nuclear power plant, it has been assumed that local and foreign loans will be available for 80% of the total investment, and the remaining 20% will be covered by equity. Furthermore, Export credit I will be arranged by the supplier of the plant to cover 85% of the foreign component of the capital investment. The remaining 15% of the foreign cost component has been assumed to be covered by commercial foreign loans. The local cost component will be covered by equity and local loans. In the present analysis, the local cost is about 29% of the total costs; of this 20 percentage point has been assumed to be met by equity and the remaining by local loans.

Self-financing

As shown in Fig. 9.1, the envisaged nuclear power programme in the Reference case includes commissioning of 22 plants in the span of 25 years starting from 1997. After the completion of the first plant, a part of its revenues can be used for self-financing. This reduces the loan and equity requirements for construction of the 2nd plant. As such, for the remaining 21 plants, the composition of the sources of financing are assumed to be similar to that for the first plant, except that the internally generated funds have been used to meet investment expenditure before exploiting other sources of financing. For example in a year, if the internally generated funds from the previous year are more than 20% of the investment requirement of the plant under construction in that year then equity is not raised and instead these funds are utilized.

In self-financing, the order of priority to reduce loan and equity drawdowns has been assumed as : (i) equity, (ii) local loan, (iii) foreign loan, and (iv) export credit. This utilization priority has been set considering the interest rates and the repayment periods for these sources of financing, and budgetary constraints of the government which has been assumed to provide equity funds.

Table 9.2. Terms of Financing for Loans and Equity

Local loans	
Interest rate	16%
Repayment period	10 years, equal principal payments
Grace period	6 years (construction time for a plant)
Foreign loans	
Interest rate	7 5% p.a
Repayment period	10 years, equal principal payments
Grace period	6 years (construction time for a plant)
Export Credit 1	85% of Foreign cost component
Interest rate	7 5% p.a
Repayment period	18 years, equal principal payments
Grace period	6 years (construction time for a plant)
Export Credit 2	
Interest rate	7.5% p.a
Repayment period	10 years, equal principal payments
Grace period	6 years (construction time for a plant)
Equity capital	20% of the total investments
Dividend rate	15% p.a

9.3.9. Terms of Financing

As mentioned before, it has been assumed that all loans and export credits are on project basis. The terms of financing, i.e. interest rates, repayment period and the grace period, assumed for different sources of financing are summarized in Table 9.2, and are discussed in detail here. In these terms, the major difference is between the terms of financing assumed for the local loans and foreign loans. It has been assumed that the grace period for repayment of all types of loans is 6 years (equal to construction period of a plant).

Local Loans

At the end of December 1994, the weighted-average rates of return on commercial bank advances in Pakistan were in the range of 10%–14% per annum for various types of loans. However, all loans were made to the economic sectors other than the power sector and, therefore, these loans were lent for capital investment in projects of short-term gestation period. As for the power sector, for financing a part of the local portion of project costs, WAPDA in recent years has been issuing bonds carrying returns at 15–18% p.a., with maturity period of 10 years. The Hub power project in private sector has used, for its financial studies, an interest rate of 7–15% on local loans with 10 years repayment time. In the present analysis, the interest rate on local loans has been assumed to be 16% per annum with repayment period of 10 years.

Foreign Loans

As the foreign loans in the present analysis have been assumed to cover the gap between the foreign cost of the project and the export credit available from the supplier, these loans are assumed to be raised from international commercial banks. In the study on the Hub power project in the private sector, interest rate on foreign loans has been assumed as 7.5% with 10 years repayment period.

The government of Pakistan has been on-lending foreign loans to WAPDA and KESC at an interest rate of 11% p.a. which includes exchange risk premium (as the utilities repay the loans in Rupee terms). This rate was raised to 12% in 1994, and the same rate has been assumed for future foreign borrowings of these utilities in their planning studies. Based on these data, the interest rates on foreign loans for the nuclear power company have been assumed as 7.5% per annum (without exchange rate insurance) with the repayment period of 10 years.

Export Credits

Supplier's credit or financing arrangements through commercial banks, guaranteed by export credit agencies, have been widely used by developing countries for financing of power generation systems. Financing of nuclear power plants in a number of countries has been arranged through export credits. The Republic of Korea provides a typical example: Kori unit 1 of 587 MW PWR, with financing of $299 million. China's Guangdong Daya nuclear power project (2x900 MW PWRs, with financing of about $4000 million) is another example of the use of export credits with additional arrangements. German export credit and insurance agencies have provided half of the financing; for the foreign equipment supplies and prices of two nuclear power units (1325 MW of each under construction) in Brazil, while the other half coming from a syndicate of German commercial banks [97]

In Pakistan, export credit arrangements have been made by private sector to finance some of the power projects. In view of the current trends in the world capital market, it has been assumed that 85% of the foreign costs component is supplied under export credit arrangement. The interest rate assumed for the commercial foreign loans has been applied for this credit too, however, the repayment period has been increased to 18 years.

The terms and conditions for export credit 2 (used to pay interest on export credit I during construction period) has been assumed to be similar to that for foreign commercial loans.

Equity

For the financial analysis of the nuclear power company, the rate of dividend on equity has been assumed as 15% per annum. However, the dividend rate has been kept flexible, and it can be less than 15% if the net operating income of the company is insufficient to pay 15% returns on the amount of equity. Since equity fund is raised on project basis, it has been assumed that the company pays dividends from the net earnings of a project before utilizing it for IDC payments or for investment in new plants.

9.4. Financial Plan and Analysis

Using the inputs discussed in Section 9.3, the FINPLAN model was used to carry out financial analysis of the nuclear power expansion plan in the Reference case. Tables 9.3 to 9.8 summarize these results.

Table 9.3. Investment Program and Sources of Financing by Project

Plant Number	Year of Commissioning	Total Investment in Billion Rs.	Share in Total Investment		
			Self Financing	Equity	Loan
(1)	(2)	(3)	(4)	(5)	(6)
1	2003	54.211	0.000	0.220	0.780
2	2005	61.601	0.112	0.135	0.753
3	2007	69.478	0.252	0.124	0.624
4	2008	74.561	0.160	0.153	0.687
5	2009	78.941	0.247	0.124	0.629
6	2010	83.506	0.338	0.125	0.537
7	2011	88.619	0.390	0.125	0.485
8	2012	94.443	0.451	0.064	0.485
9	2013	98.346	0.567	0.055	0.378
10	2014	102.384	0.708	0.056	0.236
11	2015	108.820	0.724	0.056	0.220
12	2016	112.561	0.866	0.017	0.117
13	2017	118.511	0.916	0.017	0.067
14	2018	124.083	0.977	0.005	0.018
15&16	2019	262.268	1.000	0.000	0.000
17&18	2020	279.511	1.000	0.000	0.000
19&20	2021	297.888	1.000	0.000	0.000
21&22	2022	317.473	1.000	0.000	0.000
		2427.206			

Investment Programme

Table 9.3 gives the commissioning year and the capital investment costs in current Pak. Rs., including IDC, of the 22 nuclear power plants. It may be noted that due to inflationary effect in local and foreign currencies the investment costs for construction of a plant in terms of nominal rupees will witness about 3 fold increase by the year 2022. The total investment costs of the expansion programme will be Rs. 2427.2 billion. Table 9.3 also gives the major sources of financing for the 22 plants.

Annual Cash Flow

Annual income of the company will be solely from electricity sales which were computed as the product of the tariff in current prices and units of electricity generated and sold. The latter remains constant for every plant throughout its operational life, while the former increases from Rs. 1.53 per kW.h in 1993 to Rs. 10.68 per kW.h in 2022. The cash flows of the company's revenues will increase from Rs. 13.68 billion in 2003 to Rs. 995.95 billion in 2022 (see Table 9.4) corresponding to the annual sales of 4.23 to 93 TW.h units of electricity in these years. The total operating costs, in the current prices, will increase from Rs. 2.25 billion to 165.68 billion. The operating income, i.e. revenues net of operating costs, of the company will be in the range of Rs. 11.43 billion to Rs. 830.27 billion.

Table 9.4. Annual Income and Operating Costs of the Nuclear Power Company

(Billion Rs.)

Years	Total Revenues	Foreign Fuel Costs	Local O&M Cost	Total Operating Costs	Revenue - Operating Costs
(1)	(2)	(3)	(4)	(5)	(6)
1997	0 00	0 00	0 00	0 00	0 00
1998	0 00	0 00	0 00	0 00	0 00
1999	0 00	0 00	0 00	0 00	0 00
2000	0 00	0 00	0 00	0 00	0 00
2001	0 00	0 00	0 00	0 00	0 00
2002	0 00	0 00	0 00	0 00	0 00
2003	13 68	1 16	1 10	2 25	11 43
2004	14 57	1 23	1 17	2 40	12 17
2005	31 04	2 63	2 49	5 12	25 92
2006	33 06	2 80	2 66	5 45	27 60
2007	52 81	4 48	4 24	8 72	44 09
2008	74 99	6 36	6 02	12 39	62 60
2009	99 82	8 48	8 02	16 50	83 33
2010	127 58	10 85	10 25	21 09	106 48
2011	158 51	13 49	12 73	26 22	132 29
2012	192 93	16 43	15 50	31 93	161 00
2013	231 16	19 71	18 57	38 28	192 88
2014	273 54	23 35	21 97	45 32	228 22
2015	320 45	27 38	25 74	53 12	267 33
2016	372 30	31 84	29 91	61 74	310 56
2017	429 54	36 77	34 50	71 27	358 27
2018	492 66	42 21	39 57	81 79	410 87
2019	599 63	51 43	48 17	99 60	500 03
2020	718 43	61 68	57 71	119 39	599 04
2021	850 15	73 06	68 29	141 35	708 80
2022	995 95	85 68	80 00	165 68	830 27
Total	6082 79	521 00	488 61	1009 61	5073 18

9.4.1. Consolidated and Annual Financial Impacts

The impacts of the nuclear power expansion plan on the finances of the company were examined in terms of total investment cash flows in foreign and local currency, debt service liabilities in local and foreign currencies and total foreign exchange requirement for debt service and O&M costs. These impacts are summarized in Table 9.5 to Table 9.10. Figure 9.2 gives the investment cost, in current prices, over the planning period (1997–2022). Total planned investment including IDC amounts to Rs. 2427.2 billion. The major source of financing will be the company's own resources; contributing about 76% of the total investment (Rs. 1852.6 billion), while the equity contribution will be 4% (Rs. 99.2 billion). The remaining 20% will be borrowed. The total amount of loans will be Rs. 475.2 billion, of which 90% is expected to be from foreign sources, while the remaining 10% (47.5 billion) will be local loans.

Annual Investment Requirements

The annual investment requirement of the company will steadily increase till the year 2018, and will be in the range of Rs. 1.1 billion to 268.9 billion. As shown in Table 9.5, more than half of the total investment of the nuclear power expansion plan will be self-financed. Starting from about Rs. 3 billion in the year 2003; when the first plant becomes operational, the self-financing will rise to Rs. 19.38 billion in 2007. In terms of shares in total investment, the share of self-financing will increase from 9% to 23% within five years time. In the next 5 years (2008–2012), this share will be in the range of 32% to 86%, before reaching the level of 100% in 2013 and years thereafter.

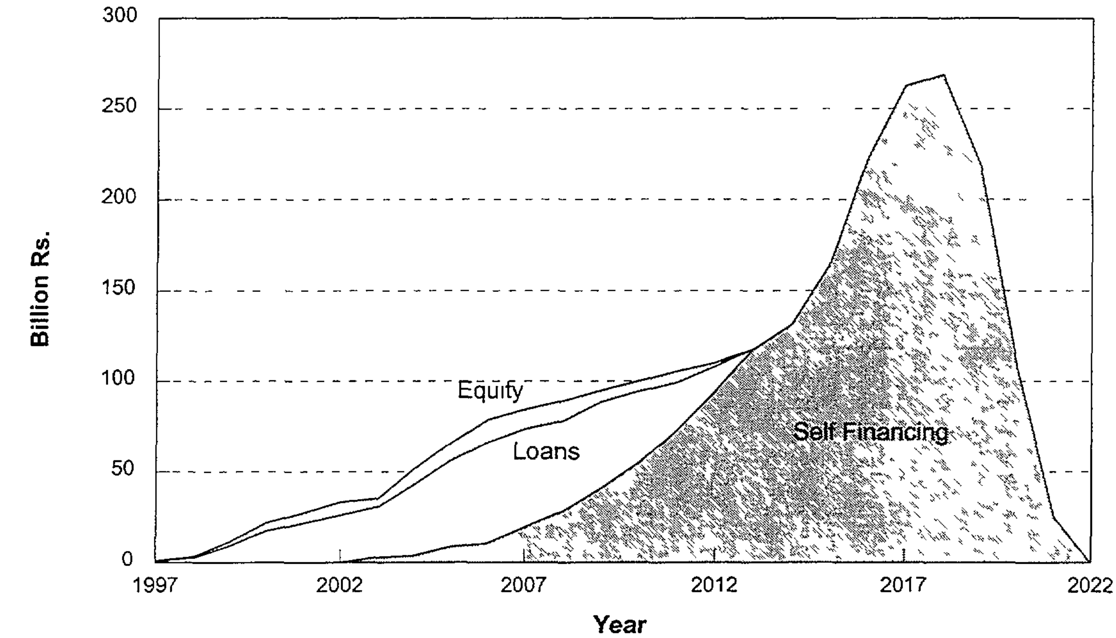

Figure 9.2 Annual Investment Cash Flows for the Nuclear Power ExpansionPlan (in Current Prices)

Column 5 in Table 9.5 shows that the annual equity requirements will be in the range of Rs. 218 million to Rs. 12.4 billion in the first 10 years of the planning period (1997–2006). The annual demand for the equity fund will be increasing till the year 2006 but will start declining in the years afterward. Starting from the year 2013, no equity fund will be required.

The annual loan requirement of the company will be in the range of Rs. 870 million to Rs. 55.1 billion. These demands will be increasing in the first 10 years of the expansion plan (1997–2006), but will start declining in the year 2007 before the company reaches the stage of 100% self-financing in the year 2013.

Debt Servicing

Table 9.6 reports the annual debt service liabilities in the financial plan worked out above. Columns 2 and 3 give the annual repayment of and interest on foreign debt respectively for the planning period. Since IDC of all types of loans have been assumed to be paid from the equity, and the grace period for all types of loans have been assumed as 6 years, the debt servicing will start in the year 2003; the first year of operation of the first plant. The first debt service installment on foreign loans will be US $0.15 billion; of which US $ 0.08 billion will be for repayment of the loans. The debt service liabilities on foreign loans during the planning period will be in the range of US $145 million to about US $1 billion. In local currency, these correspond to Rs. 5.8 to about Rs. 57 billion. The cumulative debt service payment on the foreign loans will be Rs. 763.2 billion (equivalent to US $13.5 billion) during the planning period.

Table 9.5. Annual Investment Cash Flows for the Nuclear Power Expansion Plan (in Current Prices)

(Billion Rs.)

Year	Total Investment	Self Financing	Loans	Equity
(1)	(2)	(3)	(4)	(5)
1997	1.088	0.000	0.870	0.218
1998	2.981	0.000	2.375	0.606
1999	11.131	0.000	8.865	2.266
2000	21.915	0.000	17.382	4.532
2001	27.383	0.000	21.525	5.858
2002	33.412	0.000	26.021	7.391
2003	35.216	3.029	27.728	4.459
2004	51.532	3.877	38.694	8.960
2005	65.453	8.942	46.963	9.548
2006	78.306	10.859	55.070	12.377
2007	83.969	19.384	53.742	10.843
2008	88.968	28.202	49.210	11.555
2009	94.192	40.062	47.593	6.536
2010	100.007	54.991	39.148	5.868
2011	105.438	72.933	26.251	6.254
2012	110.011	94.151	13.804	2.056
2013	117.804	117.804	0.000	0.000
2014	131.125	131.125	0.000	0.000
2015	163.913	163.913	0.000	0.000
2016	222.000	222.000	0.000	0.000
2017	262.483	262.483	0.000	0.000
2018	268.941	268.941	0.000	0.000
2019	218.051	218.051	0.000	0.000
2020	107.013	107.013	0.000	0.000
2021	24.876	24.876	0.000	0.000
2022	0.000	0.000	0.000	0.000
Total	2427.206	1852.637	475.242	99.327

Columns 5 and 6 report the annual debt service on local loans which amounts to about Rs. 84 billion for the whole planning period. The maximum annual debt service liability on local loans will be about Rs. 7 billion in the year 2012 starting from about Rs. 1.14 billion in 2003. Total annual debt service liabilities of the company will be in the range of Rs. 7 to Rs. 64 billion, accumulating to about Rs. 847 billion for the entire planning period (see Table 9.6).

Table 9.6. Debt Service Liabilities for the Nuclear Power Expansion Plan (in Current Prices)

(Billion)

	Foreign Loan Debt Service			Local Loan Debt Service			
Year	Loan Repayment (US $)	Interest payment (US $)	Total Foreign Debt Service (Rs.)	Loan Repayment (Rs.)	Interest payment (Rs.)	Total Local Debt Service (Rs.)	Total Debt Service (Rs.)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
2003	0.068	0.077	5.844	0.437	0.699	1.135	6.98
2004	0.068	0.072	5.808	0.437	0.629	1.065	6.87
2005	0.139	0.146	12.212	0.892	1.288	2.180	14.39
2006	0.139	0.136	12.119	0.892	1.145	2.037	14.16
2007	0.200	0.198	18.061	1.260	1.591	2.852	20.91
2008	0.270	0.263	24.917	1.808	2.266	4.074	28.99
2009	0.336	0.321	31.622	2.224	2.643	4.867	36.49
2010	0.394	0.363	37.593	2.667	2.995	5.662	43.26
2011	0.447	0.396	43.107	3.138	3.322	6.459	49.57
2012	0.502	0.427	48.921	3.638	3.620	7.259	56.18
2013	0.521	0.443	52.285	3.434	3.411	6.845	59.13
2014	0.550	0.437	55.121	3.682	3.257	6.939	62.06
2015	0.550	0.428	56.252	3.490	3.089	6.579	62.83
2016	0.565	0.404	57.424	3.572	2.663	6.236	63.66
2017	0.556	0.372	56.624	3.292	2.233	5.525	62.15
2018	0.536	0.333	54.626	2.770	1.747	4.517	59.14
2019	0.517	0.293	52.438	2.354	1.304	3.658	56.10
2020	0.497	0.254	50.120	1.911	0.927	2.838	52.96
2021	0.439	0.217	45.077	1.441	0.621	2.062	47.14
2022	0.424	0.184	42.988	0.940	0.391	1.331	44.32
Total	7.718	5.766	763.160	44.279	39.841	84.120	847.28

Annual Foreign Exchange Requirements

Table 9.7 reports the annual foreign exchange requirements for debt services, foreign fuel costs, IDC paid from the equity funds and investment cost met from the internally generated funds of the company during the planning period (1997 to 2022). The annual requirement will vary in the range of US $1 million to US $4.2 billion, accumulating to US $34.5 billion for the whole planning period.

Except for the IDC payment, local currency equivalent of these foreign exchange requirements will be available from the company's revenues. Thus, only a small fraction of these requirements will be unsupported, and which will come from the government's resources.

Table 9.7. Foreign Exchange Requirements of the Nuclear Power Expansion Plan (in Current Prices)

(Billion US $)

Year	Foreign Loan Repayments	Fuel	IDC paid from Equity	Interest	For Currency Requirement for Self-Financing	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1997	0.000	0.000	0.000	0.000	0.000	0.000
1998	0.000	0.000	0.000	0.000	0.000	0.000
1999	0.000	0.000	0.001	0.000	0.000	0.001
2000	0.000	0.000	0.004	0.000	0.000	0.004
2001	0.000	0.000	0.010	0.000	0.000	0.010
2002	0.000	0.000	0.018	0.000	0.000	0.018
2003	0.068	0.029	0.001	0.077	0.000	0.107
2004	0.068	0.030	0.006	0.072	0.000	0.107
2005	0.139	0.061	0.006	0.146	0.000	0.214
2006	0.139	0.063	0.006	0.136	0.087	0.293
2007	0.200	0.099	0.006	0.198	0.169	0.471
2008	0.270	0.136	0.006	0.263	0.174	0.580
2009	0.336	0.176	0.002	0.321	0.331	0.829
2010	0.394	0.219	0.002	0.363	0.535	1.119
2011	0.447	0.264	0.004	0.396	0.621	1.285
2012	0.502	0.312	0.001	0.427	0.855	1.595
2013	0.521	0.364	0.000	0.443	1.261	2.068
2014	0.550	0.418	0.000	0.437	1.493	2.348
2015	0.550	0.476	0.000	0.428	1.856	2.760
2016	0.565	0.537	0.000	0.404	2.127	3.069
2017	0.556	0.603	0.000	0.372	2.637	3.612
2018	0.536	0.672	0.000	0.333	3.181	4.186
2019	0.517	0.794	0.000	0.293	3.036	4.124
2020	0.497	0.925	0.000	0.254	1.487	2.667
2021	0.439	1.064	0.000	0.217	0.371	1.652
2022	0.424	1.211	0.000	0.184	0.000	1.395
Total	7.718	8.452	0.074	5.766	20.221	34.5131

Funds for Decommissioning of Nuclear Power Plants

The operation and maintenance cost for nuclear power plants includes 1 mill/kW.h (in 1993 prices) to cover the cost of decommissioning of these plants at the end of their operating lives. As per worldwide general practice, this part of the O&M cost has been assumed to be invested in some long term interest bearing saving schemes. The rate of interest has been assumed as 10% per annum. At the end of the operational life of each plant, this fund will grow to a level to cover the cost of decommissioning.

Table 9.8. Decommissioning Fund in current prices (Billion Rs.)

Year	Annual Contribution	Interest	Cumulative inc. Interest
2003	0.232	0.023	0.255
2004	0.247	0.050	0.551
2005	0.525	0.108	1.184
2006	0.559	0.174	1.918
2007	0.894	0.281	3.093
2008	1.269	0.436	4.797
2009	1.689	0.649	7.135
2010	2.159	0.929	10.223
2011	2.682	1.291	14.196
2012	3.265	1.746	19.206
2013	3.911	2.312	25.430
2014	4.628	3.006	33.064
2015	5.422	3.849	42.334
2016	6.300	4.863	53.497
2017	7.268	6.077	66.842
2018	8.336	7.518	82.696
2019	9.512	9.221	101.428
2020	10.806	11.223	123.457
2021	12.227	13.568	149.253
2022	13.788	16.304	179.345

Table 9.8 shows the annual contribution of all operating plants to the decommissioning fund, annual interest earned and the cumulative amount in the fund. At the end of study period, a total of Rs. 179.3 billion would be accumulated, while during this period none of the plants will retire. The first nuclear power plant will retire in the year 2032 and the decommission fund for this plant alone would have grown to Rs. 79 billion by that time, which will be adequate to cater for its decommissioning. Likewise, for subsequent plants, sufficient funds would be available at the end of their operational lives for decommissioning.

9.4.2. Financial Ratios

As previously discussed, the FINPLAN model computes the Financial Ratios which indicate the financial health of the company. Table 9.9 reports the values of these ratios for the nuclear power company from the year 2003 to 2022. Because the company is newly established, these ratios are not valid or meaningful for the construction period of the first plant (1997–2002). The definition of the Financial Ratios and their values are discussed in the following paragraphs.

Debt service coverage ratio: It is the ratio of the debt service liabilities to the annual cash flow of a company, and is most commonly used by the commercial banks to financially evaluate a company for the purpose of lending money. In the international financial market, the debt service coverage ratio for a project is generally expected to be around 1.5 or higher for loan borrowing. For the nuclear power company, throughout the study period, this ratio comes out to be higher than 1.5 in the proposed financial plan, indicating that the company's annual cash flows will be much bigger than its debt service liabilities.

Table 9.9. The Financial Ratios for the Nuclear Power Company in the Reference Case

Year	Debt Service Coverage	Leverage	Exchange Risk	Break-even Point	Interest Charge Weight
2003	1.77	3.64	0.56	0.80	0.46
2004	2.03	3.61	0.26	0.87	0.54
2005	2.02	3.44	0.71	0.70	0.38
2006	1.99	3.45	0.67	0.75	0.43
2007	2.01	3.21	0.99	0.65	0.35
2008	2.07	2.96	1.23	0.61	0.31
2009	2.09	2.80	1.45	0.56	0.27
2010	2.24	2.56	1.60	0.52	0.24
2011	2.45	2.24	1.80	0.48	0.21
2012	2.63	1.94	1.99	0.44	0.18
2013	3.04	1.59	2.27	0.39	0.15
2014	3.51	1.27	2.55	0.35	0.12
2015	4.15	0.95	2.83	0.31	0.10
2016	4.83	0.71	3.03	0.28	0.08
2017	5.75	0.55	3.35	0.25	0.06
2018	6.95	0.42	3.83	0.22	0.05
2019	8.91	0.28	4.67	0.19	0.04
2020	11.31	0.17	5.61	0.17	0.03
2021	15.04	0.09	6.54	0.15	0.02
2022	18.73	0.06	7.11	0.14	0.01

Leverage ratio: It expresses the ratio between the debt of the company and its liabilities. According to the Government of Pakistan's policy for private power generation, the minimum debt to equity ratio can be 80:20, i.e. the value of the leverage ratio can at the most be 4. In the proposed financial plan of the nuclear power company, the value of this ratio is in the range of 3.6–3.0 in the initial years of the study period, and it keeps on declining to become less than 1.0 in the years after 2015. This indicates that the company's debt will become less than its liabilities 12 years after the commissioning of the first plant.

Exchange-rate risk ratio: The nuclear power company has annual cash flow in local currency but it needs foreign currency every year for servicing of foreign debt, purchase of imported fuel and to make investment in foreign currencies from its own resources. This ratio expresses a security margin in local cash flow with respect to the unforeseen increase in the exchange rate. Except for the initial few years of the study period, the company's local cash flows will be much bigger than its foreign exchange requirements. Values of the exchange risk ratios in the proposed plan are in the range of 1.23 to 7.11 in the year 2008 and thereafter.

Break-even ratio: It is the ratio of fixed charges of the company, including repayments of the company's debt, to the value added (total revenues net of variable cost) of the company. A value of 0.8 of this ratio corresponds to a safety margin of 20%. For the nuclear power company, this ratio is 0.80 in the first year of electricity generation, and except for the second year, it keeps on declining throughout the study period indicating that fixed charges of the company will be declining with respect to its value added.

Interest-charge-weight ratio: The ratio gives the relative weight of the financial expenditure in relation to the value added. It is a ratio of total interest to the company's value added. Values of 0.20 or more of this ratio indicate that the company is only running business in order to repay its creditors. For the nuclear power company, this ratio is in the range of 0.54 to 0.01. The ratio has high values only in the initial years of the study period. It starts declining steadily 4 years after the commissioning of the first plant, indicating that the amount of interest will become much smaller than the company's growing value added.

9.4.3. Sensitivity Analysis

The above analysis is subject to the assumed values of various financial parameters and capital costs. Among these, capital costs, foreign interest rates, exchange rates and electricity sale price are of critical importance and, a variation in their assumed values may significantly change the overall results. The sensitivity of the proposed financial programme, worked out above (from now on referred to as the Reference case), has been analysed for these four parameters. The Reference case has been modified to formulate four sensitivity cases.

In Case A, capital cost has been increased to US $ 2150/kW from 1700/kW assumed in the Reference Case.

In Case B, interest rate has been increased to 9% p.a. on all types of foreign loans compared to its value of 7.5 % p.a. assumed in the Reference case.

In Case C, the exchange rate has been assumed to deteriorate more rapidly in the future compared to that in the Reference case.

In Case D, the levelized sale price of electricity has been reduced from 5.91 cents/kW.h to 4.0 cents/kW.h. The following paragraphs discuss the results of these four sensitivity cases.

Increase in Capital Cost (Case A)

The suggested increase in capital cost will increase the size of the investment plan to Rs. 3227 billion which is 33% higher than the investment requirement in the Reference case. To meet this increase in the investment plan, there will be more than 2 fold increase in loan and equity requirements. Consequently, the share of loans and equity in the total investment will increase to 40% and 8%, respectively. The loans requirements will rise to Rs. 1276 billion while the equity demand will be of Rs. 267 billion. Since, major portion of these loans will be in foreign currency to meet the foreign capital cost, there will be more than two fold increase in foreign loans in this case. The foreign loans requirements will increase to US $23 billion compared to US$10 billion in the Reference case.

The high capital cost will reduce the company's capacity to self-finance its future investments. Compared to 100% self-financing of the last 8 plants in the Reference case, the level of self-financing in this case will reach only to 70% for the last 2 plants.

Due to higher amount of loans and interest on them, the debt service liabilities of the company during the study period will rise to Rs. 1590 billion compared to Rs. 847 billion in the Reference case. In terms of foreign currency, the cumulative requirement for debt servicing will increase to US $24 billion from US $13 billion in the Reference case. The cumulative foreign currency requirement for foreign debt service, fuel and investment from self-financing will rise to US $ 38 billion from US $ 34 billion in the Reference case.

The increase in capital cost will, thus, increase loan and equity requirements but the financial plan will still be viable. The annual net operating income will be sufficient to cover the increased debt service liabilities and the dividend payments annually. The cumulative retained earnings at the end of the study period will be Rs. 1450 billion compared to equity contribution of Rs. 267 billion and outstanding loan of Rs. 722 billion.

High Foreign Interest Rate (Case B)

The most significant effect of increasing the foreign interest rate will be on foreign debt service liabilities. The results show that there will be 19% increase in foreign debt service payments during the study period which will increase to US $ 16 billion compared to US $ 13.4 billion in the Reference case.

The high debt service liabilities will reduce the share of self-financing in total investment and will thus increase loans and equity requirements. Total loan requirements will rise from Rs. 475 billion to Rs. 533 billion, while equity demand will increase from Rs. 99 billion to Rs. 110 billion

Despite increase in the debt service liabilities, the investment programme will still be financially viable as the annual net operating income of the company will be sufficient to pay the debt service annually. The cumulative retained earnings of the company will, however, be reduced to Rs. 2062 billion compared to Rs. 2187 billion in the Reference case. Nevertheless, these retained earnings are substantially higher than the equity contribution of Rs. 110 billion and outstanding loans of Rs. 173 billion at the end of the study period.

Deterioration in Exchange Rate (Case C)

In this case, it has been assumed that the US dollar to Rupee parity will deteriorate more rapidly compared to that assumed in the Reference case. One US dollar is assumed to become equivalent to Rs. 159 in 2022 compared to Rs. 70 in the Reference case. The most significant adverse effect of this deterioration in the exchange rate will be on foreign debt service liabilities in Rupees terms which will increase to Rs. 1320 billion compared to Rs. 763 billion in the Reference case.

Since the local inflation has also been assumed to increase with exchange rate deterioration, and the electricity price is indexed with local inflation, the overall cash flows of the company will remain adequate to meet its all liabilities. As such, there will be no major adverse impact on the financial plan provided that the company is able to freely convert its Rupees revenues in US dollars for all foreign exchange requirements.

Reduction in Sale Price of Electricity (Case D)

In the Reference case, the sale price of electricity at bus bar has been assumed, in line with government policy for the private sector, as 5.91 cents/kW.h (levelized for the entire life of nuclear power plant in terms of 1993 dollars). It has been pointed out by WAPDA that if nuclear power is cheaper than alternative options of electricity generation based on fossil fuels, its benefits should be transferred to the consumers and, thus, the sale price should be assumed lower than that taken in the Reference Case. Although the sale price will be agreed to between the nuclear power company and the utility responsible for transmission and distribution of electricity, in line with the government's policy, an alternative case has been analysed to investigate the impacts of lower sale price on financial viability of the proposed nuclear power programme. In this case, the sale price of electricity from nuclear power plants has been gradually decreased to determine the lowest level at which the nuclear power investment programme remains financially viable. It has been found that even at 4 cents/kW.h levelized sale price, the proposed investment programme is viable since the company is able to meet all of its operating costs and debt service liabilities from the revenue. However, the level of financing decreases because of reduced surplus income. The self financing in this case can only be started in 2009 instead of 2003 as in the Reference case. Consequently, the borrowings and equity contributions are increased.

9.5. Conclusions

Technical analysis of the financing plan worked out in this study shows that the nuclear power expansion plan envisaged in the least-cost power expansion plan of Pakistan is also financially viable at the assumed values of the various financial parameters. For the first nuclear power plant, the nuclear power company will need to raise equity of about 22% of the investment costs (Rs. 11.9 billion) but thereafter equity requirement of the company will start declining for the remaining plants. For the second plant, the earnings from the first plant will reduce the equity requirement to a level of 13.5%. This decline becomes significant for plant Nos. 8 to 14 (see Table 9.3), and no equity will be required at all for the remaining 8 plants (plant Nos. 15 to 22). Similarly, the internally generated funds will reduce the need of taking new loans. As shown in Table 9.3, starting from 78% of the total investment cost for the first plant, new loans will comprise about 24% of the total investment cost of the 10th plant and only 1.8% for the 14th plant. The plants Nos. 15 to 22 will be fully financed from the company's internally generated funds.

The cash flows of the company are not only sufficient to cover the operating costs and debt service liabilities, but will also finance a part of future investments of the company. The value of debt service ratios throughout the planning period are greater than 1.5 implying that the company's cash flows will be much higher than its debt servicing liabilities, and these ratios become as high as 6.54 towards the end of the planning period. Furthermore, the total retained earning at the end of the planning period will be about Rs. 2187 billion (see Table 9.10) compared to Rs. 99.3 billion of the equity fund and about Rs. 145 billion outstanding loans (both local and foreign). This retained earnings is in addition to about Rs. 186 billion paid as dividend on the equity during the planning period.

One critical aspect of this financial plan is the liquidity problem of the foreign currency as the company's cash flows will be in local currency, while it will have a significant foreign exchange requirement for annual debt servicing and fuel expenditure. It has been realized that there is a considerable loss in GDP due to power shortage every year, and most of this loss is incurred in the industrial sector. A recent survey of industrial enterprises indicates that infrastructure bottlenecks, in particular power shortages, are considered major obstacles to operation and growth of the industrial sector of Pakistan [26]. [87] estimated the power outage cost in the industrial sector in Pakistan as US $ 0.90/kW.h. Thus, alleviating the power shortage will result in better growth in the industrial sector and in the country's GDP.

Furthermore, in view of incentives given for promotion of exports in the current policy of the government and foreseen growth in world economies, the expansion in electricity supplies at a reasonable price is expected to increase the exports of Pakistan and thereby increasing its foreign exchange earnings.

It may be pointed out that many assumptions made in the present financial analysis are on conservative side. For example, it has been assumed that the nuclear power company will sell electricity at the levelized tariff throughout the operational life of its plants rather than charging the permissible higher tariff for the first ten operation years of each plant. This implies that the cash flows of the company are under estimated during the loan replacement period for a plant which increases the company's debt servicing costs. If the option of changing higher tariff is used, the overall cash flow position of the company will further improve thereby improving the financial indicators.

Table 9.10. Annual and Cumulative Retained Earnings

(Billion Rs.)

Year	Net Operating Income	Dividend Payment	Self Financed Investment	Debt Service	Retained Earnings (Annual)	Retained Earnings (Cumulative)
1997	0.000	0.000	0.000	0.00	0.000	0.000
1998	0.000	0.000	0.000	0.00	0.000	0.000
1999	0.000	0.000	0.000	0.00	0.000	0.000
2000	0.000	0.000	0.000	0.00	0.000	0.000
2001	0.000	0.000	0.000	0.00	0.000	0.000
2002	0.000	0.000	0.000	0.00	0.000	0.000
2003	11.428	1.420	3.029	6.98	0.000	0.000
2004	12.170	1.420	3.877	6.87	0.000	0.000
2005	25.920	2.586	8.942	14.39	0.000	0.000
2006	27.602	2.586	10.859	14.16	0.000	0.000
2007	44.089	3.792	19.384	20.91	0.000	0.000
2008	62.600	5.407	28.202	28.99	0.000	0.000
2009	83.328	6.777	40.062	36.49	0.000	0.000
2010	106.483	8.237	54.991	43.26	0.000	0.000
2011	132.291	9.792	72.933	49.57	0.000	0.000
2012	161.001	10.671	94.151	56.18	0.000	0.000
2013	192.880	11.443	117.804	59.13	4.504	4.504
2014	228.219	12.266	131.125	62.06	22.769	27.273
2015	267.331	13.142	163.913	62.83	27.445	54.718
2016	310.559	13.418	222.000	63.66	11.480	66.198
2017	358.271	13.712	262.483	62.15	19.926	86.124
2018	410.868	13.798	268.941	59.14	68.985	155.110
2019	500.035	13.798	218.051	56.10	212.089	367.199
2020	599.043	13.798	107.013	52.96	425.274	792.473
2021	708.796	13.798	24.876	47.14	622.983	1415.455
2022	830.270	13.798	0.000	44.32	772.153	2187.608
	5073.185	185.660	1852.637	847.280	2187.608	

Similarly, while calculating foreign exchange requirements, it has been assumed that the ratio between foreign and local cost components will remain constant, whereas in real situation, the local cost component is expected to increase with time as a result of indigenization efforts. As such, the annual foreign exchange requirements will be considerably lower than those estimated in the present analysis, particularly towards the end of study period.

It is thus clear that if the above mentioned aspects are also taken into account, the financial viability of the proposed nuclear power development programme becomes more attractive.

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Chapter 10

CONCLUSIONS AND RECOMMENDATIONS

The Energy and Nuclear Power Planning Study for Pakistan has been carried out by the Applied Systems Analysis Group in Pakistan Atomic Energy Commission with technical assistance from the International Atomic Energy Agency.

This study is the first of its kind in terms of its coverage. It analyses the entire energy system of the country including: the analysis of future evolution of energy and electricity demand, evaluation of future supply potential of indigenous energy resources and import possibilities, development of overall energy demand and supply balance, formulation of least-cost expansion plans for the electricity generation system, environmental analysis of electricity generation and financial analysis of envisaged nuclear power development plan.

All the earlier studies conducted so far have covered some of these aspects but no one has such a comprehensive coverage. The national team has acquired a very valuable experience in carrying out this study and has developed the capabilities to conduct such studies in future with little external help. These capabilities would be very useful for national energy, electricity and nuclear power planning efforts by PAEC as well as by other national organizations. Further, the set of models acquired will also be available to other national organizations for their future studies.

10.1. Conclusions

10.1.1. Energy and Electricity Demand

The demand for commercial energy has been projected to increase at a growth rate of about 7% per annum in the Reference Scenario, i.e., from 22.6 million TOE in 1993 to 168.9 million TOE in 2023. Since the economic growth in this scenario has been assumed as 7% p.a. throughout, the income elasticity of energy demand works out at about 1.

If the future economic growth turns out to be higher as assumed in the Optimistic Scenario then the energy demand will also grow at a higher rate (8.9% p.a.), and, similarly, if the economic growth is lower (5.7% p.a.) as assumed in the Constrained Scenario the growth of energy demand will also be lower (5.1% p.a.).

In all these cases, the income elasticity of energy demand is close to unity. This indicates that the future evolution of energy demand will mainly be dictated by the pace of growth of the national economy and its rate of growth will be more or less in line with that of economic growth. However, if a vigorous effort is made on improving energy efficiency and energy conservation, as assumed in the Energy Efficiency Scenario, then the energy demand in the terminal year will be about 25% lower compared to that projected in the Reference Scenario. This means that the same economic growth (7% p.a.) can be achieved using about 25% less energy if energy conservation and efficiency improvement measures are implemented.

The future demand for electricity has been projected to grow at 7–11% p.a. in different scenarios as shown below:

	Growth Rate of Electricity Demand (% per annum)	
	1993–2003	1993–2023
Reference Scenario	8.9	8.7
Optimistic Scenario	9.6	10.6
Constrained Scenario	8.1	6.9
Energy Efficiency Scenario	8.3	8.0

On a per capita basis the electricity consumption level in Pakistan will improve by a factor of 4–10 in different scenarios by the year 2023 (6.3 times in the Reference Scenario). Still the per capita consumption level in the Reference Scenario in 2023 will be only 1/4th of the present average for the OECD countries and only 20% higher compared to the present per capita consumption level in Brazil.

The peak demand corresponding to the above projections at the end of 9th Five Year Plan and at the end of planning horizon has been worked out as:

	Peak Demand (MW)	
	2003	2023
Reference Scenario	16 025	83 550
Optimistic Scenario	17 220	146 040
Constrained Scenario	14 925	49 415
Energy Efficiency Scenario	15 020	67 485

The net power generation capacity additions over the 30 years study period will range from 68 000 to 147 000 MW in different scenarios. Such a large capacity addition will not only require large investments and commitment of other resources, it will also result in heavy environmental burden if appropriate measures are not taken.

10.1.2. Overall Energy Demand–Supply Balance

In order to meet the projected energy demand it is expected that the country will continue to be dependent on energy imports. The energy import dependence, in the Reference Scenario, will remain within 32–38% of the total primary energy requirements during the next 20 years but will increase further thereafter, reaching about 48% at the end of planning horizon. This is despite the fact that a considerably large increase has been assumed in the future supplies from indigenous energy resources. The oil and gas production from indigenous sources has been assumed to increase from 2.9 million TOE of oil and 12.4 million TOE of gas in 1993 to 11.5 million TOE of oil and 45.1 million TOE of gas in the year 2023, and the hydroelectric production has been assumed to increase from 5 million TOE in 1993 to about 14 million TOE in 2023. The contribution of nuclear power in the total primary energy supplies has been estimated to increase from 0.3% now to 2.6% at the end of 9th Five Year Plan (2003) and to about 9% at the end of planning horizon (2023).

If the future energy demand happens to be as projected in the Optimistic Scenario then the energy import dependence will reach a level of about 70% by the end of planning horizon.

However, if the future energy demand turns out to be as projected in the Constrained Scenario or Energy Efficiency Scenario, the energy import dependence will slightly decrease from the present level of 32% to about 30%.

The overall energy demand–supply analysis has further shown that all the three projects of importing natural gas from neighbouring countries, which are being seriously considered by the government, will be required over the next thirty year period.

10.1.3. Least-Cost Plan for Expansion of Electricity Generation System

A total of 83 100 MW of power generation capacity has to be added over the period 1993 to 2022 to meet the electricity demand as projected in the Reference Scenario. Due to limitations on the pace of development of hydro power and nuclear power, a large fraction of the capacity addition will have to be based on fossil fuels. The least cost plan worked out with the help of optimization model WASP shows installed capacity to be as given below:

	Installed Capacity (MW)	
	2003	2022
Hydro	6662	14 502
Gas	6364	29 216
Coal	1162	16 150
Oil	5113	18 222
Nuclear	1050	13 525
Total	20 351	91 615

The total additions, net of retirements, of power generation capacity in the Reference Case over the 30 years period have been estimated as about 84 000 MW. The contribution of nuclear power in total capacity additions is 13 200 MW, which remains unchanged under wide variation of certain important parameters, for example capital cost, discount rate and prices of alternative fuels.

10.1.4. Alternative Plans for Expansion of Electricity Generation System

In order to analyze the main uncertainties surrounding the future development of electric sector in Pakistan, a number of alternative plans for future expansion of electricity generation system have been formulated and analyzed. Two alternatives assume the same electricity demand and all other supply assumptions as in the Reference Case, except that in Alternative I there is a moratorium on development of nuclear power while the Alternative II assumes no imports of natural gas.

In Alternative I all the nuclear power capacity has been replaced with oil fired power plants. This increases the energy import dependence of the country by some 10 percentage points by the end of planning horizon. In Alternative II, the gas fired capacity based on imported gas has also been replaced by oil fired power plants.

Alternative III corresponds to meeting electricity demand as projected in the Energy Efficiency Scenario. Although, in this case, the electricity demand is some 17% lower compared to the Reference Case, still all the nuclear power capacity additions are part of the least cost plan for this case. The hydro power and gas based capacity additions are also same as in the Reference Case. The main difference is that no additional oil fired plants are required in this case.

As an extreme case, another alternative plan has been analyzed with electricity demand as projected in the Optimistic Scenario. This plan shows that about 147 000 MW of power generation capacity will be required by the end of planning horizon as compared to about 84 000 MW in the Reference Case. Since hydro, nuclear and gas based capacity additions are already at their maximum technical limits, all the additional capacity required in this case will have to be based on imported coal and oil (mainly imported oil). As a result, the import dependence in this case will increase substantially.

As of the latest (July, 1996), the situation of the power development has somewhat changed due to maturity of some private power projects. In order to reflect these developments, an additional case has been analysed which includes 4320 MW of power capacity in the private sector as an additional committed part of the electricity generation expansion plan. Inclusion of this additional capacity changes the optimal expansion plan of the Reference Case in the initial years. The first nuclear plant is shifted from 2003 to 2004 and some of the combined cycle power plants are delayed. However, the total capacity based on nuclear power and combined cycle power plants remains the same as in the Reference Case.

10.1.5. Investment Requirements

The total investment required over the 30 year study period for building up the electricity generation system proposed in the Reference Case has been estimated as US $108 billion (in 1993 prices). This investments is some US $15 billion higher compared to those required for the case with nuclear moratorium. But if the system operation costs (fuel and O&M costs) are also taken into account then the generation system of the Reference Case becomes economically attractive.

The cumulative cost, over the 30 year planning horizon, for system operation in the Reference case is US $172 billion compared to US $205 billion in the nuclear moratorium case. Further, the energy import dependence of the country in the Reference Case is lower by some 10 percentage points compared to that in the case without nuclear power.

The total investment required for building the electricity generation system for meeting the demand projected for the Energy Efficiency Scenario is about 17% lower compared to that for the Reference Case. Although, the investment required to implement the energy efficiency measures has not been estimated in this study, it is felt this would be significantly lower than the cost of avoided capacity additions.

10.1.6. Environmental Assessment

Environmental analysis of the alternative plans for the expansion of electricity generation system shows that irrespective of the mix of future electricity generation system, the environmental burdens in Pakistan due to the electric sector will increase by a factor of about ten. However, the electricity generation system of the Reference Case is the cleanest system because of the inclusion of nuclear power plants which do not emit any of the noxious gases like SO_2, NO_x, CO_2, etc.

The radioactive emissions from nuclear power plants are kept well within the permissible limits specified by the international organizations and are generally much lower compared to that emitted by some coal fired plants (the coal fired plants are not equipped with any system for containing the radioactive elements present in the coal). Further, if pollution control devices are added to the fossil fuel fired plants, it has been estimated that the investment and operation costs of such devices will increase the overall cost giving again significant margin to nuclear power.

10.1.7. Financial Analysis

The financial analysis of the envisaged nuclear power development plan shows that the plan is financially viable under the assumed terms of financing. These terms have been assumed in line with the internationally accepted practices and the recent policy of the government for private power producers in Pakistan.

For the first nuclear power plants, it has been assumed that the government will provide equity to the extent of 22% of its investment and the remaining funds will be generated from foreign and local loans. However, as the nuclear power plants become operational and start generating revenues, the surplus earnings, available after meeting all operational costs, debt servicing and dividend payment, can be used for investment in future plants. These earnings after about 15 years will become sufficient to cover almost 100% of the investment required for the subsequent plants.

10.2. Recommendations

The detailed analyses carried out in this study show that the demand for energy and electricity will continue to increase in the coming years at about 7% and 9% per annum respectively, and that the future supplies from indigenous energy resources will remain inadequate to meet the projected demand. As such, the country will continue to be dependent on imported fuels. Furthermore, due to increased use of energy the environmental emissions from energy sector will increase many folds, threatening severe degradation of natural environment. In order to combat these problems, the study has shown that the following measures should be taken:

- Vigorous efforts should be made to increase the efficiency of energy and electricity use in all sectors of the economy in order to contain fast growth in demand. Major consumers as well as the general public should be encouraged, through appropriate fiscal and regulatory measures, to use efficient appliances and to avoid wasteful use of energy and electricity. Besides, concerted efforts should be made to implement the plans for reduction in transmission and distribution losses of electricity.

- An all out effort should be made to explore and rapidly develop additional indigenous energy resources. In this regard, emphasis should be given to petroleum exploration effort since oil and gas are expected to remain the major sources of energy supply in the coming years. The recently identified large coal filed, Thar, should rapidly be developed and put to use in an environmentally acceptable manner. The identified hydro power projects should be developed as fast as possible and additional small and medium hydro power projects should be identified and developed.

- Concerted efforts should be made to develop nuclear power in order to reduce energy import dependence of the country and to avoid excessive degradation of natural environment. Based on the analysis of various alternative scenarios, it is recommended that construction of a 600 MW nuclear power plant should be started in the current Five Year Plan period and of 2–3 more nuclear plants in the 9th Five Year Plan period. Beyond that, the pace of nuclear power development should be further increased to develop maximum technically feasible capacity of nuclear power (which in this study has been estimated as about 13 500 MW over the next 30 years). The Government should provide financial support for construction of the first few nuclear power plants which, on becoming operational, will generate sufficient surplus income to cover the investment requirements of subsequent plants.

- Systematic efforts should be initiated to gradually indigenize the nuclear power technology in order to implement the envisaged nuclear power development programme in an increasingly self-reliant manner. This will reduce foreign dependence for construction of future nuclear as well as thermal power plants and will effectively expand the overall industrial base of the country. In this respect, a detailed national plan should be worked out for development of necessary infrastructure facilities for design and engineering as well as manufacturing of various systems and sub-systems of nuclear power plants. Further, the manpower requirements and the organizational structure for implementation of the nuclear power programme should be assessed and developed.

- A 300 MW nuclear power plant is presently under construction at the Chashma site which can accommodate up to 10 more units. Thus, there would not be any problem related to space and other site specific requirements for starting construction of additional nuclear power units in the near future. However, for reasons of phased development and grid requirement, it would be expedient to identify and thoroughly investigate additional sites in the country, specially in the coastal areas. It is, therefore, recommended that studies be initiated for identification and investigation of new sites for construction of future nuclear power plants.

- Since the power sector has been opened to private investors (both foreign and local private entrepreneurs) for construction of fossil fuel based power plants as well as hydro power plants, it would be desirable to encourage private investors to participate, as partners of the public sector, for construction of nuclear power plants.

Appendix A

RECONSTRUCTION OF THE ENERGY CONSUMPTION FOR THE BASE YEAR

The application of the MAED model requires detailed information about demography, economy, energy consuming technologies (e.g. number of tractors, vehicles on the road, etc.) and energy consumption, based on which, future energy scenarios are developed. This information is required to be assembled at first for a base year which is used as reference year for perceiving the evolution of the energy system in future. Selection of the base year is made on the basis of, (i) availability of data and (ii) the assessment that the data are representative of the economic and energy situation of the country. As the Applied Systems Analysis Group, using an adapted version of the MEDEE-2 model had already carried out some studies on energy demand assessment for Pakistan [39, 40], the status of availability of data was known to the study team. After reviewing the available data and considering the five year planning cycle in Pakistan, the 1992–93 fiscal year has been selected as the base year for the study. This fiscal year corresponds to the end of the 7th Five Year Plan.

Most of the information needed for the application of the MAED model was available for the base year. However, in some cases the information available was not up-to-date, e.g. break-up of value added and energy consumption in industry by type of major industry. In such cases the information derived from the most recent available data has been extrapolated/ adjusted in the light of partial information and aggregate data available for latter years, so as to provide reasonable estimates for the year 1992–93. In few cases no information was available, e.g. break-down of useful thermal energy requirements of manufacturing industries into furnace and direct heat, steam and space and water heating. In such cases estimates have been made on the basis of information reported in literature for other countries. The main data sources and assumptions for this phase of the study are summarized below.

A.1. Demography

The information required on account of demography is population, its rural-urban split, population of large cities (large cities have been considered here as those having population greater than 0.5 million), number of households (dwellings), household size (person per dwelling), potential labour force and labour force actually working. Although, the population census due in 1991 has not been conducted yet, most of the required information is compiled, and published by Federal Bureau of Statistics on yearly basis, based on various surveys conducted from time to time. The information related to the labour force actually working has been derived from Pakistan Economic Survey, 1995. This information for the demographic parameters for the base year is listed in Table A.1.

A.2. Macro Economy

Information on GDP and its production structure is available from Pakistan Economic Survey. However, some re-grouping of different sub-sectors of the economy was required in order to match the input requirements of MAED (see Table A.2). The GDP and its structure, compatible with the MAED framework, for the base year are listed in Table A.3.

Table A.1. Demographic Indicators for the Base Year (1992–93)

Parameters	Value	Growth rate [(1)] [%]	Share[(2)] [%]
1 Total population	120 83 million	3 09	100
2 Urban population	38 06 million	4 03	31 50
3 Population in cities with more than 0 5 million inhabitants	23 56 million	5 33	19 50
4 Persons per household			
Urban	7 075	–	–
Rural	7 244	–	–
Country average	7 190	–	–
5 Working age population (potential labour force)	79 23 million	2 92	65 57
6 Potential labour force actually working	31 98 million	2 46	26 47

[(1)] Relative to 1980–81
[(2)] Relative to total population
Source [10,11]

Table A.2. Regrouping of Pakistan's Economic Sectors According to the Structure of GDP Formation in the MAED Model

Economic sector in the MAED model	Economic sector of the Pakistan Economic Statistics
1 Agriculture	1 Agriculture (including crops, livestock, fishing and forestry)
2 Construction	2 Construction
3 Mining	3 Mining and Quarrying
4 Manufacturing	4 Manufacturing
4 1 Basic materials	4 1 1 Paper and paper products, printing and publishing,
	4 1 2 Chemicals, petroleum refining, petroleum/coal/rubber and plastic products,
	4 1 3 non-metallic mineral products(except petroleum and coal),
	4 1 4 Iron and steel basic industries
4 2 Machinery & equipment	4 2 Fabricated metal product and equipment
4 3 Non-durable/Consumer goods	4 3 1 Food, beverages and tobacco,
	4 3 2 Textiles, wearing apparels, leather and products,
	4 3 3 Wood and products, furniture and fixtures,
	4 3 4 Other Manufacturing industries and handicrafts
4 4 Miscellaneous/Small scale industries	4 4 Small scale industries
5 Energy	5 Electricity and gas distribution
6 Services	6 1 Transport, storage and communication
	6 2 Wholesale and retail trade
	6 3 Finance and insurance
	6 4 Ownership of dwellings
	6 5 Public administration and defense
	6 6 Services

Table A.3. GDP Formation in the Base Year (1992–93)

Sector	GDP		Growth rate[1]	Share
	10^9 Rs.	10^9 US $[2]	[%]	[%]
1. Agriculture	297.816	11.472	3.59	24.81
2. Construction	49.807	1.919	5.68	4.15
3. Mining	7.403	0.285	8.54	0.62
4. Manufacturing	(207.568)	(7.996)	7.07	17.29
4.1 Basic materials	(50.636)	(1.951)	–	(24.39)
4.2 Machinery & equipment	(14.262)	(0.549)	–	(6.87)
4.3 Consumer goods	(77.402)	(2.982)	–	(37.29)
4.4. Miscellaneous	(65.268)	(2.514)	8.40	(31.44)
5. Energy	38.790	1.494	10.85	3.23
6. Service	599.071	23.077	5.82	49.90
Total	1200.455	46.243	5.54	100

[1] Relative to 1982–83
[2] 1 US $ = 25.9598 Rs. of (1992–93)

Source: [10]

Structure of Manufacturing Sector: The Manufacturing sector value added, for use in the MAED model, can be subdivided up to four sub-sectors i.e. (1) Basic materials, (2) Machinery and equipment, (3) Non-durable/Consumer goods and (4) Miscellaneous. The data in the Pakistan Economic Survey corresponding to Large Scale Manufacturing industries (sum of sub-sectors 1,2 and 3) and Small Scale Manufacturing industries (sub-sector 4) are available up to 1992–93. The split of Large Scale Manufacturing industries into sub-sectors 1,2 and 3 was carried out in the light of data given in the Pakistan Economic Survey based on information obtained in various Censuses of Manufacturing Industries (CMI). The available data for the period 1969–70 to 1987–88 are plotted in Figure 3.1. The shares of sub-sectors 1,2 and 3 in the aggregate value added of Large Scale industries in the year 1992–93 have been estimated in the light of the past data. The assumed values and shares of value added of Manufacturing in various subsectors in the base year are shown in Table A.3

Structure of Transport System: Information about passenger and freight movement activity levels by different transportation modes is available from publications of the Planning Commission, National Transport Research Centre, Pakistan Railways etc. [10, 44, 56, 57, and 98]. Some of the activity levels were directly available for the base year (e.g. intercity passenger-km by rail, road and air and intercity ton-km by rail and road) while some were available only for previous selected years (e.g. estimates of intracity passenger-km by road and of intracity ton-km by road were available for 1985-86 only [56]. Based on information about vehicles on road in the base year and assumptions about shares of urban and intercity vehicles, load factors, average distance traveled by various road vehicles etc. given in [56], the intracity passenger-km and ton-km have been estimated (see also section 4.4). The ton-km by pipelines have been estimated based on the data reported in [44]. Historical and base year passenger-km and ton-km by mode are given in Tables A 4 and A.5

Table A.4. Intercity* Passenger Traffic

Year	Rail	Road	Air (Domestic)	Total	Share of different modes in total passenger traffic [%]			Population	DI **
	(Million Passenger-km)				Rail	Road	Air	(million)	(Km)
1972–73	11,069	40,577	325	51,971	21 3	78 1	0 6	65 89	789
1973–74	11,694	45,973	449	58,116	20 1	79 1	0 8	67 90	856
1974–75	12,354	49,860	559	62,773	19 7	79 4	0 9	69 98	897
1975–76	12,957	49,285	692	62,934	20 6	78 3	1 1	72 12	873
1976–77	13,199	51,765	849	65,813	20 1	78 7	1 3	74 33	885
1977–78	15,375	54,665	1,026	71,066	21 6	76 9	1 4	76 60	928
1978–79	16,713	57,219	1,093	75,025	22 3	76 3	1 5	78 94	950
1979–80	17,316	61,035	1,142	79,493	21 8	76 8	1 4	81 36	977
1980–81	16,387	65,991	1,205	83,583	19 6	79 0	1 4	83 84	997
1981–82	16,502	72,752	1,245	90,499	18 2	80 4	1 4	86 44	1,047
1982–83	18,031	79,513	1,340	98,884	18 2	80 4	1 4	89 12	1,110
1983–84	18,287	83,363	1,464	103,114	17 7	80 8	1 4	91 88	1,122
1984–85	17,806	89,952	1,615	109,373	16 3	82 2	1 5	94 73	1,155
1985–86	16,850	97,374	1,793	116,017	14 5	83 9	1 5	97 67	1,188
1986–87	16,920	87,915	2,061	106,896	15 8	82 2	1 9	100 70	1,062
1987–88	18,541	109,196	2,216	129,953	14 3	84 0	1 7	103 82	1,252
1988–89	19,732	115,226	2,268	137,226	14 4	84 0	1 7	107 04	1,282
1989–90	20,373	121,139	2,249	143,761	14 2	84 3	1 6	110 36	1,303
1990–91	19,964	128,000	2,207	150,171	13 3	85 2	1 5	113 78	1,320
1991–92	18,158	131,352	2,488	151,998	11 9	86 4	1 6	117 31	1,296
1992–93	17,082	135,000	2,545	154,627	11 0	87 3	1 6	120 83	1,280

* The intracity urban passenger kilometer in 1992–93 are estimated as 63 7 Billion PKM

** Average Intercity distance traveled per person per year

Sources [10,56 and 57]

Table A.5. Freight Traffic

Year	Rail	Road Intercity	Road Urban	Oil Pipeline	Total	Share of different modes in total freight traffic [%]		
	(Million ton-km)					Rail	Road	Pipeline
1972–73	8363	8940	516	0	17819	46.9	53.1	0.0
1973–74	7370	10129	617	0	18116	40.7	59.3	0.0
1974–75	8544	11001	707	0	20252	42.2	57.8	0.0
1975–76	9097	10327	701	0	20125	45.2	54.8	0.0
1976–77	7857	11438	819	0	20114	39.1	60.9	0.0
1977–78	8557	12319	931	0	21807	39.2	60.8	0.0
1978–79	9375	14904	1189	0	25468	36.8	63.2	0.0
1979–80	8598	17085	1439	0	27122	31.7	68.3	0.0
1980–81	7918	18207	1619	189	27933	28.4	71.0	0.7
1981–82	7067	19704	1849	1237	29857	23.7	72.2	4.1
1982–83	7323	21200	2100	1600	32223	22.7	72.3	5.0
1983–84	7385	22620	2365	1700	34070	21.7	73.3	5.0
1984–85	7203	24126	2663	1800	35792	20.1	74.9	5.0
1985–86	8270	26859	3129	1800	40058	20.7	74.9	4.5
1986–87	7820	27345	3363	2300	40828	19.2	75.2	5.6
1987–88	8033	31464	4084	2600	46181	17.4	77.0	5.6
1988–89	8364	32835	4499	2700	48398	17.3	77.1	5.6
1989–90	7226	32450	4693	2800	47169	15.3	78.7	5.9
1990–91	5709	35211	5375	2600	48895	11.7	83.0	5.3
1991–92	5962	36088	5815	2600	50465	11.8	83.0	5.2
1992–93	6180	37000	6293	3200	52673	11.7	82.2	6.1

Sources: [10, 44, 56 and 57]

A.3. Energy Consumption

Energy consumption data are regularly collected and published by the Ministry of Petroleum and Natural Resources in its annual publication Pakistan Energy Yearbook. These data are collected from oil distribution companies, gas distribution companies and power utilities and federal and provincial mining departments. The information obtained from these sources are somewhat aggregated in the Pakistan Energy Yearbook to match the main groupings of various sectors of the economy. As much more dis-aggregated information is required for the application of MAED model, additional information was obtained from oil and gas companies [44–47] and power utilities [21, 74]. Still, a number of adjustments were necessary to prepare a set of energy consumption data which could be used to derive various input parameters of MAED. The procedure adopted is summarized below:

Agriculture Sector: One anomaly of the published data on energy consumption is that the use of oil (HSD) for tractors and other farm machinery (other than diesel operated irrigation pumps) is lumped in the Transport sector. The consumption of HSD for tractors and other farm machinery was estimated on the basis of number of tractors, their average fuel usage and their annual utilization, available from various sources [e.g. Ref. 3, 14 and 15]. Another major energy consuming activity of Agriculture sector is water pumping. For this activity oil and electricity are used, for which reliable data are available from the Energy Yearbook.

Construction Sector: Energy consumption data for the Construction sector are not available. Main energy consuming activities of the Construction sector are believed to be the construction of roads followed by construction of buildings. The energy intensity of Construction sector in some Asian countries in Mcal/US$ of 1992–93 (based on data of 1980s) are: Philippines 0.24, Thailand 0.42 and Republic of Korea 0.76 [53, 54 and 61].

Assuming an average energy intensity value of 0.5 Mcal/US$ for Pakistan, with Construction sector value added in 1992–93 of US $ 1919 million, the 1992–93 Construction sector energy consumption amounts to about 90,000 TOE. Further, it is assumed that 99.5% of Construction sector energy is consumed in the form of HSD and 0.5% in the form of electricity. The estimated Construction sector HSD consumption has been deducted from that of the Transport sector.

Mining Sector: Energy consumption data, for the mining activities are not available and are included in the Industrial sector. However, for its annual Census of Mining Industries, the Federal Bureau of Statistics (FBS), inquires about the quantities of various mineral productions and the corresponding fuel consumption from the mining lease holders. The energy consumption in the major mining activities (i.e. crude oil, natural gas, coal, lime stone and rock salt production) for the year 1988–89 has been compiled from the FBS questionnaires. These data have been used to estimate the energy use per ton of various mineral productions in the year 1988–89.

Using these information together with the data on the quantities of various mineral productions cited in the Pakistan Energy Year Book 1993 and Pakistan Statistical Year Book 1992 & 93, the total energy use by the Mining sector in the year 1992–93 has been estimated. (Small mining sub-sectors which together had only about 2% share in the value added of Mining industry during the year 1988–89 were left out in the above estimation process). The total energy consumption of the mining sector in years 1988–89 and 1992–93 has been estimated as 28,700 TOE and 55,300 TOE, respectively.

It may be mentioned here that most (more than 60 percent) of the energy consumption in the mining sub-sector in Pakistan is due to crude oil production. For crude oil the estimated energy consumption is 0.006 TOE/ton, which is comparable with the figure of 0.004 TOE/ton reported for Malaysia [99].

Manufacturing Sector: Oil consumption data for 1992–93 are available for total Manufacturing sector [14] and also separately for cement industry [44]. For the year 1992–93 the total oil consumption by Manufacturing industry excluding that by cement industry was distributed among various component industries in proportion to the shares of these component industries in the corresponding industrial consumption of oil in 1987–88, as derived from the data given in the Census of Manufacturing Industries (CMI) and the Census of Small Households and Manufacturing industries.

Gas consumption data for 1992–93 are available for total Manufacturing and separately for fertilizer, cement and several other individual industries as reported by different gas supply companies The gas consumption listed against Miscellaneous industries in the data obtained from gas companies was distributed among paper and board industries, machinery and equipment industries and small household and manufacturing industries in the light of 1987–88 data reported in CMI and Census of Small Household and Manufacturing industries.

Coal is presently being used by only one type of manufacturing industry, viz. brick kiln industry. The year wise coal consumption data are available in various Energy Yearbooks. However, these data are believed to be underestimated as noted in various Planning Commission documents [e.g. Ref. 21]. In the light of the Planning Commission estimates, the coal consumption figures for industry have been increased by a factor of 1.5.

As per estimates of the Energy Wing of the Planning Commission the use of bagasse as fuel by sugar industry in 1990–91 was about 1.68 million TOE as against an estimated production for 2.65 million TOE of bagasse by the sugar industry. The same ratio of consumption to production (i.e. 63.3%) has been assumed for 1992–93.

In the light of the Survey and Census of Small Household and Manufacturing industries [100, 101] and Energy and Demand Forecast for WAPDA Power System [70] small scale industries have been judgementally allocated a share of 15% in grid supplied electricity to the Manufacturing sector in 1992–93. The grid supplied electricity to large scale industries in 1992–93 has been distributed among various component industries in proportion to their shares in electricity consumption by large industries in 1987–88 as reported in the CMI.

The data on self generated and co-generated electricity by various industries in 1992–93 have been estimated in the light of [48–50 and 102]. It is found that self generated and co-generated electricity together correspond to about 15% of the grid supplied electricity to the Manufacturing sector. Only about 29% of the electricity produced by in-house facilities is due to co-generation systems and the rest is produced by stand-alone self generating units, as estimated in the light of data given in [51]. Some 82% of the self and co-generated electricity is used in Basic materials industries while the rest (18%) is used in the Consumer goods industries.

Transport Sector: Electricity used in oil transportation through pipelines is not reported separately and is included in the Manufacturing sector. This electricity use has been estimated from specific electricity consumption of 0.0358 kW·h/ton-km reported in [52].

This sector in addition to fuels used for movement of freight and passengers also includes fuels used for military, government, international and miscellaneous uses, which comprise the miscellaneous sub-sector of transport in the MAED model. Miscellaneous sub-sector includes the motor spirit, HOBC, kerosene and HSD data of Other Government sector (of Energy Yearbook), LDO of Other Government and Transport sector and all the aviation fuels minus the fuel used by PIA for domestic transport as reported in [44].

Household and Services Sectors: Energy consumption data available for households and Services sectors are reliable for gas and electricity only. As for kerosene and LPG the consumers buy these fuels from the retailers and there is no account whether the fuel is intended for household use or for the Services sector. Further, some of the LPG is also consumed by transport vehicles. As such, consumption of these fuels in different sectors, as reported in the Energy Yearbook, has to be adjusted on the basis of additional information. For this purpose, reports [15, 58, 59 and 103] based on various surveys were used. A distribution of 69%, 28% and 3% has been assumed for kerosene between Household, Service and Transport sectors, respectively and of 60%, 25% and 15% has been assumed for LPG among Household, Service and Transport sectors respectively.

As is the case of most developing countries, in Pakistan there is a large fraction of energy supplied by non-commercial fuels (i.e. fuelwood, crop residues and animal wastes). Reliable information on the amount of consumption of these fuels is not available. However, based on a recent survey [15] the use of non-commercial fuels in urban and rural households has been estimated. The use of non-commercial fuels in the Service sector has not been considered primarily due to lack of availability of data and also because its magnitude is believed to be small.

Final energy consumption data for the base year as given in the Pakistan Energy Yearbook and as reconstructed for the MAED application are given in Tables A.6 and A.7 respectively. Table A.8 gives the final energy consumption in the base year according to the MAED model requirements

A.4. Estimation of Base Year MAED Parameters

The application of MAED model requires the determination of several parameters for the base year and then their projections for the selected future years. The number of such parameters is about 200. In the present study some additional variables have been considered for the projection of energy demand of Agriculture sector. In view of the large differences in the income and energy consumption patterns, the energy demand of households has been analysed and projected separately for rural and urban households, and then combined to get the energy consumption of all the households. Further, projection of energy consumption in some activities i.e. electricity used in transportation of oil through pipelines, non-energy oil products consumption in various sectors, feedstocks used in the fertilizer industry and kerosene used for lighting, has been made outside the model, due to either the inability or inflexibility of the MAED model in handling these activities. All the base year, and projected, parameters are given in Table B.6 of Appendix B.

Agriculture, Construction and Mining Sectors: The sectoral value added and the final energy consumption, in the base year, (see Tables A.3 and A.8) are used to estimate the energy intensities of motor fuels and specific uses of electricity for the Agriculture, Construction and Mining sectors.

Manufacturing Sector: Energy intensity of thermal uses is generally quite high in the Manufacturing sector. Due to the possibility of interfuel substitutions, technological developments and conservation management leading to efficiency improvements and possibility of co-generation of electricity, the thermal uses in Manufacturing sector are considered at the level of useful energy.

Table A.6. Commercial Final Energy Consumption (1992–93) as given in the Pakistan Energy Year Book

Energy Uses: **Unit: TOE**

Sector	M S	HOBC	Kerosene	H S D*	L D O	F Oil	Aviation Fuel	Total Oil Products	LPG**	Gas	Coal	Electricity	Total
Domestic			641,734					641,734	109,016	1,773,331	1,446	1,072,565	3,598,092
Agriculture					299,243			299,243				458,914	758,157
Transport	1,081,738	146,946	1,279	4,886,376	1,010	45,713	253,800	6,416,862		736		2,199	6,419,797
Industries				126,087	541	1,323,694		1,450,322		3,606,926	1,439,122	1,062,222	7,558,592
Commercial									36,339	335,228		190,000	561,566
Other Govt	17,277	8,395	17,393	132,050	286	24,363	173,764	373,528				186,009	559,537
Total	1,099,015	155,341	660,406	5,144,513	301,080	1,393,770	427,564	9,181,689	145,355	5,716,221	1,440,568	2,971,908	19,455,741

* HSD consumption for tractors in Agriculture sector is not separately available and is included in the Transport sector.
** 75% of total LPG is allocated in Domestic Sector and 25% in Commercial Sector

Non-Energy Uses:

1	Fertilizer Feed Stocks (Gas)	1,377,217	TOE	(60% of supplies to fertilizer)
2	Coke	653,887	TOE	
3	Oil	416,699	TOE	(Production+Imports-Exports)
4	Total	2,447,803	TOE	
5	Bunkers	176,386	TOE	

Table A.7. Final Energy Consumption Reconstructed for the Base Year (1992–93)

Energy Uses: **Unit: TOE**

Sector	M S	HOBC	Kerosene	H S.D	L D.O	F Oil	Aviation Fuel	Total Oil Products	LPG	Gas	Coal	Electricity	Total Comm *Fuels*	Total Non-Comm *Fuels*
Agriculture				1,450,184	299,243			1,749,427				458,914	2,208,341	
Construction				90,000				90,000				450	90,450	
Mining				53,088				53,088		635		1,571	55,294	
Manufacturing				72,999	541	1,323,694		1,397,234		3,606,291	2,158,683	1,050,882	8,213,090	2,078,810
Transport	1,081,738	146,946	1,279	3,346,192		43,759	240,116	4,860,030	21,803	736	496	11,518 **	4,894,583	
Misc. Transport	17,277	8,395	17,393	132,050	1,296	26,317	187,448	390,176					390,176	
Domestic			453,706 *					453,706	87,213	1,773,331	1,446	1,072,565	3,388,261	18,231,000
Service			188,028					188,028	36,339	335,228		376,008	935,603	
Total	1,099,015	155,341	660,406	5,144,513	301,080	1,393,770	427,564	9,181,689	145,355	5,716,221	2,160,625	2,971,908	20,175,798	20,309,810

Total including Non-Commercial fuels: 40,485,608 TOE

* Includes 402,210 TOE of kerosene consumption for lighting by non-electrified households.

** Includes 9319 TOE consumed in pipelines for petroleum transportation and 2199 TOE used in Traction.

Non-Energy Uses:

1	Fertilizer Feed Stocks (Gas)	1,377,217	TOE
2.	Coke	653,887	TOE
3.	Oil	416,699	TOE
4	Total	2,447,803	TOE
5	Bunkers	176,386	TOE

Table A.8. Final Energy Consumption in the Base Year (1992–93) According to MAED Model Requirements

Sector	Motor fuels		Electricity Specific Uses		Thermal Uses: Fossil direct heat		Thermal Uses: Electricity			Thermal Uses: Total	Coal/I O Specific Uses: Trains	Coal/I O Specific Uses: Coke	Feed Stocks	Non-Energy Oil	Total Commercial Energy		Non-Commercial	Grand Total
	MTOE	Pcal	MTOE	TWh	MTOE	Pcal	MTOE	TWh	Pcal	Pcal	MTOE	MTOE	MTOE	MTOE	MTOE	%	MTOE	MTOE
Agriculture	1 749	18 484	0 459	5 636			–	–		-	–		–	0 048	2 256	9 90		2 256
Construction	0 09	0 951	0 0005	0 006	–	–		–	–	–	–			0 190	0 281	1 23		0 281
Mining	0 053	0 561	0 002	0 019	001	0 011	–	–	–	0 011	–		–	–	0 056	0 25	–	0 056
Manufacturing	0 074	0 777	1 209*	14 845	7 089	74 902		–	–	74 902	–	0 658	1 377	0 033	10 440	45 8 2	2 079	12 519
–Basic material	0 038	0 401	0 561	6 886	5 234	55 302	–	–	–	55 302	–	0 658	1 377	0 033	7 901	75 6 8	–	7 901
Machinery & equipment	0 003	0 034	0 048	0 585	0 130	1 374				1 374			–	–	0 181	1 73		0 181
–Non-durable Goods	0 018	0 186	0 441	5 417	1 689	17 846	–	–	–	17 864	–	–	–	–	2 148	20 5 7	–	2 148
Miscellaneous	0 015	0 156	0 159	1 958	0 036	0 380	–	–	–	0 380	–	–	–	–	0 210	2 01	–	0 210
Transportation	5 229	55 250	0 012	0 147	–	–	–	–	–	–	0 044	–	–	0 144	5 429	23 8 2	–	5 429
Service		–	0 357	4 384	0 560	5 917	0 019	0 233	0 201	6 118					0 936	4 11	–	0 936
Household	–	–	1 07	13 139	2 316	24 471	0 003	0 037	0 032	24 503	–				3 389	14 8 7	18 231	21 620
Total	7 195	76 023	3 110	38 176	9 966	105 301	0 022	0 270	0 232	105 533	0 044	0 658	1 377	0 415	22 787	100	20 310	43 097

* Includes self generated and co generated electricity, estimated as 15% of the grid supplied electricity

Note 1 MTOE = 10 566 Pcal = 12 279 TWh

As no estimates of end-use efficiency of various fuels for thermal uses, in the Manufacturing sector were available, so based on [104], efficiencies of 80%, 70%, 60%, and 40% were assumed for gas, furnace oil, coal and bagasse, respectively, giving an average efficiency of 65% in the base year.

Information about the distribution of useful thermal energy requirements of Manufacturing among furnace & direct heat, steam and space & water heating in Pakistani industries is not available. These distributions have been assumed in the light of information about the use of thermal energy in Manufacturing industries of some developing countries i.e. (Republic of Korea and Thailand) for which such information was available in the literature [53, 54].

For the derivation of MAED parameters related to co-generation the ratio of heat/electricity in the output of co-generation systems has been assumed as 3:1 in line with [55]. The efficiency of co-generation has been assumed as 70% and that of self generation has been assumed as 30%.

All the steel production is assumed to be based on the blast furnace process as the data available in published literature corresponds to only the Pakistan Steel Mills, Karachi. Coke input in blast furnaces per unit output of pig iron (EICOK) and specific consumption of pig iron in non-electric steel works (IRONST) have been worked out on the basis of 1992–93 data of steel production, pig iron production and coke consumption.

Transport Sector: The fuels used in the Transport sector in the base year are given in Table A.9 It may be noted that road transport accounts for about 84% of this consumption.

Table A.9. Fuels Used in the Transport Sector (1992–93)

[000 TOE]

	Railways	Airplanes	Road	Pipelines	Miscellaneous Transport	Total
Aviation Fuels		240.1			187.4	427.6
Motor Spirit			1081.7		17.3	1099.0
HOBC			146.9		8.4	155.3
Kerosene			1.3		17.4	18 7
HSD	158.4		3187.8		132.1	3478.3
LDO					1.3	1.3
Furnace Oil	43.8				26.3	70.1
LPG			21.8			21 8
Gas (CNG)			0.7			0.7
Coal	0.5					0.5
Electricity	2.2			9.3		11 5
Total	204 9	240.1	4440.2	9.3	390.2	5284.8
Share	3.9%	4.5%	84.0%	0.2%	7.4%	100%

Based on the 1992–93 data of transport vehicles on road and the information contained in [56], about the shares of urban and intercity vehicles, load factors and vehicle-km per year by type of vehicle, the intercity and intracity passenger-km and ton-km were estimated for 1992–93 (see Table A.10). As the 1992–93 activity levels for intercity passenger-km and ton-km were available the estimated intercity vehicle-km were accordingly adjusted. Then based on estimates of average fuel consumption by various types of vehicles on level roads in Pakistan reported in [56], the fuel used by public and private passenger vehicles and freight vehicles was estimated for intracity and intercity transportation activities. The estimated diesel and gasoline consumption were about 13% and 15% lower than the respective fuel use given in Table A.9 (see Table A.11).

As the MAED model considers only six types of road vehicles i.e. intercity and intracity cars, buses and trucks all the vehicles were grouped into intercity and intracity effective cars (comprising car, taxi, jeep, rickshaw and motor cycles), effective buses (comprising buses, minibuses, wagons and pick-ups) and effective trucks (comprising conventional trucks, truck trailers and delivery vans). Then by an iterative process, various MAED related parameters were judgementally derived for effective cars, buses and trucks.

Most of the MAED parameters for railways are directly derivable from the data given in [57]. However, some parameters e.g. energy intensity of diesel freight trains (DTRAF) and of diesel passenger trains (DTRAP) had to be estimated from historical data of fuel used by diesel freight and passenger trains, train-km and ton-km. Table A.12 gives the reconstructed fuel consumption in the Transport sector.

Household Sector: A recent survey [15, 58 and 59] gives details of the use of commercial as well as non-commercial fuels in urban and rural households by type of activity. Based on these estimates the energy consumption data for the Household sector were dis-aggregated into rural and urban households by type of activity (i.e. cooking, water heating and space heating). However, for rural households the thermal use of energy was not dis-aggregated into different activities because of the fact that rural households mainly use non-commercial fuels which are neither suitable for indoor space heating nor for hot water supply, as concluded by [15].

As for electricity, its use in households has been increasing at very high rates (12–16%) in recent years, both due to increase in number of electrified houses and increase in electricity consumption by already electrified houses with increasing incomes. The ownership of electrical appliances is significantly different in urban and rural households resulting in quite different consumption pattern in the two categories of households. For example, lighting is the dominant component (42%) of electricity consumption in rural households whereas electrical appliances (without including electric fans) are the highest contributors to the electricity consumption of urban households. In view of these aspects, the electricity consumption by the two categories of households has been dis-aggregated into four types of activities viz. lighting, air cooling, air conditioning and other appliances. This dis-aggregation has been done in the light of information available from [58]. Since the MAED model does not allow for such a dis-aggregation, the input parameters of the model were also worked out on the whole country basis by aggregating the above information. Nevertheless, the dis-aggregated information has been used outside the model for projecting the future electricity consumption and then incorporating the results into MAED by suitably adjusting its parameters in future years. This dis-aggregation also facilitates the analysis of conservation and efficiency improvement policies.

Table A.10. Road Transport Fleet Capacity Analysis (1992–93)

	Utilization		Urban Rural Split		Vehicles on Road			Fleet Capacity (Pass-Km/Ton-Km)		
	Km/a	Load Factor (Pass./Ton)	Urban (%)	Intercity (%)	Urban	Intercity	Total	Urban (million)	Intercity (million)	Total (million)
I Pass. Traffic										
A: Bus										
1 Bus	65000	43.7	24	76	9508	30108	39616	27007	85523	112530
2 Mini Bus	55000	18	62	38	7462	4573	12035	7387	4527	11914
Sub total					16969	34682	51651	34394	90050	124444
B: Motor car										
3 Wagon	50000	12	11	89	10786	87267	98053	6471	52360	58832
4 Pick-up	25000	8	13	87	5075	33960	39035	1015	6792	7807
5 Taxi	30000	3	100	0	39131	0	39131	3522	0	3522
6 Car	14000	3	60	40	332944	221963	554907	13984	9322	23306
7 Jeep	14000	3	60	40	24005	16004	40009	1008	672	1680
Sub total					411941	359194	771135	26000	69147	95147
C: Others										
8 Rickshaw	30000	2	100	0	44071	0	44071	2644	0	2644
9 Motorcycle	10000	1	90	10	1049842	116649	1166491	10498	1166	11665
Sub total					1093913	116649	1210562	13143	1166	14309
Passenger total							2033348	73537	160364	233901
Share (%)								31.4	68.6	100
II Freight Traffic										
10 Conv. Truck	75000	5.68	10	90	10498	94484	104983	4472	40250	44723
11 Truck Trailer	65000	16	0	100	0	4374	4374	0	4549	4549
12 Delivery Van	40000	0.5	100	0	91015	0	91015	1820	0	1820
Freight total					101513	98859	200372	6293	44800	51092
Share (%)								12.3	87.7	100
Total							2233720			

Table A.11. Fuel Consumption in Road Transport (1992–93)

	Intercity Vehicle-Km (million)	Adjusted Vehicle-Km (million)	Intercity Av Fuel Use (Lit /000 Km)		Intercity Fuel Use (Million Litre)		Urban Vehicle-Km (million)	Urban Av Fuel Use (Lit /000 Km)		Urban Fuel Use (Million Litre)		Total Fuel Use (Million Litre)	
			HSD	Gasoline	HSD	Gasoline		HSD	Gasoline	HSD	Gasoline	HSD	Gasoline
I Pass. Traffic													
A: Bus													
1 Bus	1957	1648	220	0	362	0	618	220	0	136	0	498	0
1 Mini Bus	252	212	150	0	32	0	410	150	0	62	0	93	0
Sub total	2209	1859			394	0	1028			198	0	592	0
B: Motor car													
3 Wagon	4363	3673	100	0	367	0	539	100	0	54	0	421	0
4 Pick-up	849	715	90	0	64	0	127	90	0	11	0	76	0
5 Taxi	0	0	0	90	0	0	1174	0	90	0	106	0	106
6 Car	3107	2616	0	90	0	235	4661	0	90	0	420	0	655
7 Jeep	224	189	90	0	17	0	336	90	0	30	0	47	0
Sub total	8544	7193			449	235	6837			96	525	544	761
C: Others													
8 Rickshaw	0	0	0	33	0	0	1322	0	33	0	44	0	44
9 Motorcycle	1166	982	0	25	0	25	10498	0	25	0	262	0	287
Sub total	1166	982			0	25	11821			0	306	0	331
Passenger total	11919	10034			843	260	19686			293	831	1136	1091
Share (%)													
II Freight Traffic													
10 Conv Truck	7086	5853	300	0	1756	0	787	300	0	236	0	1992	0
11 Truck Trailer	284	235	420	0	99	0	0	420	0	0	0	99	0
12 Delivery Van	0	0	0	90	0	0	3641	0	90	0	328	0	328
Freight total	7371	6087			1854	0	4428			236	328	2091	328
Share (%)													
Total	19290	16121			2697	260	24114			529	1159	3227	1419
				(000 TOE)	2330	195			(000 TOE)	457	868	2788	1063

Table A.13 provides information about some key aspects of energy use in urban and rural households together with country averages for the base year.

Service Sector: In the case of Service sector, MAED requires only aggregated information about thermal uses, but dis-aggregated information on electricity consumption split among uses for air-conditioning, space heating and other appliances. This dis-aggregation was done in the light of information available from [36].

Table A.12. Reconstructed Fuel Use from MAED for Transport Sector (1992–93)

[MTOE]

Activity	Motor Fuel	F.O + Coal	Electricity	All Fuels	Share [%]
Transport					
– Freight	2.407	0	0.001	2.408	45.6
– Intercity Passengers	1.409	0.044	0.002	1.455	27.6
– Urban Passengers	1.022	0	0	1.022	19.4
	4.839	0.044	0.007	4.889	
Misc Transport	0.390	0	0	0.390	7.4
Total	5.229	0.044	0.002	5.275	100

Table A.13. Main Parameters For Household Sector Energy/Electricity Demand Assessment (1992–93)

PARAMETER	RURAL	URBAN	TOTAL COUNTRY
Fraction of dwellings in areas where space heating is required (DWSH)	100%	100%	100%
Fraction of pre-1993 dwellings with room heating only (PREDW(J))	0	6.6	2.1
Specific space heat requirements of pre-1993 dwellings with room heating only [Mcal/dw/year] (SHDWO(J))	0	1866.5	1866.5
Share of dwellings with hot water (DWHW)	0	100.0%	31.5%
Specific energy consumption for water heating per person (useful energy [Mcal/person/year] (HWCAP)	0	43.95	43.95
Specific energy consumption for cooking in dwellings (useful energy) [Mcal/dw/year] (COOKDW)	1892.48	2434.93	2066.14
Share of electrified households (PEL)	44.8%	82.4%	56.8%
Electricity for lighting/electrified dwelling (kW·h/dw/year)	450	470	459.3
Electricity for cooling/electrified dwelling (kW·h/dw/year)	350	500	419.6
Electricity for other appliances/electrified dwelling (kW·h/dw/year)	280	655	454.0
Specific (final) electricity consumption per dwelling for uses other than space/water heating, cooking and ACs (ELAPDW)	1080	1625	1328.5
Share of dwellings with ACs (DWAC)	0.44%	2.3%	1.04%
Specific cooling requirements per dwelling [Mcal/dw/year] (ACDW)	4395.9	4395.9	4402.1
Kerosene for lighting/non-electrified household [Mcal/dw/year]	56.92	55 19	55 42

* COOKDW for Rural Households represents all thermal energy uses.

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Appendix B

PROJECTION OF MAED PARAMETERS

B.1. Projections of MAED Parameters in Reference Scenario

B.1.1. Demographic Parameters

For the Reference scenario the urban–rural split has been worked out in line with historical trends and the 8th Five Year Plan's perspective on urbanization. Similarly, the share of population living in large cities has been estimated in view of past trend. Household sizes in the rural and urban areas are essentially extrapolation of past trend. Potential labour force is projected in line with overall population growth. The labour force actually employed has been projected till the year 2008 on the basis of official targets for creation of employment, while for the remaining period this parameter has been extrapolated. All these parameters are listed in Table 3.1.

B.1.2. Agriculture Sector

Energy consuming activities considered in the Agriculture sector are use of farm machinery and water pumping. These activities are related to various parameters such as: cultivated area, irrigated area, surface and ground water availability, tractor population, average annual utilization of tractors and energy intensities of water pumps and tractors. These parameters have been projected in the light of historical trends, targets of the 8th Five Year Plan, availability of water resources and saturation limits of farm tractors.

Cultivated area in Pakistan has increased by about 0.5% p.a. during the last 30 years. It is assumed that during the 8th Plan period (1993–98) cultivated area will increase at annual growth rate of 0.5% and this growth rate will decrease gradually to 0.25% per annum by the end of the study period.

B.1.2.1. Energy demand for farm machinery (tractors)

The tractor population has been increasing very rapidly in the past. In 1973 there were only 0.2 tractors per thousand acres of cultivated land and these increased to 6.5 by 1992–93. The tractor population itself has increased by a factor of 37 and was 337 thousand in 1992–93. It is projected that tractor population per thousand acres will increase by a factor of 2.5 during the planning horizon of 30 years with gradually declining annual growth rates i.e. from 5% p.a. during the period 1993–98 to 2% p.a. during the period 2018–2023. This declining growth rate has been assumed judgementally but is in-line with the Energy Wing's tractor population growth rate assumption of 2.8% per annum during 1991–2018 [29].

The average utilization of tractors is assumed to decrease gradually from 995 hours in the base year to 850 hours by the year 2022–23 as a result of increase in tractor population. It is assumed that the energy intensity of an average tractor, about 5 liters/hour in 1992–93 [41], will improve by 10% during the 30 years planning horizon to 4.5 liters/hour.

On the basis of these assumptions the motor fuel requirements for tractors will increase by an average growth rate of 2.6% p.a. i.e. from 1.53 million TOE in 1992–93 to 3.35 million TOE by the year 2022–23 (Table B.1).

B.1.2.2. Energy demand for water pumping

During the period 1963–93, the share of irrigated area in total cultivated area has increased from 61.1% to 80.7% and 8th Five Year Plan target is 81.9%. It is assumed that this share will steadily increase to 87% by the year 2022–23.

Water availability, during the last 20 years, has increased by 0.8% p.a. and the Planning Commission is envisaging 0.6% p.a. growth during the 8th Five Year Plan period. In the base year, water availability per irrigated acre was 2.98 feet and by assuming the 8th Plan target it will be 3.05 feet per acre in the year 1998. This value has been assumed to be the saturation limit, keeping in view the total water availability potential of the country as reported in the Pakistan National Conservation Strategy [105]. Surface water availability has been growing by 1.3% per annum during the last 20 years and for the next five years it is assumed that its annual growth will be 0.83% and its value will increase from 78.64 Million Acre Feet (MAF) in the base year to 8th Plan target of 81.95 MAF in the year 1998. It has been assumed that the surface water availability will increase up to 97.0 MAF in the year 2022–23 and the remaining water requirements will be fulfilled by pumping of underground water.

Underground water is being pumped by electric and diesel pumps. However, with the expansion of the rural electrification programme the share of electric pumps is increasing. The share of electricity in total useful energy of water pumping has been assumed to increase from 85% in 1992–93 to 97% by 2022–23. The energy consumption to pump an acre–foot of water has increased by 0.9% p.a. during the period 1973–1993 as a result of drop in water table. It is assumed that this trend will continue in the future and energy intensities of water pumps will increase with a growth rate of about 1% per annum. As a result of the above mentioned assumptions the total useful energy requirements for water pumping will increase from 0.15 million TOE to 0.24 million TOE which shows annual growth of 1.7% (Table B.1). The electricity demand in Agriculture sector will increase by 49% from 0.45 million TOE to 0.67 million TOE, while motor fuel demand for water pumping will decrease from 0.30 million TOE to 0.07 million TOE by the year 2022–23.

The total energy demand of agriculture sector is also given in Table B.1 and the changes in energy intensities are given in Table B.6, which shows that the energy intensities for motor fuel and electricity will decrease by about 47% and 58% respectively in the terminal year with respect to base year.

B.1.3. Construction sector

Since no historical data are available for energy consumption of the Construction sector, projections for this sector have been done in the light of the experiences of other countries [53, 54 and 61]. It is assumed that the energy intensity for motor fuels will gradually increase to 1.75 times of base year value in 2022–23. Presently, a small quantity of electricity is being consumed in Construction sector. However, keeping in view the data of some developing countries, it is assumed that electricity will penetrate by an average growth rate of10% p.a. during the period of next thirty years. With this assumption, electricity intensity will be 2.01, 3.54, 5.71, 8.78, 13.21 and 19.41 with respect to base year in 1998, 2003, 2008, 2013, 2018 and 2023 respectively.

Table B.1. Energy Demand Projections for Agriculture Sector (Reference Scenario)

Water Pumping

Year	Cultivated Area ARLAND (million acre)	Fraction of irrigated area to cultivated area FIRRIG (fraction)	Water Availability per - irrigated acre WRIL (feet)	Total irrigation water requirements TWRI= ARLAND* FIRRIG*WRIL (Million acre feet)	Surface water availability at farm gate WAFG (Million acre feet)	Total ground water requirements for irrigation TGWRO= TWRI-WAFG (Million acre feet)	Energy intensity for water pumping EPUMPI (10^3 Kcal/AF)	Total energy requirements for water pumping (useful) TEGWP= TGWRO* EPUMPI (Tcal)	Fraction of total useful energy in pumping FDWP (fraction)	Useful energy requirements for water pumping: Motor fuel MFPUMPU= TEGWP * FDWP (Tcal)	Useful energy requirements for water pumping: Electricity ELAGRKU =TEGWP * (1-FDWP) (Tcal)	Efficiency of Pumps: Diesel EFFDPUMP (fraction)	Efficiency of Pumps: Electric EFFEPUMP (fraction)	Final energy requirements for water pumping: Motor fuel MFPUMPF= MFPUMPU/ EFFDPUMP (Pcal)	Final energy requirements for water pumping: Electricity ELAGRKF= ELAGRKU/ EFFEPUMP (Pcal)
1993	52 117	0 807	2 975	125 12	78 64	46 48	33 068	1537 13	0 148	227 817	1309 309	0 072	0 27	3 164	4 849
1998	53 430	0 819	3 045	133 25	81 95	51 30	34 756	1782 87	0 120	213 994	1568 923	0 079	0 29	2 708	5 410
2003	54 650	0 838	3 05	139 68	85 00	54 68	36 527	1997 29	0 102	203 724	1793 570	0 085	0 31	2 397	5 786
2008	55 750	0 850	3 05	144 53	88 00	56 53	38 391	2170 32	0 084	182 306	1988 009	0 090	0 32	2 026	6 213
2013	56 800	0 860	3 05	148 99	91 00	57 99	40 349	2339 69	0 066	154 20	2185 273	0 094	0 33	1 643	6 622
2018	57 590	0 865	3 05	151 94	94 00	57 94	42 409	2457 04	0 048	117 938	2339 104	0 097	0 34	1 216	6 880
2023	58 310	0 870	3 05	154 73	97 00	57 73	44 570	2572 83	0 030	77 185	2495 644	0 100	0 35	0 772	7 130

Tractors

Year	Tractor population per thousand acres of arable land TRACT (Tractors/ 1000 Acre)	Annual use of a tractor HTRACT (hours/year)	Hourly fuel consumption of a tractor DTRACT (Mcal/ Tractor/hour)	Motor fuel requirements for tractors MFTRAC= ARLAND *(TRACT/1000) *HTRACT *DTRACT/1000 (Pcal)
1993	6 4748	994 8	45 645	15 323
1998	8 26	950	44 884	18 818
2003	10 05	920	44 123	22 295
2008	11 76	895	43 362	25 444
2013	13 38	875	42 601	28 329
2018	14 91	860	41 841	30 898
2023	16 46	850	41 081	33 515

Total

Year	Total motor fuel requirements for agriculture MFAGR =MFPUMPF +MFTRAC (Pcal)	Electricity requirements for water pumping ELAGRKF (Pcal)
1993	18 487	4 849
1998	21 526	5 410
2003	24 692	5 786
2008	27 470	6 213
2013	29 972	6 622
2018	32 113	6 880
2023	34 286	7 130

Source. Based on [7, 8, 10, 41, 42 and 105]

B.1.4. Mining sector

Energy intensities for the Mining sector have been projected in the light of historical estimates, while keeping in view the potential of different sub-sectors, such as coal mining, oil and gas extraction etc. It is assumed that the electricity intensity will remain constant during the planning study period. The intensity of motor fuels use in this sector has been assumed to increase by a factor of 1.25 in the first period which gradually increases up to 2.50 in the last period with respect to the base year.

B.1.5. Manufacturing sector

The factors determining the change of energy demand in the Manufacturing sector include changes in sub-sectoral contributions in value added of Manufacturing sector, changes in energy intensities and efficiencies and penetration of new energy sources and technologies. The sub-sectoral changes in value added of total Manufacturing sector are discussed in Section 3.3.1 (see Tables 3.6 and 3.7).

During the last ten years the intensity of thermal uses has decreased by about 16%, while the intensity of specific electricity uses has increased by 19% (see Table 4.7). In the case of motor fuels the trend is not very clear due to relatively small quantities of the fuel used so motor fuel intensity has been assumed to remain constant. The reduction in intensity of thermal uses is believed to be the result of energy conservation and technological improvements over this period, while the increase in the intensity of electricity is an effect of higher automation in Manufacturing sector. In line with the historical trend it has been assumed that the energy intensity for thermal uses will decrease by 25% and for electricity it will increase by 15% by the end of the 30 year planning period.

The end-use efficiency of substitutable fossil fuels for the thermal uses is assumed to improve from 65% in 1992–93 to a value of 72.5% in the terminal year of the study. These improvements are expected in view of technological improvements and interfuel substitution.

A modest penetration of solar energy in low and medium temperature heat requirement is assumed. For low temperature heat this penetration is assumed from the third period of the study (i.e. from the year 2003) while for the medium temperature heat this penetration is assumed from the fourth period. Keeping in view the recent trend in manufacturing sector for better utilization of energy resources, it is supposed that the share of co-generated heat in low temperature steam demand will increase from 17.7% in the base year to 25% in the year 2022–23. Penetration of district heat is not considered.

B.1.5.1. Feedstocks

The requirement of coke per ton of steel production is assumed to decrease from 905 kg in 1992–93 to 700 kg in 2022–23. This envisaged reduction is based on the assumption that in future more efficient plants will be set up in the country as are being used by other countries e.g. (a) India envisaged a reduction from 780 kg/ton in 1986 to 560 kg/ton in 2009 [106] and (b) West European countries have projected a decline from 520 kg/ton in year 1975 to 400 kg/ton in the year 2000 [107]. It is assumed that steel conversion from pig iron will remain constant at 1.05 ton of pig iron per ton of steel .

The MAED model computes the fertilizer feedstocks requirements using a linear relationship to the value added of the basic materials, but the fertilizer requirements depend upon various other factors such as the area under crops, cropping intensity, crop pattern and irrigation levels. Hence the feedstocks requirements are calculated manually outside the model. Based on historical data it is assumed that the feedstocks requirement will increase with declining growth rates i.e. from a growth rate of 10% p.a. during 1993–98 to 0.78% p.a. during the period 2018–2023. The feedstocks requirements will increase from 1.38 million TOE in 1992–93 to 4.37 million TOE in the year 2022–23. The fertilizer consumption in Pakistan envisaged for 2022–23 will correspond to a consumption of 288 nutrient kg N/hectare of cultivated area (see Table B.2).

Table B.2. Projections of Fertilizer Feedstocks and Comparison with some other Countries

1. Projection of Fertilizer Feedstocks

Year	1992–93	1997–98	2002–03	2007–08	2012–13	2017–18	2022–23
(million TOE)	1.377	2.217	2.967	3.541	3.940	4.203	4.370
Growth Rates		10.0%	6.0%	3.6%	2.16%	1.30%	0.78%
Ratio of 2023 feedstocks to 1993 feedstocks				3.17			

2. Fertilizer Consumption in Pakistan

	1992–93	2022–23
Fertilizer consumption (kg/ha)	91	288 (3.17 times of 1993)

3. Fertilizer Consumption in Relation to Cultivated Area in some Selected Countries (1991–92)

Year	Country	Fert. Consumption (kg/ha)
1992	Netherlands	599
1991	Germany	394
1992	Japan	431
1992	France	309
1992	Egypt	405
1992	Italy	220
1992	USA	71
1992	USSR	85
1992	India	77

Source: [10]

B.1.5.2. Non-energy petroleum products

The Non-energy petroleum products have been divided into three categories i.e. lube oil, asphalt and "others" (i.e. carbon oil, MTT, BTX etc.). Lube oil is mainly consumed in transport and agriculture sectors and major consumer of asphalt is Construction sector while the "others" are mainly consumed in the Manufacturing sector. Historical data (Table B.3) shows that the consumption of lube oil, over the years, has remained more or less constant at about 3% of the fossil fuels used in Transport and Agriculture sectors. It is assumed that the lube oil will maintain a 3% ratio to the total motor fuel demand of Transport and Agriculture sectors. Table

B.3 also shows that the energy intensity of asphalt consumption, during the period 1976–1993, remained in the range of 3.0–5.0 tonnes per million Rs. of Construction sector value added and during the same period energy intensity of "others" non-energy oil products were in the range of 0.16 – 0.45 tonnes per million Rs. of Manufacturing sector value added. In the light of historical data it is assumed that, over the next three decades, the demand for asphalt and "other" non-energy oil products will be 4.0 tonnes and 0.2 tonnes per million Rs. of Construction sector and Manufacturing sector value added respectively.

B.1.6. Transport sector

Base year values of the Transport sector parameters and their projected values for the Reference scenario are given in Table B.6. The following paragraphs describe the basis for the projection of these parameters.

B.1.6.1. Freight transportation

Freight transportation activity has increased by a factor of three during the past two decades, i.e. from a level of 18 billion ton-km in 1973 to 53 billion ton-km in 1992–93. However, during the past 15 years the ton-km growth rates have been declining, i.e. 8.1% p.a. during 1978–83, 7.5% p.a. during 1983–88 and only 2.7% p.a. during 1988–93 (see Table A.5). Freight transportation activity levels are projected on the basis of a linear equation linking freight ton-km with the sum of the value added of the Agriculture, Mining, Manufacturing and Energy sectors. The constant (CTFRT(1)) and slope (CTFRT(2)) of the linear equation were determined by fitting a straight line equation to 1992–93 data and 8th Plan target for 1998. Projected growth rates of ton-km for the period 1993–98, 1998–03, 2003–08, 2008–13, 2013–18 and 2018–23 are 3.9% p.a., 4.4% p.a., 4.9% p.a., 5.4% p.a., 6.0% p.a., and 6.5% p.a. respectively with the average for the 30 years period being 5.2% p.a.

During the last two decades the share of trains in freight transportation has been declining while the share of trucks (intercity and local) has been increasing. The share of oil pipelines, since 1981, has increased from less than 1% to about 6% by 1992–93. Table A.5 also shows the historical evolution of the shares of different modes in total freight transport.

The projected 1998 shares of intercity trucks, freight trains and pipelines in the freight transport reflect the Eighth Plan targets. It is assumed that the share of urban trucks in road freight transport will be the same in 1998 as in the base year. As the declining share of railways would involve extra costs to the economy, the Sixth and Seventh Plans aimed at reversing this trend, however, this was not achieved. The Eighth Plan, without assigning any target, also envisages increasing the share of the railways. A share of 31.5% for railways and 47.3% for intercity trucks by 2022–23, has been assumed keeping in view the Seventh Plan targets for 2005–06. (These shares correspond to shares of 40% and 60% for railways and intercity trucks respectively between these modes only). The shares of local trucks and pipelines have been judgmentally assumed to remain constant at about 11% and 10% respectively in the period beyond 1998. The share of local trucks in total truck freight transportation is expected to increase from about 14.5% in 1992–93 to 19.1% by 2022–23. The steam freight trains are assumed to be completely phased out by 2008. The share of electric trains in freight transportation by trains has been judgmentally assumed to increase from 3% in 1992–93 to 16% by 2022–23 in view of the proposals for electrification of various sections of the railways [56]. Figure 4.1 shows the historical and projected shares of trucks, trains and pipelines in freight transport.

Table B.3. Non-Energy Petroleum Products

Year	Lubes (Tonnes)	Fossil Fuels Consumption in Transport + Agriculture (TOE)	Tonne of Lubes per TOE of Fossil Fuels Consumption in Transport + Agriculture	Asphalt (Tonnes)	GDP of Construction Sector (million Rs.)	Tonne of Asphalt per million Rs. of GDP of Construction	Others (Carbon oil etc.) (Tonnes)	GDP of Manufacturing Sector (million Rs.)	Tonne of Others per million Rs. of GDP of Manufacturing
1972–73	6,958	2,320,346	0.003	83,807	13,649	6.1	16,321	53,601	0.30
1973–74	7,629			90,203	15,109	6.0	17,513	57,018	0.31
1974–75	94,132			116,586	17,786	6.6	25,239	57,421	0.44
1975–76	91,750			78,316	21,234	3.7	18,448	58,312	0.32
1976–77	88,258			76,950	21,052	3.7	19,984	59,462	0.34
1977–78	77,264	2,948,033	0.026	90,104	22,796	4.0	29,337	65,501	0.45
1978–79	110,385			95,270	24,043	4.0	19,640	70,755	0.28
1979–80	128,211			112,461	26,811	4.2	24,268	77,972	0.31
1980–81	124,476			117,567	27,876	4.2	30,696	86,209	0.36
1981–82	113,009			115,429	29,454	3.9	40,340	97,935	0.41
1982–83	133,587	4,100,538	0.033	119,326	28,656	4.2	33,150	104,859	0.32
1983–84	136,503	4,257,765	0.032	120,843	28,932	4.2	25,377	113,142	0.22
1984–85	149,355	4,412,328	0.034	153,350	31,651	4.8	31,014	122,305	0.25
1985–86	172,145	4,692,091	0.037	169,750	33,768	5.0	23,205	131,567	0.18
1986–87	149,981	4,875,856	0.031	164,634	37,977	4.3	37,737	141,502	0.27
1987–88	162,283	5,326,346	0.030	173,704	39,851	4.4	38,060	155,566	0.24
1988–89	169,283	5,469,078	0.031	164,362	40,751	4.0	35,503	161,916	0.22
1989–90	185,832	5,902,584	0.031	144,617	42,024	3.4	38,971	171,309	0.23
1990–91	191,384	5,976,957	0.032	163,852	44,420	3.7	35,534	182,123	0.20
1991–92	191,443	6,845,296	0.028	139,575	47,076	3.0	36,931	196,798	0.19
1992–93	192,944	7,420,152	0.026	190,305	49,807	3.8	33,450	207,568	0.16

Sources: [10, 14]

The energy intensities of the freight trains, intercity trucks and urban trucks are assumed to decline gradually and reach a level of 90% of the base year values. As at present the main oil pipeline is being used for transporting HSD and kerosene only and the planned pipeline projects include crude oil and furnace oil pipelines so it is assumed that energy intensity of the pipelines will gradually increase from 30.8 kcal/ton-km in 1992–93 to a level of 35.0 kcal/ton-km by 2022–23.

B.1.6.2. Intercity passenger transport

Intercity passenger travel has increased by a factor of 3 during the past two decades i.e. from a level of 52 billion passenger kilometer (PKM) in 1973 to 155 billion PKM in 1992–93 (see Table A.4). However, during the last 15 years the intercity PKM growth rates have been declining i.e. 6.8% p.a. during 1978–83, 5.6% p.a. during 1983–88 and only 3.5% p.a. during 1988–93. JICA study of 1988 had projected the intercity (rail and road) passenger-kilometers to increase by 4.4% p.a. during the period 1986–2000. It has been assumed that intercity passenger travel will increase by 3.5%, 4.0% 4.5%, 5.0% and 5.5% p.a. during the 1998–03, 2003–08, 2008–13, 2013–18 and 2018–23 periods respectively. These activity levels have been used to project the average annual intercity travel distance per person (DI). The value of DI increases by a factor 1.77 during the next 30 years.

In 1992–93 the number of cars and jeeps on road in Pakistan was about 594 thousand, giving a value of about 200 persons per car. It is envisaged by the Planning Commission that by 2018 there may be 50 persons per car [8]. It may be noted that in 1990 the number of persons per car in Argentina, Malaysia, Brazil and Republic of Korea were 8, 10, 14 and 21 respectively [27]. It has been assumed that the Planning Commission assumption would also apply to "Effective Cars", and the parameter CO has been projected accordingly. Hence the number of persons per "Effective Car" will decline from 115 in 1992–93 to 22 by 2022–23. Based on [28], a growth rate of 1% p.a. was judgmentally assumed in the average annual distance driven per car in intercity travel. Shares of buses and airplanes in intercity passenger travel (excluding cars) have been increasing with time while the share of railways has been declining. For 1998 the shares of different transportation modes have been projected in the light of 8th Plan targets. For the period beyond 1998 it has been assumed that the share of railways will remain constant at 12%, the share of travel by bus will decline slightly and the share of air travel will increase correspondingly. Figure 4.2 shows the historical and projected shares of planes, trains and buses in intercity passenger transport excluding cars. Further, it is assumed that steam trains will be completely phased out by 2008 and the share of electric trains in railways will increase with time, in the period beyond 1998.

It has been assumed that number of persons per bus (LFBU) and number of persons per train (LFTRA) will decline gradually with time to reflect improvements in the quality of service. For, airplanes the load factor of 0.65 has been assumed to remain constant throughout the next 30 years. The energy intensities of intercity car, bus, train and airplane have been assumed to decline by 10% by the year 2022–23.

B.1.6.3. Urban passenger transport

The urban passenger transport activity level i.e. passenger kilometers (PKM) is related to the size of population living in large cities, city size, disposable income of the city dwellers and social factors. Urban PKM statistics are not published regularly in Pakistan, however, one such estimate has been made by JICA for 1986 [56]. The urban PKMs for 1992–93 have been estimated based on JICA assumptions of 1986. The growth rate of urban PKMs during 1986–93 has been approximately 6% p.a. The population of large cities (having population greater than half million) is estimated to have grown by about 5.3% p.a. during the 1981–93 period. This indicates that DU (average daily travel distance per person in large cities) may be expected to increase at around 1% p.a. A growth rate of 1% p.a. has been assumed for the value of DU, because the value of 10 km per person per day in 2022–23 is within the range of 1975 values for this parameter for all regions, except North America , analysed in the study [26].

In urban passenger transport, the shares of "Effective Cars" and "Effective Buses" have been estimated as 35% and 65% respectively for the base year. At present there is no mass transit system in any large city of the country. It has been judgmentally assumed that the share of "Effective Cars" in passenger transport will increase to 45%. In view of the recently established Mass Transit Authority which plans to build mass transit systems in Karachi, Lahore, Faisalabad and Islamabad/Rawalpindi it is expected that some electricity based mass transit systems (such as electric railways and/or electric trams) will be established in future. A share of 10% has been judgmentally assigned to electric mass transit systems (UMTE) in 2022–23. The energy intensity of "Effective Urban Cars" and "Effective Urban Buses" is projected to decline gradually from base year values by 10% in the year 2022–23.

B.1.6.4. Miscellaneous transport

The fuel use in miscellaneous transport activities has been projected on the basis of regression of fuel consumption by this sub-sector with total GDP using 1987 to 1992–93 data. The projected growth rates of fuel demand are 2–3% for 15 years and about 4–5% for the rest of the planning period.

B.1.7. Household Sector

The input parameters of MAED for Household sector are listed in Table B.6 along with the values for the base year and future years. The base year values have been worked out as explained in Section 4 of Appendix A. For the future years these values have been worked out from a detailed analysis involving rural–urban energy consumption patterns and a more dis-aggregation of end-use activities in this sector. Such a treatment helps in visualizing the future evolution of energy demand in the urban and rural households. This treatment was not possible in the MAED model, as such firstly the dis-aggregated parameters have been worked out and then these have been converted to MAED input parameters.

To project electricity demand in the Household sector, the extent of electrification has to be estimated at the first place. At present, only 57% of total households have access to electricity: 82% in the urban areas and 45% in the rural areas. The government is vigorously pursuing a rural electrification programme, and a target of 4000 villages per year during the 8th Five Year Plan has been set for electrification. Still at the end of 8th Plan period only 65% of the total households would be electrified. The government has also set a target of achieving 100% electrification by the year 2008. It has been observed that when the electric grid is extended to a village, not all the households get connections in the initial years. However, after a few years most of the households do get access to electricity. In view of this aspect and the rate of achievement in the past, it has been assumed that the 100% electrification level could be achieved by the year 2013.

The electricity consumption in the Household sector has been broken down into four different end-use categories, viz. lighting, air cooling, air conditioning and other appliances. In the base year, the lighting activity has been estimated to account for 468 kW·h and 448 kW·h per year per electrified household in the urban and rural areas respectively. Keeping in view electricity consumption for lighting in households with different income levels and that in other countries, a growth rate of 1.6% p.a. for the 1993–98 period, declining to 0.3% p.a. by the end of planning horizon has been assumed for future consumption of electricity for lighting per electrified household. Further, it has been assumed that the average efficiency of lighting devices will improve with time as a result of shift towards use of florescent tubes instead of incandescent bulbs. At present, on the average 1.67 incandescent bulbs and 0.41 florescent tubes per household are being used. It is envisaged that the use of florescent tubes will increase with time resulting in reduction in the average electricity consumption for lighting. On this account, it has been assumed that there will be about 15% reduction in the specific electricity consumption for lighting over the entire planning horizon in urban households and about 10% reduction in rural households. This would result in 665 kW·h consumption per year per urban household and 636 kW·h consumption per year per rural household by the year 2022–23.

Air cooling (fans and coolers) is another major end-use activity in Pakistan due to hot and long summer period. In the base year, this activity has been estimated to account for 500 kW·h and 350 kW·h per year per electrified household respectively in urban and rural areas. An increase of 1.0–2.8% p.a. has been assumed in specific electricity consumption for this end-use activity. At the same time, a reduction of about 10% in urban and rural areas has been assumed over the entire planning period on account of efficiency improvement in fans and coolers.

Air conditioning is a fast growing end-use activity in the Household sector. For the base year, the number of electrified households using air conditioners and specific electricity consumption for air conditioning have been estimated from the HESS survey. During the 8th Five Year Plan period a target of 163,000 per year for the local production of air conditioners has been envisaged. Keeping in view this target and the historical trend of use of air conditioners, the future growth in number of households using air conditioners has been assumed as 10% p.a. In addition, the specific electricity consumption on account of air conditioning has been assumed to increase at 5.7% p.a. during 1992/93–98, declining gradually to 3% p.a. and 1.5% p.a. respectively by 2008 and 2023. This increase in specific electricity consumption for air conditioning has been assumed to reflect the expected increase in average number of air conditioners per household which is expected with increase in income per household.

As for other appliances, the base year specific electricity consumption for this end-use category has been estimated from HESS survey. The income effect on electricity consumption for this category has been observed to be very pronounced, as shown in Figure B.1. As such, it has been assumed that the electricity consumption per household for other appliances will increase in future at a growth rate equal to that for GDP per household. However, a 15% reduction in specific electricity consumption for this category has also been assumed over the entire planning horizon to reflect efficiency improvement in the end-use devices. Table B.4 lists the specific electricity consumption for each end-use category assumed for different years.

As the MAED model allows consideration of only two end-use categories for electricity consumption in households, viz. air conditioning and other appliances, the above mentioned parameters estimated for both urban and rural households have been transformed to correspond to the input parameters of the MAED model.

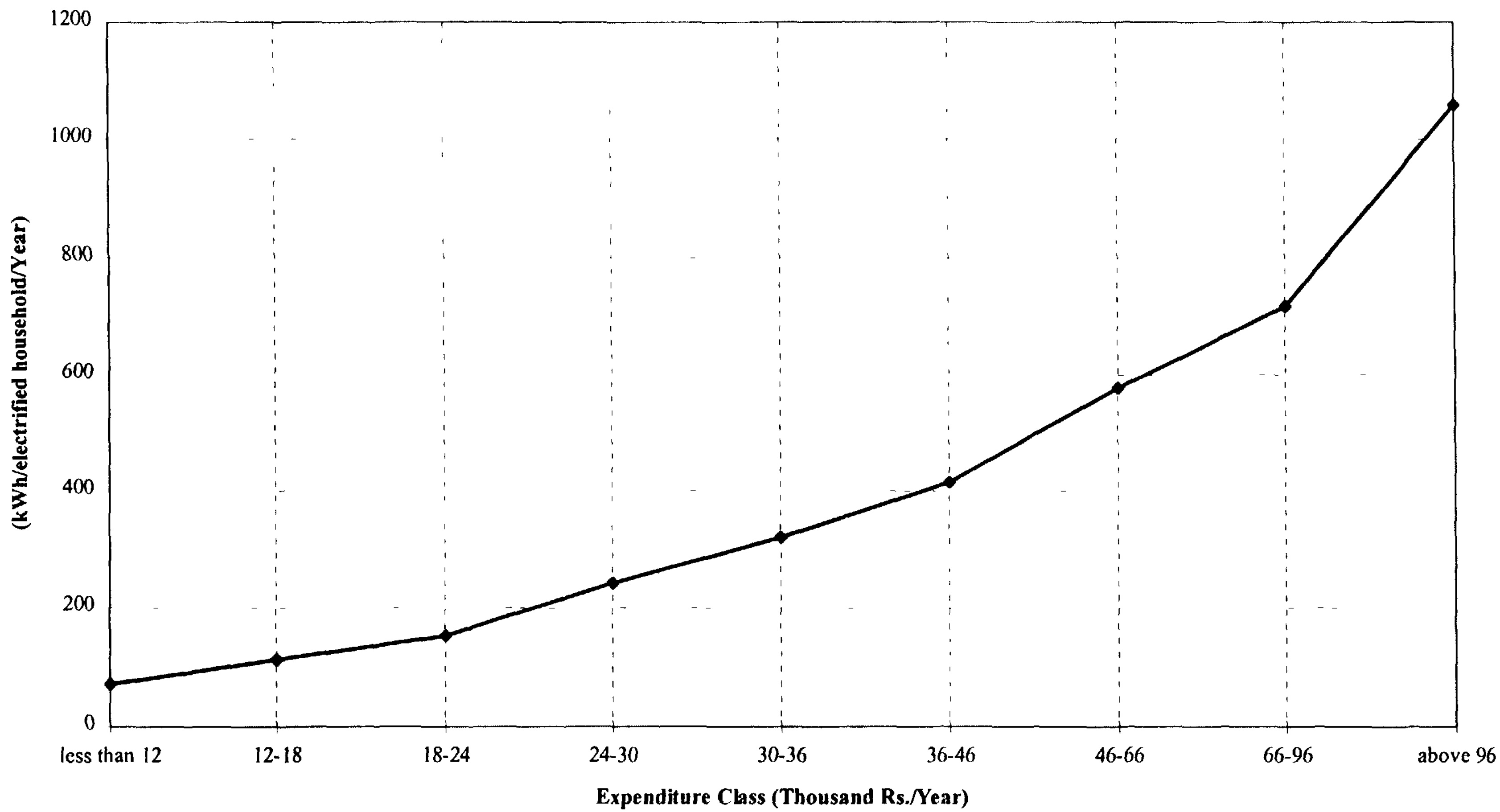

Fig. B.1 Average Electricity Consumption for Electric Appliances

For non-electric energy consumption in households, the end-use categories considered are cooking, water heating and space heating. Since the information available for the base year does not allow such dis-aggregation for the rural households and the water/space heating activities in these households are not common in the formal sense, all non-electric energy consumption of the rural households has been considered in a single end-use category, i.e. cooking. The specific energy consumption for this lumped category, in useful energy terms, has been estimated as 0.179 TOE per rural household in the base year. For future, this parameter has been assumed to increase at an average rate of about 0.5% p.a. for rural households. In the case of urban households, the specific energy consumption for cooking (0.231 TOE) has been kept constant in all the periods, assuming that while the cooking requirements per household will increase with increase in income, this increase will be off-set by changing social behavior involving use of pre-cooked/semi-cooked food. These urban and rural estimates for cooking have been aggregated to correspond to the value of MAED parameter COOKDW for the combined urban and rural population.

As for water heating, it has been assumed that all urban households use this facility. As such, the fraction of households using water heating has been taken as the urban fraction of total number of households. The specific energy consumption for water heating has been increased in proportion to increase in GDP/Capita.

The MAED parameters related to space heating activity include specification of type of old and new dwellings. The present stock of dwellings as well as the new dwellings have been assumed to be of single family units type. Although, there is now a trend of multistory housing units in some of the large cities, there is hardly any use of central heating systems and such systems are not likely to be used to any significant extent in the foreseeable future. As such, even these apartments can be treated as single family units for the purpose of estimating space heating requirements. Mostly natural gas is used for space heating. It has been estimated that only about 2% of the existing households used space heating in the base year. This share has been assumed to increase in future in line with the expected increase in gas connections. For new housing units, it has been assumed that initially 10% will be using space heating and this share will increase to 40% by the end of the planning horizon. The specific energy requirement for space heating, in useful energy terms, has been estimated as 1866 thousand kcal per year per household for the base year. This has been assumed to remain constant for pre-1992–93 buildings even for future years. As such, the value of ISO has been taken as zero throughout.

The end-use efficiencies of fossil fuels for cooking, water heating and space heating for the base year have been worked out from HESS estimates for individual fossil fuels and have been projected to improve by a factor of 1.1 by the terminal year. However, the end-use efficiency of non-commercial (traditional) fuels has been assumed to increase from the base year value of 13% to 16% by the end of planning horizon, in view of the efforts being made by Pakistan Council for Appropriate Technology and other agencies like GTZ of Germany for introduction of improved cook stoves. The use of these fuels has been assumed to slightly increase with time in line with the estimates of Planning Commission.

As for penetration of electricity for different thermal uses in households, the fact is that, natural gas, if available is the most preferred fuel. Further, the government is planning to provide natural gas to even small towns. As such, the use of electricity for cooking and water heating will remain limited. The use of electricity for water heating has been projected to be minimal, while that for cooking has been kept zero. However, it has been assumed that the share of electricity in space heating activity will increase gradually from the base year value of 5% to about 10% by 2022–23. Penetration of solar for thermal use has been envisaged nominally only for the water heating activity.

Table B.4. Specific Electricity Consumption in Households by End-use (Reference scenario)

(kW·h/electrified dwelling/year)

	1992–93	1997–98	2002–03	2007–08	2012–13	2017–18	2022–23
Lighting							
Urban	468	507	545	583	620	654	665
Rural	448	485	522	559	593	626	636
Total	457	495	532	568	604	638	649
Cooling							
Urban	499	539	580	621	659	695	706
Rural	349	377	403	428	448	463	459
Total	419	449	478	506	532	558	640
Other Appliances							
Urban	652	768	912	1101	1343	1581	1978
Rural	279	329	390	472	574	676	845
Total	452	449	610	723	880	10949	1327
Air conditioners							
Urban	2559	3114	3698	4287	4851	5356	5769
Rural	2559	3114	3698	4287	4851	5356	5769
Total	2559	3114	3698	4287	4851	5356	5769

B.1.8. Service Sector

For the Service sector, energy and electricity consumption are projected on the basis of floor area in the Service sector. It has been assumed that the floor area per employee in this sector will increase from the base year value of 10 sq.m/employee to 14.5 sq.m/employee by the year 2022–23. The share of labour force employed in Service sector has been correlated to the share of value added by this sector. Although, in the Reference scenario, the share of Service sector in total GDP has been projected to decline with time, the number of employees in this sector increases from 10.5 million to 23.5 million in 2022–23 due to increase in total labour force employed. As such, the total floor area in the Service sector increases from about 104.9 million sq.m to 340.1 million sq.m.

For the base year, it has been estimated that only 5% of the total area has air conditioning and about 50% has heating facilities. These fractions have been projected to increase with time to 26.9% and 65% by the terminal year. The heating activity, in fact, includes other thermal uses in this sector like hot water and cooking in restaurants, etc. The specific energy consumption for this activity has been estimated as 64 kcal/sq.m for the pre-1992–93 buildings and assumed as 65 kcal/sq.m for the new buildings. The specific electricity consumption for air conditioning has been estimated as 176 kW·h/sq.m/yr. These parameters have been kept constant for future years. The electricity consumption for other appliances in the pre-1992–93 floor area of the Service sector has been estimated as 33 kW·h/sq.m/yr. The electricity consumption for lighting is the major component of this activity in the Service sector. The average efficiency of lighting equipment will increase with time resulting in relatively lower specific electricity consumption. However, in view of expected increased use of office equipment and other electrical appliances in future, the specific electricity consumption for other appliances has been assumed to increase slightly from 33 kW·h/sq.m/a to 39 kW·h/sq.m/a in the old buildings and from 41 kW·h/sq.m/a to 45 kW·h/sq.m/a in the new buildings.

B.2. Projections of MAED Parameters in Optimistic and Constrained Scenarios

This section describes the hypotheses made for the construction of alternative scenarios with emphasis on those parameters for which the assumed values are different from the Reference scenario.

B.2.1. Demographic Parameters

Although the total population projections are common to all scenarios, the levels of urbanization and labour force employment have been assumed to be linked with economic development. As such different values have been assumed for these parameters in the Optimistic and Constrained scenarios.

The trend of people to move from rural to the urban areas is motivated by many factors, the key factor being that the urban areas are perceived to have more economic opportunities compared to the rural areas. Based on this assumption the share of urban population in the year 2022–23 has been taken as 44% in the Optimistic scenario and 40% in the Constrained scenario as compared to a value of 41.4% in the Reference scenario. The values for the years 2003 through the year 2018 have been estimated by following the same trend as that envisaged for the Reference scenario. The share of rural population (PRUR) has been determined by subtracting the share of urban population from unity.

To find out the share of population living in large cities for the Optimistic scenario and Constrained scenario the share of urban population and share of population in large cities in the Reference scenario have been extrapolated beyond 2022–23. Then the share of population in large cities for a given share of urban population, in both Optimistic scenario and Constrained scenario, have been taken the same as the share of population in large cities corresponding to the same share of population in the Reference scenario.

The fraction of potential labour force actually working has been assumed to be 47% in the Optimistic scenario and 44% in the Constrained scenario as compared to 45.5% in the Reference scenario for the terminal year 2022–23. The values for the period 2003 to 2022–23 have been determined by assuming the same trend as that envisaged for the Reference scenario values.

B.2.2. Agriculture Sector

Among the three economic growth scenarios considered in this study, there is very little difference between Reference scenario and Constrained scenario with respect to the value added of the Agriculture sector i.e. value added of Agriculture sector in Constrained scenario is only 2.8% lower than that in the Reference scenario in the year 2022–23. However, the Agriculture sector's value added in the same year in Optimistic scenario is 29.7% higher than the Reference scenario. For the Optimistic and Constrained scenarios, it is assumed that the motor fuel and electricity intensities will remain the same as in the Reference scenario.

B.2.3. Construction and Mining Sectors

For the Optimistic and Constrained scenarios it is assumed that the motor fuel and electricity intensities will remain the same as in the case of Reference scenario.

B.2.4. Manufacturing Sector

In the Optimistic scenario structure of the Manufacturing sector has been assumed to change gradually, after 1998, in such a manner that by the year 2022–23 the shares of Basic material industries and Machinery and equipment industries in value added of Manufacturing sector are higher by about 3% and 2% respectively while the shares of Consumer goods industries and Small scale industries in value added of Manufacturing sector are lower by about 3% and 2%, respectively, than in the Reference scenario. In line with the similar assumptions it is expected that in the Constrained scenario the shares of Basic material industries and Machinery & equipment will be lower by 2.6% and 3.4% respectively while the shares of Consumer goods and Small scale industries will be higher by 2.1% and 3.8% respectively. The structure of the Manufacturing industries in the three scenarios is shown in Tables 3.6 and 3.7.

In the Manufacturing sector, it is assumed that all other parameters remain the same in all the three scenarios.

B.2.4.1. Feedstocks

Fertilizer feedstocks which are calculated outside the MAED model will change among scenarios and these changes have been made in-line with the value added growth of Agriculture sector for these scenarios. Fertilizer feedstocks requirements, in the year 2022–23, will be 5.7 million TOE and 4.2 million TOE for Optimistic and Constrained scenarios, respectively.

B.2.5. Transport Sector

Intercity passenger transport activity level determining parameter DI (average annual intercity travel distance per person), urban average daily travel distance parameter (DU) and the number of persons per effective car (CO) have been projected keeping in view the GDP/capita and projections made for the Reference scenario.

The average annual distance driven per car in intercity travel (DIC) has been assumed as 4,200 km in Optimistic scenario and 3,800 km in Constrained scenario compared to the Reference scenario value of 4,011 km in 2022–23. The intermediate year values have been interpolated.

B.2.6. Households/ Services

The values of MAED parameters related to Households and Services sector for the Optimistic scenario and Constrained scenario are given in Table B.6, respectively. The changes in the values of these parameters in the Optimistic scenario and the Constrained scenario as compared to the Reference scenario are discussed below. The rationale for this change, where not mentioned explicitly, is based on judgment.

As mentioned earlier the specific energy consumption for cooking has been estimated separately for the urban (COOKDU) and rural (COOKDR) households and then these values have been aggregated to estimate the value of MAED parameter COOKDW. The value of

COOKDU has been kept constant for all the three scenarios while the value of COOKDR has been assumed to grow at a higher rate in the Optimistic scenario and at a lower rate in the Constrained scenario than that in the Reference scenario for the period 2013 to 2023. As a result of increase in COOKDR, COOKDW has been assumed as 2351 Mcal/dwelling/year in Optimistic scenario and 2270 Mcal/dwelling/year in Constrained scenario compared to the Reference scenario value of 2311 Mcal/dwelling/year in the year 2022–23.

The MAED parameter DWHW (the fraction of dwellings using hot water) has been assumed to be the same as the fraction of urban households and thus its value is 0.44 in Optimistic scenario, 0.40 in Constrained scenario as compared to 0.41 in the Reference scenario by the year 2022–23.

For the projections of the specific energy consumption for water heating in the households the growth rate of GDP/capita has been used in all the three scenarios viz. the Optimistic scenario, Constrained scenario and Reference scenario.

In the Reference scenario it was assumed that all the households will be electrified by the year 2013. For the Optimistic scenario and Constrained scenario the 100% electrification has been assumed by the years 2008 and 2018, respectively.

Separate estimates for the urban and rural households have been made for the fraction of electrified households using air conditioners and then the two have been aggregated to get the MAED parameter DWAC. For the urban households DWAC value for the terminal year of the study has been taken as 24.5% for the Optimistic scenario and 7.2% for the Constrained scenario as compared to 14.3% for the Reference scenario, while for the rural households this fraction is assumed as 7.75% for the Optimistic scenario and 3.0% for the Constrained scenario as compared to 4.3% in the Reference scenario. The values for the period 2003 to 2022–23 have been growing in line with the Reference scenario.

The growth rate of GDP per household has been applied to project the values of ELAPDW (the specific electricity consumption for other appliances) for the Optimistic scenario and Constrained scenario, as in the case of Reference scenario.

The fraction of old households using space heating (PREDW(3)) has been linked to the number of houses having gas connections and it has been assumed to be 40% in the Optimistic scenario and 20% in the Constrained scenario as compared to 30% in the Reference scenario. For new buildings (NEWDW(3)) this share has been taken as 70% in the Optimistic scenario and 50% in the Constrained scenario as compared to 60% in the Reference scenario.

The average floor area per employee in the Service sector (AREAL) has been assumed to grow at a slightly faster rate in Optimistic scenario due to higher economic growth and at a slightly lower rate in the Constrained scenario due to lower economic growth as compared to the Reference scenario. The values of AREAL in the terminal year are 16, 13, and 14.5 square meters per employee for Optimistic scenario, Constrained scenario and Reference scenario, respectively.

The share of Service sector floor area actually heated (AREAH) in the year 2022–23 has been taken as 70%, 60% and 65% in the Optimistic scenario, Constrained scenario and Reference scenario with smooth growth in the period 2003 to 2022–23.

Due to increased use of office equipment and other electrical appliances envisaged with higher economic growth and vice versa, the specific electricity consumption ($kW\cdot h/m^2/yr$) for other appliances (ELARO & ELARN) has been increased in the Optimistic scenario and decreased in the Constrained scenario as compared to the Reference scenario both for the old and new buildings.

The growth rates applied to the share of the air-conditioned Service sector floor area (AREAAC) for the period 2003 to 2022–23 are 12% in Optimistic scenario and 8% in the Constrained scenario as compared to 10% in the Reference scenario, in view of the different economic growth rates in the three scenarios.

B.3. Projection of MAED Parameters in the Energy Efficiency Scenario

Despite very low level of energy and electricity consumption in Pakistan, the efficiency of use is very low compared to that in developed countries. This is because of a number of reasons, e.g. poor efficiency of end-use appliances, distorted energy prices, lack of awareness among general public, etc. It is believed that the government policies can considerably influence energy conservation and efficiency improvement at the end-use level. The National Energy Conservation Centre (ENERCON), established in 1984, has carried out a number of studies to identify the potential of energy and electricity conservation in the various sectors. It has been estimated [63] that 5–40% energy savings are possible in different sectors through energy conservation and efficiency improvement measures. In view of this, an Energy Efficiency scenario for energy demand projections has been developed which assumes a vigorous effort by the government through regulations, pricing and awareness campaigns, aiming at realization of the identified energy/electricity saving potential in all sectors of the economy. The main features of this scenario are described below:

B.3.1. Agriculture Sector

ENERCON has estimated that both diesel and electric pumps in Pakistan are being used at very low efficiencies (e.g. 5.4% overall efficiency in case of diesel pumps and 21.5% in case of electric pumps, during the year 1985) due to badly maintained engines, slipping belts, running pumps below rated capacities, and incorrect motor speeds. The ENERCON envisaged efficiency targets for diesel and electric pumps of 14% and 35%, respectively [37]. Efficiency targets of 14% and 43% for diesel and electric pumps have been assumed for Energy Efficiency scenario of this study, by the year 2022–23.

Field surveys and operational retrofits have indicated 18% fuel savings potential in tractor operations for the agricultural uses [108]. Keeping in view these data, hourly fuel consumption of a tractor has been assumed to decline by 18% in Energy Efficiency scenario from Reference scenario for the year 2022–23. On the basis of these assumptions the intensities of motor fuels and electricity consumption per unit of Agriculture value added decline to 42.9% and 33.9%, respectively, of the base year value, by the year 2022–23 in Energy Efficiency scenario while the corresponding values in the Reference scenario are 52.5% and 41.6%.

B.3.2. Mining & Construction Sectors

Being smaller sectors of the economy and consuming small quantities of energy, for these sectors energy intensities have been assumed to be same in Energy Efficiency scenario as in Reference scenario.

B.3.3. Manufacturing Sector

The electricity, thermal and motor fuel energy intensities of Manufacturing sector are expected to change with time due to factors, such as: (i) change in the mix of basic materials, machinery and equipment, consumer goods and miscellaneous industries, (ii) improvements in current technologies and introduction of new technologies and processes, (iii) change in operation and maintenance practices of manufacturing industries reflecting their emphasis on energy conservation, (iv) increase in automation and (v) inter-fuel substitution etc. The energy intensity change over time due to structural changes in the Manufacturing sector is accounted for by the MAED model by considering sub-sector value added shares. However the cumulative effect of other factors, such as ii-v mentioned above, has to be reflected in the form of changes in energy intensity parameters.

Estimates of shares of various electricity end-uses in the Manufacturing sectors are; Motors: 80%, lighting: 4% and other uses (thermal processes, electrolysis, air conditioners, refrigerators, appliances): 16%, for the year 1985–86 [36]. Same end-use shares have been assumed for the year 1992–93. Further, the other uses category has been estimated to be subdivided into thermal processes and electrolysis: 50%, air conditioning and refrigeration: 40% and appliances: 10%, in the light of: (i) estimates of electricity use in steel mills (except Pakistan Steel Mills), (ii) information that only few industries are using electrolytic processes (e.g. caustic soda manufacturing industries) and no large scale aluminum or copper industries are present, and (iii) share of appliances in industrialized countries is only about 2% of the total electricity consumption of Manufacturing sector [109]. The potential energy savings, envisaged over the next 30 years, for each end-use category if vigorous energy conservation and efficiency improvement policies are adopted in Pakistan, are listed in Table B.5. It is assumed that the electricity intensity in 2022–23 will be lower by 15% in the Energy Efficiency scenario as compared to the Reference scenario. The intermediate year values have been estimated by gradually reducing the electricity intensities assumed in the Reference scenario (see Figure B.2).

Table B.5. Potential Electricity Savings in Manufacturing Sector

	Share of end-use	Potential savings
Electric Motors (Through energy efficient electric motors, – Adjustable speed drive, – Additional transformer capacity, – Replacement of sub-standard fans in industry)	80%	13%
Lighting	4%	30%
Others*	16%	22%
Total	100%	15%

* Thermal processes, electrolysis, appliances, air conditioners, refrigerators.

Source: Based on [56, 110]

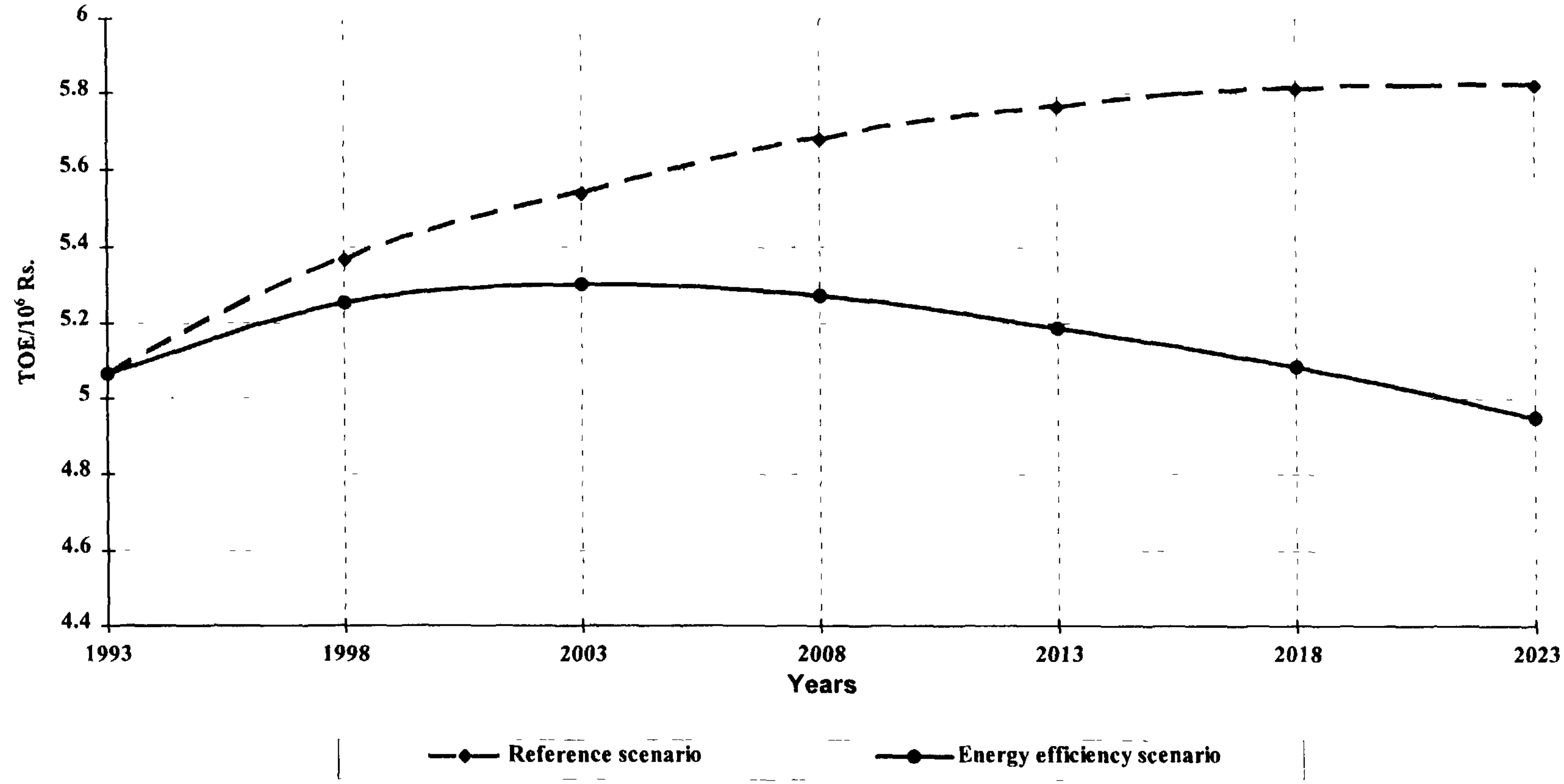

Fig. B.2 Electricity Intensity of Manufacturing Sector

Thermal energy intensities have been projected to decline by 40% (as compared to 25% decline in Reference scenario) over the next 30 years due to increased efficiency improvement, and energy conservation measures. A reduction of 10% has been assumed in the motor fuel energy intensity over the planning horizon. In the industrialized countries average boiler/furnace efficiency efficiency is over 85% as compared to about 70% in Pakistan [29]. An efficiency of 65% in the base year has been assumed in order to account for the low efficiencies of coal use in brick kilns (about 60% efficiency) and bagasse use in the sugar industry (about 40% efficiency). It is assumed that in the Energy Efficiency scenario thermal efficiencies will increase rapidly over the years to reach a level of 85% in 2022–23. The use of coke per ton of pig iron produced has been projected to decline from about 900 kg in the base year to 500 kg, in 2022–23, in the light of average consumption in the industrialized countries [107].

As already mentioned the set of parameters ICOGEN, EFFCOG and HELRATE represent the onsite self-generation and co-generation of electricity collectively. It is assumed that, as in the Reference Scenario, shares of co-generated and self-generated electricity in the Energy Efficiency scenario will reach a level of 66% and 34%, respectively, by the year 2022–23. In the Energy Efficiency scenario the efficiency of co-generation and self-generation are projected to increase to a level of 80% and 36% respectively compared to 74% and 33% respectively in the Reference scenario. ICOGEN is assumed to increase to 0.33 in Energy Efficiency scenario as compared to 0.25 in Reference scenario.

B.3.4. Transport Sector

Modal shares have been changed in Energy Efficiency scenario as compared to Reference scenario for both freight and passenger transportation. These changes are assumed from second period as the modal shares for the first period reflect the Eighth Five Year Plan targets.

The share of trains, particularly of electric trains, which is more efficient mode of freight and inter-city passenger transportation is assumed to increase in Energy Efficiency scenario. In urban passenger transportation the share of mass transit systems also is supposed to increase. This assumption implies that recent plans for building rail based mass transit projects, of the National Mass Transit Authority in four major cities of the country (Karachi, Lahore, Islamabad/Rawalpindi and Faisalabad) will be implemented in due course of time.

Specific fuel consumption of vehicles, used for freight and passenger transportation, is assumed to change due to: (i) induction of new vehicles, (ii) change in the mix of fleet, (iii) better operation and maintenance practices e.g. tuning, alignment, speed, load etc. and (iv) improvements in traffic flows and quality of roads.

In the base year 4% of truck population is assumed (assumption is based on [56]) to be of trucks with trailers having average loading capacity of 16 tons. For the Energy Efficiency scenario it is assumed that half of the truck population will be in the form of trailers in the year 2022–23. By this assumption an average truck (average of mix of trailers and conventional trucks) will consume 370 kcal/ton-km in the year 2022–23 in the Energy Efficiency scenario (Table 4.20) compared to 470 kcal/ton-km in the Reference scenario for inter-city freight transportation. For a comparison, it may be noted that in early 1980's, an average truck was consuming 239 kcal/ton-km in OECD countries and 309 kcal/ton-km in USA [111]. Fuel consumption per ton of urban freight transport has been assumed to be some 5% lower in Energy Efficiency scenarios by the year 2022–23, compared to the Reference scenario.

In the Pakistani railways system, fuel uses for a ton-km and for a passenger-km is almost as good as in USA and Japan due to high numbers of passengers per train and high load factors of freight trains. During the year 1982, specific fuel consumption in USA railways were 97.4 kcal/ton-km for freight trains and 112.2-kcal/passenger-km for passenger trains [111] and the respective data for Japanese railways were 112 kcal/ton-km and 101 kcal/passenger-km during the year 1990 [112]. For the Reference scenario of this study these values are assumed 81 kcal/ton-km and 72.6 kcal/passenger-km, for the year 2022–23, which reflect 10% overall technological improvements from the base year 1992–93. The specific energy consumption of freight and passenger trains for the Energy Efficiency scenario have been assumed to be 5% lower than the Reference scenario, by the year 2022–23.

In a recent study [27], carried out by International Energy Agency (IEA), 1% per annum efficiency improvement was assumed in their reference scenario and 2% per annum improvement was assumed in their efficiency scenario for the air transport during the period 1991–2000 for Europe, Japan and USA. As Pakistan imports its aircraft from USA and Europe, so for efficiency scenario 1.5% per annum efficiency improvement has been assumed for planes during the period 1993–2023.

In the light of 0.5%–1.5% p.a. efficiency improvement envisaged for OECD's passenger cars for the period 1991–2010 [27]. 10% overall efficiency improvement in passenger cars, during the period 1993–2023, in Reference scenario, corresponding to 0.32% p.a. improvement has been assumed for Pakistan. For the Energy Efficiency scenario about 1.0% per annum efficiency improvement has been considered for the whole planning horizon.

United Nations Economic Commission for Europe considered 16–18% efficiency improvement, in passenger transport by bus for USA and Europe during the period 1975–2000 [107]. Keeping in view these considerations along with local road and traffic conditions 25% efficiency improvement have been assumed in Energy Efficiency scenario for the passenger buses over the next three decades.

B.3.5. Household and Service Sectors

Electricity consumption in Households could be reduced substantially by conservation and efficiency improvement measures. This potential, however, can only be realized gradually. For the Energy Efficiency scenario of this study, assessment of electricity saving in major end-use categories has been carried out and appropriate levels of electricity saving have been assumed during the next 30 years period. The following paragraphs summarize main assumptions of this analysis.

Lighting activity is responsible for about one-third of present electricity consumption in the households. Due to large price differential in the installation costs of incandescent bulbs and fluorescent tubes, most of the urban and rural households use incandescent bulbs inspite of their higher electricity consumption for the same level of lighting service. According to a recent survey [15], there are on the average 3.85 bulbs and 1.60 tubes per urban household and 4.22 bulbs and 0.47 tubes per rural household. It has been assumed that the share of fluorescent tubes in the total stock of lighting devices in the household sector will increase from about 20% now to 46% by the year 2022–23, resulting in about 29% less consumption for lighting compared to that in the Reference scenario in the terminal year.

Fans and air coolers also account for about 30% of present electricity consumption in Households. The efficiency of locally manufactured fans vary widely due to variation in quality of materials used. Most of the fans manufactured in the country consume 15–40% more electricity compared to good quality fans of equivalent size [113]. Although, there are national standards for the quality of electric equipment produced locally, enforcement of such standards is practically non-existent. In this scenario it has been assumed that the national standards will be gradually enforced and better quality fans will be manufactured in the country. Further, such fans will gradually replace the poor quality fans and the average efficiency of the stock will improve with time. It is, therefore, assumed that the average electricity consumption per household for air-cooling will be 17% lower than that in the Reference scenario in the terminal year.

Air conditioning is a fast growing activity in households. At present, only 1% of electrified households are using air conditioning. However, it is expected that with increase in income levels this facility will be used by a large number of households. The electricity consumption of imported as well as locally assembled air conditioners of the same size vary from 2250–3250 watt-hr./hr. It has been estimated [114] that about 15% of electricity consumption for air conditioning in household can be saved by improving insulation of the cooled area and appropriate adjustment of thermostats. It is assumed that about 2/3 rd of the potential (10%) will be realized by the year 2022–23 in the Energy Efficiency scenario. Further, the coefficient of performance of air conditioners (EFFAC) has been assumed to improve to 2.3 in the Energy Efficiency scenario compared to a value of 2.2 in the Reference scenario, in the year 2022–23.

Other electric appliances used in households include refrigerators, irons, televisions, water pumps, washing machines etc. Among these, refrigerators, washing machines and water pumps account for more than 50% of electricity consumed for this category. The efficiency of commercially available refrigerators vary to a large extent. The no-frost type refrigerators consume about 20% less electricity compared to older technology. In the case of washing machines and water pumps, the motors used in these devices are generally of poor quality, and repeated rewinding of these motors is a common phenomenon. As such, the efficiency of these devices is very low compared to the standard ones. It has been assumed that on the average about 20% saving in electricity consumption of other electric appliances compared to the Reference scenario will be achieved by the year 2022–23.

As for other end-use activities in the households, viz. cooking, water heating and space heating, it has been assumed that in the rural areas about 20% savings in energy consumption for thermal uses, mainly cooking, will gradually be achieved by the year 2022–23 through use of improved cook stoves. As a result the energy consumption for thermal uses in rural households will be 1775 Mcal/household as compared to 2219 Mcal/household in the Reference scenario. For the urban households the energy consumption per household for thermal uses has been assumed to remain the same as in the Reference scenario. Further it has been assumed that the efficiency of fossil fuels combustion in cooking, water heating and space heating devices will increase from present levels of about 60% to 70%, by the year 2022–23.

In the service sector, lighting activity accounts for about 65% of the present electricity consumption in this sector. The use of fluorescent tubes/bulbs is very common, with a share of 80% in total lighting devices. Still, there is considerable potential of electricity saving in this sector from lighting activity. It has been estimated that about 27% of electricity can be saved by replacing incandescent bulbs with fluorescent tubes/bulbs and other high efficiency lighting devices [37]. Keeping in view that the end-users in this sector can afford the high cost of fluorescent tubes and other high efficiency lamps, it has been assumed that most of the above estimated saving potential can be realized. A modest improvement in the efficiency of office equipment and other equipment is also assumed. The overall efficiency improvement in electricity consumption in the Service sector, excluding air conditioning, has thus been assumed as 20% by the year 2022–23.

Air conditioning is another major end-use activity in the Service sector, which at present accounts for 20% of the electricity consumption in the sector. Both central air conditioning systems and room air conditioners are used in this sector. The energy efficiency ratio (EER) of 1.5 ton capacity room air conditioners used in the country vary form 6.7 to 9.3, while the same sized units available in the industrialized countries have EER of up to 12. Use of such high efficiency air conditioners can reduce electricity consumption for this activity by about one-third. The central air conditioning units have EER of 12–15, depending upon their size and quality. But some small units with EER as low as 5.5 are also marketed in the country. According to a study by ENERCON, [37] about 30% of the cooling load in the Service sector can be reduced through better insulation of the cooled areas, adjustment of thermostat control and use of better quality air conditioning units. In this scenario, it has been assumed that this potential could gradually be realized by the year 2022–23.

For thermal uses of energy in the Service sector the efficiency of energy use can be increased by better insulation and other conservation measures. In this case, it has been assumed that energy consumption per sq.m will gradually decrease from 65 kcal/sq.m used in the reference case to 55 kcal/sq.m.

Based on above assumptions, the input parameters of MAED for household and Service sector for the Energy Efficiency scenario have been calculated and are given in Table B.6.

Table B.6 MAED Parameters

A. Description of Constant Parameters (Base Year)

Description	Variable	Value
INDUSTRY		
1 Specific energy consumption per monetary unit of value added by sector and energy form	EI(I,J)	
Agriculture		
- Motor fuel (final, Mcal/Rs of value added)	EI AGR MF	0 06207
- Electricity (final, kW h/Rs of value added)	EI AGR EL	0 01893
- Thermal uses (final, Mcal/Rs of value added)	EI AGR TH	0 0
Construction		
- Motor fuel (final, Mcal/Rs of value added)	EI CON MF	0 01909
- Electricity (final, kW h/Rs of value added)	EI CON EL	0 0000950
- Thermal uses (final, Mcal/Rs of value added)	EI CON TH	0 0
Mining		
- Motor fuel (final, Mcal/Rs of value added)	EI MIN MF	0 07668
- Electricity (final, kW h/Rs of value added)	EI MIN EL	0 00261
- Thermal uses (final, Mcal/Rs of value added)	EI MIN TH	0 0
Manufacturing		
* Basic Material		
- Motor fuel (final, Mcal/Rs of value added)	EI BM MF	0 00791
- Electricity (final, kW·h/Rs of value added)	EI BM EL	0 13591
- Thermal uses (final, Mcal/Rs of value added)	EI BM US	0 71293
* Machinery and Equipment		
- Motor fuel (final, Mcal/Rs of value added)	EI ME MF	0 0024
- Electricity (final, kW·h/Rs of value added)	EI ME EL	0 04060
- Thermal uses (final, Mcal/Rs of value added)	EI ME US	0 07597
* Non-durable Goods		
- Motor fuel (final, Mcal/Rs of value added)	EI ND MF	0 00240
- Electricity (final, kW·h/Rs of value added)	EI ND EL	0 07032
- Thermal uses (final, Mcal/Rs of value added)	EI ND US	0 28882
* Miscellaneous industries		
- Motor fuel (final, Mcal/Rs of value added)	EI MI MF	0 00239
- Electricity (final, kW h/Rs of value added)	EI MI EL	0 02966
- Thermal uses (final, Mcal/Rs of value added)	EI MI US	0 00467
2 Share of useful thermal energy demand of manufacturing by process category	PUSIND(I,J)	
* Basic Materials		
- Steam generation	PUSIND(1,1)	0 228
- Furnace/direct heat	PUSIND(1,2)	0 754
- Space/water heating	PUSIND(1.3)	0 018
* Machinery and Equipment		
- Steam generation	PUSIND(2.1)	0 335
- Furnace/direct heat	PUSIND(2.2)	0 422
- Space/water heating	PUSIND(2,3)	0 243

Table B.6 MAED Parameters

A. Description of Constant Parameters (Base Year) (cont.)

* Non-durable Goods		
- Steam generation	PUSIND(3.1)	0 855
- Furnace/direct heat	PUSIND(3.2)	0 075
- Space/water heating	PUSIND(3,3)	0 070
* Miscellaneous industries		
- Steam generation	PUSIND(4,1)	0 858
- Furnace/direct heat	PUSIND(4,2)	0 058
- Space/water heating	PUSIND(4.3)	0 084
3 Steel production Constants used to project the amount of steel produced		
- (million tons)	CPST(1)	0 33865
- (tons/1000 Rs of value added)	CPST(2)	0 01395
4 Feedstock requirements Constants used to project feedstock requirements of the petrochemical industry		
- (million TOE)	CFEED(1)*	0 0
- (TOE/Rs of value added)	CFEED(2)	0 0
TRANSPORTATION		
5 Constants used to project the total demand for freight transportation		
- (10^9 ton-km)	CTKFRT(1)	26 1697
- (ton-km/Rs of value added)	CTKFRT(2)	0 04805
6 Constants used to project the total motor fuel demand for international, military and miscellaneous transport		
- (Pcal)	CMISMF(1)	3 05460
- (Pcal/Rs)	CMISMF(2)	0 00089
HOUSEHOLD/SERVICE		
7 Degree-day	DD	300
8 Fraction of dwellings in areas where space heating is required	DWSH	1 0
9 Total stock of dwellings in the base year (million dwellings)	DW	16 806
10 Specific space heat requirements of "Old" dwellings by type		
(1) Single family house with central heating (Mcal/dw/yr)	SHDWO(1)	0 0
(2) Apartment with central heating (Mcal/dw/yr)	SHDWO(2)	0 0
(3) Dwelling with room heating only (Mcal/dw/yr)	SHDWO(3)	1866 5
11 Share of floor area heated in Service sector	ARSH	1 0
12 Total floor area of Service sector buildings in base year (million square meters)	TAREA	104 925
13 Constant used to project the Service sector share in the total labour force	CPLSER	1 6032
14 Specific heat requirements (useful energy) of "Old" Service sector buildings (Mcal/sqm/yr)	HAREAO	63 6
15 Amount of Non-commercial fuels used in the base year (million TCE)	BYRNCF	27 51839

* Feedstocks requirements have been computed outside the model

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value

Discription	Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
A Demography								
1 Total population (million)	PO	120 83	138 92	158 64	177 74	196 72	215 6	234 5
2 Fraction at population of age 15-64 (potential labour force)	PLF	0 6557	0 6644	0 6771	0 6948	0 7169	0 732	0 747
3 Fraction of potential labour force actually working R	PARTLF	0 4036	0 4099	0 4144	0 420 9	0 4273	0 440	0 455
O		0 4036	0 4099	0 4165	0 4250	0 4370	0 452	0 470
C		0 4036	0 4099	0 4130	0 4160	0 4220	0 430	0 440
E		0 4036	0 4099	0 4144	0 420 9	0 4273	0 440	0 455
4 Share of population living outside large cities R	POLC	0 805	0 785	0 766	0 747	0 727	0 70	0 69
O		0 805	0 785	0 758	0 730	0 705	0 67	0 65
C		0 805	0 785	0 770	0 758	0 741	0 72	0 71
E		0 805	0 785	0 766	0 747	0 727	0 70	0 69
5 Share of rural population (according to UN definition)R	PRUR	0 685	0 665	0 646	0 626	0 612	0 59	0 58
O		0 685	0 665	0 638	0 615	0 595	0 57	0 56
C		0 685	0 665	0 651	0 638	0 623	0 61	0 60
E		0 685	0 665	0 646	0 626	0 612	0 59	0 58
6 Average household size (persons/household) R	CAPH	7 1899	7 0897	6 9899	6 8909	6 7928	6 695	6 600
O		7 1899	7 0897	6 9881	6 8877	6 7883	6 689	6 592
C		7 1899	7 0897	6 9911	6 8932	6 7956	6 699	6 604
E		7 1899	7 0897	6 9899	6 8909	6 7928	6 695	6 600
B GDP-Formation and expenditure								
Total GDP (10^9 Rs) R	Y	1200 455	1682 313	2358 160	3307 144	4638 029	6505 47	9123 75
O		1200 455	1682 313	2472 220	3803 595	5849 276	9006 25	13855 23
C		1200 455	1682 313	2252 26	2944 034	3819 488	4935 15	6297 75
E		1200 455	1682 313	2358 160	3307 144	4638 029	6505 47	9123 75
Distribution of GDP formation by kind of economic activity among following sectors								
1 Agriculture R	PYAG	0 2481	0 2249	0 1999	0 1743	0 1519	0 132	0 115
O		0 2481	0 2249	0 1976	0 1679	0 1420	0 118	0 098
C		0 2481	0 2249	0 2073	0 1930	0 1810	0 170	0 162
E		0 2481	0 2249	0 1999	0 1743	0 1519	0 132	0 115
2 Construction R	PYB	0 0415	0 0431	0 0431	0 0431	0 0431	0 043	0 043
O		0 0415	0 0431	0 0425	0 0397	0 0370	0 034	0 032
C		0 0415	0 0431	0 0441	0 0441	0 0434	0 042	0 042
E		0 0415	0 0431	0 0431	0 0431	0 0431	0 043	0 043
3 Mining R	PYMIN	0 0062	0 0075	0 0087	0 0095	0 0104	0 011	0 012
O		0 0062	0 0075	0 0087	0 0091	0 0095	0 009	0 010
C		0 0062	0 0075	0 0087	0 0100	0 0113	0 012	0 014
E		0 0062	0 0075	0 0087	0 0095	0 0104	0 011	0 012
4 Manufacturing R	PYMAN	0 1729	0 1978	0 2211	0 2448	0 2686	0 292	0 314
O		0 1729	0 1978	0 2268	0 2657	0 3044	0 340	0 373
C		0 1729	0 1978	0 2121	0 2244	0 2348	0 243	0 249
E		0 1792	0 1978	0 2211	0 2448	0 2686	0 292	0 314
5 Energy R	PYEN	0 0323	0 0342	0 0367	0 0393	0 0422	0 045	0 048
O		0 0323	0 0342	0 0354	0 0354	0 0354	0 035	0 035
C		0 0323	0 0342	0 0367	0 0398	0 0430	0 046	0 051
E		0 0323	0 0342	0 0367	0 0393	0 0422	0 045	0 048
6 Services R	PYSER	0 4990	0 4925	0 4905	0 4889	0 4837	0 475	0 465
O		0 4990	0 4925	0 4890	0 4823	0 4716	0 460	0 450
C		0 4990	0 4925	0 4911	0 4887	0 4865	0 484	0 479
E		0 4990	0 4925	0 4905	0 4889	0 4837	0 475	0 465

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Discription		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
7 Distribution of manufacturing value added by sub-sector	R	PVAIG	0 244	0 2510	0 2681	0 280	0 2893	0 2976	0 3062
- Basic Materials	O		0 244	0 2510	0 2720	0 295	0 3147	0 3292	0 3366
	C		0 244	0 2510	0 2624	0 272	0 2778	0 2802	0 2804
	E		0 244	0 2510	0 2681	0 280	0 2893	0 2976	0 3062
- Mach & Equipment	R	PVAM	0 068	0 0893	0 1136	0 137	0 1616	0 1848	0 2064
	O		0 068	0 0893	0 1156	0 144	0 1746	0 2016	0 2263
	C		0 068	0 0893	0 1086	0 127	0 1432	0 1589	0 1727
	E		0 068	0 0893	0 1136	0 137	0 1616	0 1848	0 2064
- Non-durable Goods	R	PVAC	0 372	0 3661	0 3532	0 342	0 3307	0 3189	0 3070
	O		0 372	0 3661	0 3499	0 333	0 3128	0 2925	0 2757
	C		0 372	0 3661	0 3578	0 350	0 3441	0 3365	0 3281
	E		0 372	0 3661	0 3532	0 342	0 3307	0 3189	0 3070
- Miscellaneous ind	R	PVAMIS	0 314	0 2936	0 2651	0 239	0 2184	0 1987	0 1805
	O		0 314	0 2936	0 2625	0 226	0 1979	0 1768	0 1614
	C		0 314	0 2936	0 2712	0 250	0 2350	0 2244	0 2188
	E		0 314	0 2936	0 2651	0 239	0 2184	0 1987	0 1805
C Industry									
1 Ratio of energy intensity in current year reltive to the base year by sector (I) and energy form (J) Sectors									
1 AGR=Agricuture Energy from									
1 MF=Motor fuels	R	CH AGR.MF	1 00	0 917	0 844	0 76	0 685	0 601	0 525
	O		1 00	0 917	0 844	0 76	0 685	0 601	0 525
	C		1 00	0 917	0 844	0 76	0 685	0 601	0 525
	E		1 00	0 885	0 790	0 69	0 602	0 510	0 429
2 EL=Electricity	R	CH AGR EL	1 00	0 878	0 754	0 66	0 577	0 491	0 416
	O		1 00	0 878	0 754	0 66	0 577	0 491	0 416
	C		1 00	0 878	0 754	0 66	0 577	0 491	0 416
	E		1 00	0 841	0 710	0 59	0 496	0 411	0 339
3 TH=Thermal uses	R	CH AGR.TH	1 00	1 000	1 000	1 00	1 000	1 000	1 000
	O		1 00	1 000	1 000	1 00	1 000	1 000	1 000
	C		1 00	1 000	1 000	1 00	1 000	1 000	1 000
	E		1 00	1 000	1 000	1 00	1 000	1 000	1 000
2 CON=Construction Energy from									
1 MF=Motor fuels	R	CH CON MF	1 00	1 100	1 200	1 30	1 450	1 600	1 750
	O		1 00	1 100	1 200	1 30	1 450	1 600	1 750
	C		1 00	1 100	1 200	1 30	1 450	1 600	1 750
	E		1 00	1 095	1 188	1 27	1 407	1 536	1 663
2 EL=Electricity	R	CH CON EL	1 00	2 010	3 540	5 71	8 780	13 210	19 410
	O		1 00	2 010	3 540	5 71	8 780	13 210	19 410
	C		1 00	2 010	3 540	5 71	8 780	13 210	19 410
	E		1 00	1 990	3 469	5 48	8 253	12 153	17 469
3 TH=Thermal uses	R	CH CON TH	1 00	1 000	1 000	1 00	1 000	1 000	1 000
	O		1 00	1 000	1 000	1 00	1 000	1 000	1 000
	C		1 00	1 000	1 000	1 00	1 000	1 000	1 000
	E		1 00	1 000	1 000	1 00	1 000	1 000	1 000
3 Min=Mining Energy from									
1 MF=Motor fuels	R	CH MIN MF	1 00	1 250	1 500	1 75	2 000	2 250	2 500
	O		1 00	1 250	1 500	1 75	2 000	2 250	2 500
	C		1 00	1 250	1 500	1 75	2 000	2 250	2 500
	E		1 00	1 244	1 485	1 71	1 940	2 160	2 375

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
2 EL=Electricity	R	CH MIN EL	1 000	1 000	1 000	1 000	1 000	1 000	1 000
	O		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	C		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	E		1 000	0 990	0 980	0 960	0 940	0 920	0 900
3 TH=Thermal uses	R	CH MIN TH	1 000	1 000	1 000	1 000	1 000	1 000	1 000
	O		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	C		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	E		1 000	1 000	1 000	1 000	1 000	1 000	1 000
2 Ratio of energy intensity in current year relative to the base year in manufacturing by energy form									
1 MF=Motor fuels	R	CH MAN MF	1 000	1 000	1 000	1 000	1 000	1 000	1 000
	O		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	C		1 000	1 000	1 000	1 000	1 000	1 000	1 000
	E		1 000	0 980	0 960	0 940	0 920	0 910	0 900
2 EL=Electricity	R	CH MAN EL	1 000	1 060	1 093	1 121	1 138	1 148	1 150
	O		1 000	1 060	1 093	1 121	1 138	1 148	1 150
	C		1 000	1 060	1 093	1 121	1 138	1 148	1 150
	E		1 000	1 037	1 047	1 041	1 024	1 004	0 978
3 US=Thermal uses	R	CH MAN TH	1 000	0 928	0 870	0 823	0 787	0 764	0 750
	O		1 000	0 928	0 870	0 823	0 787	0 764	0 750
	C		1 000	0 928	0 870	0 823	0 787	0 764	0 750
	E		1 000	0 887	0 798	0 734	0 682	0 637	0 600
3 Share of useful thermal energy demand in manufacturing for steam and space and water heating		STSHI	0 0	0 0	0 0	0 0	0 0	0 0	0 0
4 Share of useful thermal energy demand in manufacturing for steam generation		STI	0 0	0 0	0 0	0 0	0 0	0 0	0 0
5 Share of low-temperature process heat in the total low and medium temperature process heat		LTH	0 2	0 2	0 2	0 2	0 2	0 2	0 2
6 Penetration of electricity on the various markets of useful thermal energy demand in manufacturing Categories		ELP I STM	0 000	0 000	0 000	0 000	0 000	0 000	0 000
1 Steam generation		ELP I FUR	0 000	0 002	0 010	0 030	0 060	0 080	0 100
2 Furnace/direct heat		ELP I SH	0 000	0 000	0 000	0 000	0 000	0 000	0 000
3 Space/water heating									
7 Average electricity penetration into thermal uses in manufacturing		ELP I AVE	0 000	0 000	0 000	0 000	0 000	0 000	0 000
8 Contributing of heat pumps to steam generation and space and water heating uses in manufacturing		HPI	0 000	0 000	0 000	0 000	0 000	0 000	0 000
9 Coefficient of performance of (electric) heat pumps in manufacturing		EFFHPI	2 0	2 0	2 0	2 0	2 0	2 0	2 0
10 District heat penetration for steam generation and space and water heating in manufacturing		IDH	0 0	0 0	0 0	0 0	0 0	0 0	0 0
11 Solar penetrating in low	R	SPLT	0 0	0 0000	0 001	0 0025	0 0050	0 01	0 02
temperature process heat	O		0 0	0 0000	0 001	0 0025	0 0050	0 01	0 02
and space/water heating	C		0 0	0 0000	0 001	0 0025	0 0050	0 01	0 02
in manufacturing	E		0 0	0 0005	0 002	0 0050	0 0100	0 02	0 03

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
12 Solar penetration in medium temperature process heat in manufacturing	R	SPHT	0 0	0 0	0 000	0 0010	0 0025	0 0050	0 010
	O		0 0	0 0	0 000	0 0010	0 0025	0 0050	0 010
	C		0 0	0 0	0 000	0 0010	0 0025	0 0050	0 010
	E		0 0	0 0	0 001	0 0025	0 0050	0 0100	0 015
13 Approximate share of useful thermal energy demand that can be met by a solar installation		FIDS	0 8	0 8	0 8	0 8	0 8	0 8	0 8
14 Share of the manufacturing demand for low temperature steam and space/water	R	ICOGEN	0 17654	0 190	0 205	0 220	0 230	0 240	0 250
heating which is supplied	O		0 17654	0 190	0 205	0 220	0 230	0 240	0 250
by fossil fuels but with	C		0 17654	0 190	0 205	0 220	0 230	0 240	0 250
cogeneration of electricity	E		0 17654	0 205	0 230	0 255	0 280	0 305	0 330
15 System efficiency of cogeneration	R	EFFCOG	0 2139	0 2601	0 2991	0 3356	0 3696	0 4013	0 4306
	O		0 2139	0 2601	0 2991	0 3356	0 3696	0 4013	0 4306
	C		0 2139	0 2601	0 2991	0 3356	0 3696	0 4013	0 4306
	E		0 2139	0 2584	0 3019	0 3445	0 3861	0 4268	0 4665
16 Ratio heat electricity in output of cogenration systems		HELRAT	0 85879	1 0457	1 2325	1 4194	1 6063	1 7931	1 9800
17 Average efficiency of fossil fuel use for thermal process j in manufacturing relative	R	EEF I STM	0 6478	0 661	0 674	0 686	0 699	0 712	0 725
to the efficiency of	O		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
electricity (same categories	C		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
as for ELPIND above)	E		0 6478	0 700	0 750	0 790	0 820	0 840	0 850
	R	EEF I FUR	0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	O		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	C		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	E		0 6478	0 700	0 750	0 790	0 820	0 840	0 850
	R	EFF I SH	0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	O		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	C		0 6478	0 661	0 674	0 686	0 699	0 712	0 725
	E		0 6478	0 700	0 750	0 790	0 820	0 840	0 850
18 Average efficiency of fossil fuel use in thermal process relative to the efficiency of electricity									
19 Share of steel produced in non-electric furnaces		EFF I AVE	0 0	0 0	0 0	0 0	0 0	0 0	0 0
20 Specific consumption of pig iron in non-electric steel		BOF	1 0	1 0	1 0	1 0	1 0	1 0	1 0
works		IRNOST	1 050	1 050	1 050	1 050	1 050	1 050	1 050
21 Coke input in blast furnaces per unit output of pig iron	R	EICOK	905	870	835	800	765	730	700
(kg/ton)	O		905	870	835	800	765	730	700
	C		905	870	835	800	765	730	700
	E		905	837	769	701	633	565	500

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
D Transportation									
1 Fraction of total freight transportation made by									
- truck	R	TRU	0 82192	0 7418	0 7130	0 6810	0 6490	0 6170	0 585
	O		0 82192	0 7418	0 7130	0 6810	0 6490	0 6170	0 585
	C		0 82192	0 7418	0 7130	0 6810	0 6490	0 6170	0 585
	E		0 82192	0 7418	0 6972	0 6517	0 6074	0 5645	0 520
- rail	R	FTRA	0 11733	0 1546	0 1870	0 2190	0 251	0 283	0 315
	O		0 11733	0 1546	0 1870	0 2190	0 251	0 283	0 315
	C		0 11733	0 1546	0 1870	0 2190	0 251	0 283	0 315
	E		0 11733	0 1546	0 2028	0 2483	0 2926	0 3355	0 380
- barge		BA	0 0	0 0	0 0	0 0	0 0	0 0	0 0
- pipelines		PIP	0 06075	0 1036	0 10	0 10	0 10	0 10	0 10
2 share of local truck transportation in the total truck transportation	R	TRUL	0 14536	0 145	0 1560	0 1630	0 1730	0 1820	0 1910
	O		0 14536	0 145	0 1560	0 1630	0 1730	0 1820	0 1910
	C		0 14536	0 145	0 1560	0 1630	0 1730	0 1820	0 1910
	E		0 14536	0 145	0 1721	0 1995	0 2223	0 2436	0 2692
3 Fraction of total freight traffic made by electric trains	R	TRAEF	0 0298	0 030	0 045	0 065	0 090	0 120	0 160
	O		0 0298	0 030	0 045	0 065	0 090	0 120	0 160
	C		0 0298	0 030	0 045	0 065	0 090	0 120	0 160
	E		0 0298	0 030	0 050	0 080	0 120	0 160	0 200
4 Share of steam trains in total freight transportation by rail		TRASTF	0 0005	0 0002	0 0001	0 0	0 0	0 0	0 0
5 Energy intensity of trucks (kcal/t-km)	R	DTRU	523 54	515 0	506 0	497 0	488 0	479 0	470 0
	O		523 54	515 0	506 0	497 0	488 0	479 0	470 0
	C		523 54	515 0	506 0	497 0	488 0	479 0	470 0
	E		523 54	488 0	456 0	428 0	404 0	348 0	370 0
6 Energy intensity of trucks for local transportation (kcal/t-km)	R	DTRUL	877 42	863 0	848 0	833 0	818 0	804 0	790 0
	O		877 42	863 0	848 0	833 0	818 0	804 0	790 0
	C		877 42	863 0	848 0	833 0	818 0	804 0	790 0
	E		877 42	858 7	839 5	816 3	793 5	771 8	750 5
7 Energy intensity of diesel freight trains (kcal/t-km)	R	DTRAF	90 0	88 5	87 0	85 5	84 0	82 5	81 0
	O		90 0	88 5	87 0	85 5	84 0	82 5	81 0
	C		90 0	88 5	87 0	85 5	84 0	82 5	81 0
	E		90 0	88 1	86 1	83 8	81 5	79 2	77 0
8 Average ratio between energy intensity of steam trains and diesel trains		STDTRA	8 9046	8 9046	8 9046	8 9046	8 9046	8 9046	8 9046
9 Average ratio between energy intensity of electric and diesel trains (final energy)		ELTDRA	0 3551	0 3551	0 3551	0 3551	0 3551	0 3551	0 3551
10 Energy intensity of barges (kcal/t-km)		DBA	0 0	0 0	0 0	0 0	0 0	0 0	0 0
11 Energy intensity of pipelines (kcal/t-km)		DPIP	30 77	31 5	32 2	32 9	33 6	34 3	35 0
12 Average intercity distance travelled per person per year (km/per/yr)	R	DI	1279 707	1276	1327	1441	1622	1889	2269
	O		1279 707	1276	1391	1657	2046	2615	3446
	C		1279 707	1276	1267	1283	1336	1433	1566
	E		1279 707	1276	1327	1441	1622	1889	2269

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
13 Average intracity distance travelled per person per year (km/per/yr)	R	DU	7 521	7 9	8 31	8 730	9 180	9 640	10 14
	O		7 521	7 9	8 71	10 04	11 58	13 35	15 40
	C		7 521	7 9	7 94	7 770	7 560	7 310	7 000
	E		7 521	7 9	8 31	8 730	9 180	9 640	10 14
14 Inverse of car ownership ratio (pop/cars)	R	CO	114 83	87 70	67 10	50 70	38 20	28 70	21 60
	O		114 83	87 70	64 16	44 16	30 59	20 73	14 00
	C		114 83	87 70	70 42	57 05	46 85	37 83	30 80
	E		114 83	87 70	67 10	50 70	38 20	28 70	21 60
15 Average intercity distance driven per car per year (km/car/yr)	R	DIC	2976 46	3128	3287	3455	3631	3817	4011
	O		2976 46	3128	3325	3535	3750	3960	4200
	C		2976 46	3128	3250	3385	3515	3655	3800
	E		2976 46	3128	3287	3455	3631	3817	4011
16 Average load factor of cars in intercity travel (person/car)		LFIC	3 0	2 95	2 90	2 85	2 80	2 75	2 70
17 Share of cars in the total demand for intracity (urban) passenger tranportation	R	UC	0 35251	0 369	0 385	0 401	0 417	0 434	0 450
	O		0 35251	0 369	0 385	0 401	0 417	0 434	0 450
	C		0 35251	0 369	0 385	0 401	0 417	0 434	0 450
	E		0 35251	0 369	0 375	0 381	0 387	0 393	0 400
18 Share of electric cars in the total intracity car travel		UCE	0 0	0 0	0 0	0 0	0 0	0 0	0 0
19 Average load factor of cars in intracity travel (person/car)		LFUC	2 8	2 75	2 70	2 65	2 60	2 56	2 52
20 Share of buses in intercity passenger travel excluding travel by car	R	PBU	0 86486	0 86118	0 852	0 847	0 842	0 837	0 832
	O		0 86486	0 86118	0 852	0 847	0 842	0 837	0 832
	C		0 86486	0 86118	0 852	0 847	0 842	0 837	0 832
	E		0 86486	0 86118	0 850	0 8338	0 826	0 814	0 802
21 Share of trains in intercity passenger travel excluding by car	R	PTRA	0 11762	0 11592	0 120	0 120	0 120	0 120	0 120
	O		0 11762	0 11592	0 120	0 120	0 120	0 120	0 120
	C		0 11762	0 11592	0 120	0 120	0 120	0 120	0 120
	E		0 11762	0 11592	0 122	0 129	0 136	0 143	0 150
22 Share of electric trains in the total intercity travel by train	R	TRAEP	0 0395	0 04	0 06	0 080	0 110	0 14	0 18
	O		0 0395	0 04	0 06	0 080	0 110	0 14	0 18
	E		0 0395	0 04	0 06	0 080	0 110	0 14	0 18
	C		0 0395	0 04	0 07	0 110	0 150	0 20	0 25
23 Share of steam trains in the total intercity travel by train		TRASTP	0 0423	0 02	0 01	0 0	0 0	0 0	0 0
24 Share of air planes in intercity passenger travel excluding travel by car		PLA	0 01752	0 0229	0 028	0 033	0 038	0 043	0 048
25 Average load factor of buses (intercity) (pers/bus)		LFBU	43 7	42 9	42 1	41 3	40 5	39 7	39 0
26 Average load factor of trains (intercity) (pers/train)		LFTRA	507	498	489	480	471	463	455
27 Average capacity utilization factor of air planes		LFP	0 65	0 65	0 65	0 65	0 65	0 65	0 65

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
28 Share of mass transportation systems in intracity traffic	R	UMT	0 64749	0 631	0 615	0 599	0 583	0 566	0 55
	O		0 64749	0 631	0 615	0 599	0 583	0 566	0 55
	C		0 64749	0 631	0 615	0 599	0 583	0 566	0 55
	E		0 64749	0 631	0 625	0 619	0 613	0 607	0 60
29 Fraction of intracity traffic performed by electric modes	R	UMTE	0 0	0 0	0 01	0 02	0 04	0 07	0 1
	O		0 0	0 0	0 01	0 02	0 04	0 07	0 1
	C		0 0	0 0	0 01	0 02	0 04	0 07	0 1
	E		0 0	0 0	0 02	0 05	0 09	0 14	0 2
30 Average load factor of intracity buses (pers/bus)		LFMTB	54 849	53 93	53 0	52 08	51 17	50 26	49 36
31 Average load factor of electric mass transit system (intracity) (pers/veh)		LFMTE	58 4	57 4	56 40	55 40	54 40	53 40	52 50
32 Specific gasoline consumption of cars in intercity travel (liter/100 vehicle-km)	R	GIC	9 766	9 6	9 43	9 27	9 11	8 95	8 79
	O		9 766	9 6	9 43	9 27	9 11	8 95	8 79
	C		9 766	9 6	9 43	9 27	9 11	8 95	8 79
	E		9 766	9 1	8 47	7 88	7 33	6 82	6 35
33 Specific gasoline consumption of cars in intracity travel (liter/100 vehicle-km)	R	GUC	11 638	11 44	11 24	11 04	10 85	10 66	10 47
	O		11 638	11 44	11 24	11 04	10 85	10 66	10 47
	C		11 638	11 44	11 24	11 04	10 85	10 66	10 47
	E		11 638	10 91	10 20	9 510	8 840	8 190	7 560
34 Specific electricity consumption of electric cars (intracity) (kW h/ vehicle-km)		ELUC	0 0	0 0	0 0	0 0	0 0	0 0	0 0
35 Specific diesel consumption of intercity buses (liter/100 vehicle-km)	R	DBU	33 322	32 70	32 1	31 50	31 0	30 50	30 0
	O		33 322	32 70	32 1	31 50	31 0	30 50	30 0
	C		33 322	32 70	32 1	31 50	31 0	30 50	30 0
	E		33 322	31 72	30 2	28 76	27 4	26 12	25 0
36 Specific diesel consumption of diesel passenger train (intercity) (kcal//train-km)	R	DTRAP	36707 5	36095	35483	34871	34259	33647	33035
	O		36707 5	36095	35483	34871	34259	33647	33035
	C		36707 5	36095	35483	34871	34259	33647	33035
	E		36707 5	35915	35128	34174	33231	32301	31383
37 Specific energy consumption of air planes (kcal/seat-km)	R	DPLA	647 98	637	626	615	605	595	585
	O		647 98	637	626	615	605	595	585
	C		647 98	637	626	615	605	595	585
	E		647 98	579	514	452	393	337	285
38 Specific diesel consumption of buses (intracity) (liter/100 vehicle-km)	R	DMT	39 986	39 32	38 64	37 97	37 31	36 65	35 99
	O		39 986	39 32	38 64	37 97	37 31	36 65	35 99
	C		39 986	39 32	38 64	37 97	37 31	36 65	35 99
	E		39 986	38 08	36 28	34 58	32 98	31 48	30 00
39 Specific electricity consumption of intracity mass tranportation sytems (kW·h/ vehicle-km)		ELMT	0 0	0 0	3 4	3 4	3 4	3 4	3 4

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
E Household/Service									
1 Specific energy consumption for cooking in									
dwellings	R	COOKDW	2066 138	2120 691	2169 38	2212 00	2248 70	2280 610	2310 797
(in useful energy terms)	O		2066 138	2120 691	2175 20	2224 25	2269 549	2312 109	2351 170
(10^3 kcal/dw/yr)	C		2066 138	2120 691	2153 15	2184 45	2215 057	2243 589	2270 352
	E		2066 138	2089 015	2110 66	2131 12	2149 973	2167 223	2183 252
2 Share of dwellings with hot	R	DWHW	0 315	0 335	0 35	0 37	0 388	0 402	0 414
water heating	O		0 315	0 335	0 36	0 38	0 405	0 425	0 440
	C		0 315	0 335	0 34	0 36	0 378	0 390	0 400
	E		0 315	0 335	0 35	0 37	0 388	0 402	0 414
3 Specific energy consumption for water heating per person (useful energy)									
	R	HWCAP	43 9546	53 5754	65 764	82 317	104 3058	133 4899	172 0833
(10^3 kcal/dw/yr)	O		43 9546	53 5754	68 945	94 674	131 5458	184 8051	261 3237
	C		43 9546	53 5754	62 811	73 279	85 8974	101 2676	118 7820
	E		43 9546	53 5754	65 764	82 317	104 3058	133 4899	172 0833
4 Share of dwellings with air conditioning									
	R	DWAC	0 0104	0 0143	0 019	0 028	0 0404	0 0585	0 0854
	O		0 0104	0 0143	0 022	0 035	0 0573	0 0933	0 1530
	C		0 0104	0 0143	0 017	0 022	0 0282	0 0363	0 0471
	E		0 0104	0 0143	0 019	0 028	0 0404	0 0585	0 0854
5 Specific cooling requirements per dwelling									
	R	ACDW	4402 113	5445 108	6573 09	7742 92	8899 463	9979 253	10915 822
(10^3 kcal/dw/yr)	O		4402 113	5445 108	6573 09	7742 92	8899 463	9979 253	10915 822
	C		4402 113	5445 108	6573 09	7742 92	8899 463	9979 253	10915 822
	E		4402 113	5354 356	6353 99	7355 77	8306 166	9147 649	9824 2939
6 Specific (final) electricity consumption per dwelling for uses other than space/water									
heating, cooking and air	R	ELAPDW	1328 5	1467 366	1619 69	1796 57	2016 343	2290 197	2616 303
conditioning (kW·h/dw/yr)	O		1328 5	1467 366	1649 72	1904 31	2303 794	2811 967	3480 183
	C		1328 5	1467 366	1591 65	1715 63	1844 800	1967 104	2117 489
	E		1328 5	1467 366	1568 73	1683 88	1829 255	2018 505	2242 848
7 Electricity penetration in households for uses other than space/water heating, cooking and air conditioning									
	R	PEL	0 5682	0 6521	0 754	0 891	1 0	1 0	1 0
	O		0 5682	0 6521	0 783	0 999	1 0	1 0	1 0
	C		0 5682	0 6521	0 736	0 826	0 9164	1 0	1 0
	E		0 5682	0 6521	0 754	0 891	1 0	1 0	1 0
8 Coefficient of total "losses" in the electric									
network	R	ELOSS	1 3359	1 2346	1 212	1 190	1 1905	1 1905	1 1905
	O		1 3359	1 2346	1 212	1 190	1 1905	1 1905	1 1905
	C		1 3359	1 2346	1 212	1 190	1 1905	1 1905	1 1905
	E		1 3359	1 2346	1 190	1 149	1 1494	1 1494	1 1494
9 Fraction of "Old" dwellings per type									
1 Single family house centrally heated		PREDW(1)	0 0	0 0	0	0	0 0	0 0	0 0
2 Apartment with central heating		PREDW(2)	0 0	0 0	0	0	0 0	0 0	0 0
3 Dwelling with room heating only	R	PREDW(3)	0 02105	0 0400	0 070	0 110	0 1600	0 2250	0 3000
	O		0 02105	0 0400	0 095	0 155	0 2250	0 3050	0 4000
	C		0 02105	0 0400	0 061	0 087	0 1213	0 1600	0 2000
	E		0 02105	0 0400	0 070	0 110	0 1600	0 2250	0 3000

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description	Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-1	2022-23
10 Share of service sector floor								
area actually heated R	AREAH	0 500	0 525	0 550	0 575	0 600	0 62	0 650
O		0 500	0 525	0 558	0 592	0 628	0 66	0 700
C		0 500	0 525	0 541	0 557	0 573	0 58	0 600
E		0 500	0 525	0 550	0 575	0 600	0 62	0 650
11 Specific electricity consumption in "Old"								
R	ELARO	33 0	34 0	35 00	36 000	37 000	38 00	39 00
service sectors buildings O		33 0	34 0	35 60	37 200	38 800	40 40	42 00
(kW h/m^2/yr) C		33 0	34 0	34 60	35 200	35 800	36 40	37 00
E		33 0	33 32	33 04	32 688	32 264	31 76	31 20
12 Share of air conditioned								
service floor area R	AREAAC	0 0500	0 0647	0 0833	0 1084	0 1443	0 195	0 2691
O		0 0500	0 0647	0 0888	0 1252	0 1801	0 264	0 3917
C		0 0500	0 0647	0 0781	0 0960	0 1181	0 147	0 1875
E		0 0500	0 0647	0 0833	0 1084	0 1443	0 195	0 2691
13 Specific cooling requirements in the service sector								
(10^3 kcal m^2/yr) R	ACAREA	302 7	307 745	312 79	317 835	322 88	327 92	332 97
O		302 7	307 745	321 79	317 835	322 88	327 92	332 97
C		302 7	307 745	321 79	317 835	322 88	327 92	332 97
E		302 7	280 5512	259 4571	239 3442	220 1455	201 80	184 2522
14 Coefficient of performance of (elect.) air								
conditioners R	EFFAC	2 0	2 0333	2 0667	2 100	2 1333	2 166	2 2
O		2 0	2 0333	2 0667	2 100	2 1333	2 166	2 2
C		2 0	2 0333	3 0667	2 100	2 1333	2 166	2 2
E		2 0	2 0500	2 1000	2 150	2 2000	2 250	2 3
15 Average demolition rate of dwellings over a 5-year period between previous and current years	DEMDW	0 00	0 05	0 07	0 09	0 11	0 1	0 15
16 Distribution of dwellings constructed between the last previous and current years by dwelling type								
1 Single family house centrally heated	NEWDW(1)	0 0	0 0	0 0	0 0	0 0	0	0 0
2 Apartment with central heating	NEWDW(2)	0 0	0 0	0 0	0 0	0 0	0	0 0
3 Dwelling with room heating only R	NEWDW(3)	0 0	0 10	0 20	0 30	0 40	0 5	0 60
O		0 0	0 10	0 22	0 34	0 46	0 5	0 70
C		0 0	0 10	0 18	0 26	0 34	0 4	0 50
E		0 0	0 10	0 20	0 30	0 40	0 5	0 60
17 Average floor area heated in "New"	DWS(1)	0 0	0 0	0 0	0 0	0 0	0	0 0
dwellings (definition of dwelling types	DWS(2)	0 0	0 0	0 0	0 0	0 0	0	0 0
as for NEWDW above (m^2/dw)	DWS(3)	0 0	35 0	35 0	35 0	35 0	35	35 0
18 Specific heat loss rate in "New" dwellings	K(1)	0 0	0 0	0 0	0 0	0 0	0	0 0
(definition of dwelling types as for	K(2)	0 0	0 0	0 0	0 0	0 0	0	0 0
NEWDW above) R	K(3)	0 0	6 143	5 7	5 3	4 9	4	4 1
(kcal/m^2/^{o} C/h) O		0 0	6 143	5 7	5 3	4 9	4	4 1
C		0 0	6 143	5 7	5 3	4 9	4	4 1
E		0 0	6 143	5 5	5 0	4 5	4	3 5

Table B.6 MAED Parameters
B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
19 Reduction of the average rate space heat demand of "Old" dwellings in current year									
relative to that in the base year due to better		ISO(1)	0 0	0 0	0 0	0 0	0 0	0 0	0 0
insulation (definition of dwelling types as		ISO(2)	0 0	0 0	0 0	0 0	0 0	0 0	0 0
for PREDW above)		ISO(3)	0 0	0 0	0 0	0 0	0 0	0 0	0 0
20 Average floor area per									
employee in the service	R	AREAL	10 00	10 75	11 50	12 25	13 0	13 75	14 50
sector (m^2/employ)	O		10 00	10 75	11 80	12 85	13 9	14 95	16 00
	C		10 00	10 75	11 20	11 65	12 1	12 55	13 00
	E		10 00	10 75	11 50	12 25	13 0	13 75	14 50
21 Average demolition rate on the floor area of service sector buildings over a 5-year period between previous and current year		DEMAR	0 000	0 025	0 030	0 040	0 050	0 060	0 070
22 Specific heat requiremnets of "New" service buildings (useful energy) (10^3 kcal/m^2/yr)									
	R	HAREAN	-	65 0	65 0	65 0	65 0	65 0	65 0
	O		-	65 0	65 0	65 0	65 0	65 0	65 0
	C		-	65 0	65 0	65 0	65 0	65 0	65 0
	E		-	65 0	63 0	61 0	59 0	57 0	55 0
23 Specific electricity consumption in "New									
	R	ELARN	0 0	40 0	41 0	42 0	43 0	44 0	45 0
service sector	O		0 0	40 0	41 8	43 6	45 4	47 2	49 0
buildings (kW h/m^2/yr)			0 0	40 0	40 4	40 8	41 2	41 6	42 0
C			0 0	39 2	38 704	38 136	37 496	36 784	36 0
	E								
24 Reduction of the average heat demand in "Old" service sector buildings in current year relative to that in the base year due to better insulation		ISOSV	0 0	0 0	0 0	0 0	0 0	0 0	0 0
25 Electricity penetration into thermal uses in the Household/Service sector									
		ELP H SH	0 05	0 056	0 625	0 70	0 80	0 90	0 100
H SH= Space heating (households)									
		ELP H HW	0 000	0 001	0 002	0 004	0 007	0 012	0 020
H HW= Water heating (households)									
		ELP H CK	0 0	0 0	0 0	0 0	0 0	0 0	0 0
H CK= Cooking (household)									
S TH= Thermal uses		ELP S TH	0 060	0 065	0 072	0 080	0 090	0 102	0 115
service sector)	R		0 060	0 065	0 072	0 080	0 090	0 102	0 115
	O		0 060	0 065	0 072	0 080	0 090	0 102	0 115
	C		0 060	0 075	0 090	0 105	0 120	0 135	0 150
	E								
26 Contribution of heat pump to electric space and water heating in the Household/Service sector		HPHS	0 0	0 0	0 0	0 0	0 0	0 0	0 0
27 Coefficient of performance of (electric) heat pumps in the Household/Service sector		EFFHPR	2 0	2 0	2 0	2 0	2 0	2 0	2 0
28 District heat penetration into space and water heating of dwellings and thermal uses in Service sector		DHPH	0 0	0 0	0 0	0 0	0 0	0 0	0 0
29 Solar penetration into space heating in "New" single family houses with central heating		SPSH	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Table B.6 MAED Parameters

B. Input Time Dependent Parameters and Value (cont.)

Description		Variable	1992-93	1997-98	2002-03	2007-08	2012-13	2017-18	2022-23
30 Approximate share of space heat demand in households that can be met by a solar installation		FDSHS	0 0	0 0	0 0	0 0	0 0	0	0 0
31 Solar penetration into water heating in dwellings	R	SPHW	0 0000	0 0005	0 001	0 0025	0 0045	0 007	0 011
	O		0 0000	0 0005	0 001	0 0025	0 0045	0 007	0 011
	C		0 0000	0 0005	0 001	0 0025	0 0045	0 007	0 011
	E		0 0000	0 0006	0 002	0 0060	0 0150	0 030	0 050
32 Approximate share of the hot water demand in households that can be met by solar installation		FDHWS	0 70	0 69	0 67	0 64	0 60	0 5	0 50
33 Share of low-rise buildings (e g up to 3 floors) in total Service sector floor area		PLB	0 5	0 5	0 5	0 5	0 5	0	0 5
34 Solar penetration into thermal uses in "NEW" low-rise Service sector buildings		SPSV	0 0	0 0	0 0	0 0	0 0	0	0 0
35 Approximation share of the thermal energy demand in Services that can be met by a solar installation		FDHS	0 0	0 0	0 0	0 0	0 0	0	0 0
36 Ratio of the amount of Non-commercial fuels used in the current year relative to that in the base year		CHGNCF	1 0000	1 1593	1 3116	1 4481	1 56	1 639	1 681
37 Efficiency of fossil fuel use relative to that of electricity use for thermal uses in the Household and Service sectors									
H SH= Space heating (households)	R	EFF H SH	0 60	0 61	0 62	0 63	0 64	0 6	0 66
	O		0 60	0 61	0 62	0 63	0 64	0 6	0 66
	C		0 60	0 61	0 62	0 63	0 64	0 6	0 66
	E		0 60	0 6167	0 6333	0 65	0 6667	0 683	0 70
H HW= Water heating (households)	R	EFF H HW	0 60	0 61	0 62	0 63	0 64	0 6	0 66
	O		0 60	0 61	0 62	0 63	0 64	0 6	0 66
	C		0 60	0 61	0 62	0 63	0 64	0 6	0 66
	E		0 60	0 6167	0 6333	0 65	0 6667	0 683	0 70
H CK= Cooking (household)	R	EFF H CK	0 592	0 61	0 62	0 63	0 64	0 6	0 66
	O		0 592	0 61	0 62	0 63	0 64	0 6	0 66
	C		0 592	0 61	0 62	0 63	0 64	0 6	0 66
	E		0 592	0 61	0 628	0 646	0 664	0 68	0 70
S TH= Thermal uses (service sector)	R	EFF S TH	0 531	0 55	0 56	0 58	0 59	0 6	0 62
	O		0 531	0 55	0 56	0 58	0 59	0 6	0 62
	C		0 531	0 55	0 56	0 58	0 59	0 6	0 62
	E		0 531	0 5508	0 5707	0 5905	0 6130	0 630	0 65
38 Efficiency of non-commercial fuel use relative to that of thermal electricity uses	R	EFFNCF	0 130	0 135	0 140	0 145	0 150	0 15	0 160
	O		0 130	0 135	0 140	0 145	0 150	0 15	0 160
	C		0 130	0 135	0 140	0 145	0 150	0 15	0 160
	E		0 130	0 1383	0 1467	0 155	0 1630	0 171	0 180

Note: R = REFERENCE SCENARIO . O = OPTIMISTIC SCENARIO
C = CONSTRAINED SCENARIO . E = ENERGY EFFICIENCY SCENARI

Appendix C

COMPUTER OUTPUT OF MODULE 1 OF MAED FOR THE REFERENCE SCENARIO

This Appendix contains the computer output of module 1 of MAED for the Reference scenario. Due to limitations of the model some projections have been made outside the MAED model. These projections are for:

(a) Non-energy oils,
(b) Gas feed-stocks used in the fertilizer industry,
(c) Electricity use in transportation of oil products through pipelines,
(d) Bagasse use in sugar industry, and
(e) Kerosene use for lighting in households.

To include the above listed projections in the results of the MAED model some modifications have been made in the MAED source programme and Tables 10A and 10B have been added in the output of the MAED model.

Appendix C

COMPUTER OUTPUT OF MODULE 1 OF MAED FOR THE REFERENCE SCENARIO

SUMMARY OF INPUTS (SCENARIO VARIABLES) INTO MAED/TABLE 1A:

PRINCIPAL VARIABLES CHANGED FROM ONE SCENARIO TO ANOTHER
VALUES AS FRACTIONS EXCEPT WHEN INDICATED OTHERWISE

YEAR:	1993	1998	2003	2008	2013	2018	2023
VARIABLES RELATED TO THE INDUSTRIAL SECTOR:							
RATIO OF ELECTRICITY INTENSITY VS BASE YEAR IN:							
- AGRICULTURE	1.000	.878	.754	.662	.577	.491	.416
- CONSTRUCTION	1.000	2.010	3.540	5.710	8.780	13.210	19.410
- MINING	1.000	1.000	1.000	1.000	1.000	1.000	1.000
- MANUFACTURING	1.000	1.060	1.093	1.121	1.138	1.148	1.150
SHARE OF USEFUL THERMAL ENERGY WHICH IS SUPPLIED BY ELECTRICITY IN MANUFACTURING FOR PROCESS:							
- FURNACE/DIRECT HEAT	.000	.002	.010	.030	.060	.080	.100
- SPACE/WATER HEATING	.000	.000	.000	.000	.000	.000	.000
CONTRIBUTION OF ELECTRIC HEAT PUMPS TO LOW-TEMPERATURE HEAT PRODUCTION:	.000	.000	.000	.000	.000	.000	.000
SHARE OF MANUFACTURING DEMAND FOR L.T. STEAM AND HOT WATER WHICH IS SUPPLIED BY SOLAR:	.000	.000	.001	.002	.005	.010	.020
COKE INPUT IN BLAST FURNACES PER UNIT OUTPUT OF PIG IRON (KG COKE/TON PIG IRON)	905.000	870.000	835.000	800.000	765.000	730.000	700.000
VARIABLES RELATED TO THE TRANSPORTATION SECTOR:							
SHARE OF ELECTRIC TRAINS IN:							
- TOTAL FREIGHT TRANSPORTATION BY RAIL	.030	.030	.045	.065	.090	.120	.160
- TOTAL INTERCITY TRAVEL BY TRAIN	.040	.040	.060	.080	.110	.140	.180
SHARE OF ELECTRIC MASS TRANSIT IN TOTAL INTRACITY MASS TRANSPORTATION:	.000	.000	.010	.020	.040	.070	.100
VARIABLES RELATED TO HOUSEHOLD/SERVICE SECTOR:							
SPECIFIC ELECTRICITY CONSUMPTION IN:							
- DWELLINGS FOR USES OTHER THAN SPACE/WATER HEATING, COOKING AND A.C. (KWH/YR/DW)	1328.500	1467.366	1619.691	1796.571	2016.343	2290.197	2616.303
- OLD-SERVICE SECTOR BUILDINGS (KWH/YR/SQM)	33.000	34.000	35.000	36.000	37.000	38.000	39.000
- NEW-SERVICE SECTOR BUILDINGS (KWH/YR/SQM)	.000	40.000	41.000	42.000	43.000	44.000	45.000
ELECTRICITY PENETRATION INTO THERMAL USES FOR:							
- SPACE HEATING HOUSEHOLDS	.050	.056	.063	.070	.080	.090	.100
- WATER HEATING HOUSEHOLDS	.000	.001	.002	.004	.007	.012	.020
- COOKING HOUSEHOLDS	.000	.000	.000	.000	.000	.000	.000
- THERMAL USES SERVICE SECTOR	.060	.065	.072	.080	.090	.102	.115
CONTRIBUTION OF HEAT PUMPS TO ELECTRIC SPACE AND WATER HEATING	.000	.000	.000	.000	.000	.000	.000
COEFFICIENT OF LOSSES OF ELECTRIC NETWORK:	1.336	1.235	1.212	1.191	1.191	1.191	1.191

SUMMARY OF RESULTS OF MAED/TABLE 1B:
****

BASIC INPUT INFORMATION:	1993	1998	2003	2008	2013	2018	2023
POPULATION:							
TOTAL (MILLION PEOPLE)	120.830	138.920	158.640	177.740	196.720	215.610	234.570
AVERAGE ANNUAL GROWTH RATE							
VERSUS BASE YEAR (%)	.000	2.830	2.760	2.606	2.467	2.343	2.236
G.D.P.:							
TOTAL (10**9 MONETARY UNITS OF BASE YEAR)	1200.455	1682.313	2358.160	3307.144	4638.029	6505.471	9123.756
AVERAGE ANNUAL GROWTH RATE							
VERSUS BASE YEAR (%)	.000	6.982	6.985	6.989	6.992	6.993	6.994
PER CAPITA (10**3 MU/CAP)	9.935	12.110	14.865	18.607	23.577	30.172	38.896
FINAL ENERGY RESULTS:							
COMMERCIAL ENERGY:							
TOTAL (GWYR)	31.554	42.960	60.185	84.548	118.694	167.065	236.841
AVERAGE ANNUAL GROWTH RATE							
VERSUS BASE YEAR (%)	.000	6.366	6.670	6.792	6.849	6.894	6.950
PER CAPITA (KWYR/CAP)	.261	.309	.379	.476	.603	.775	1.010
ELECTRICITY DEMAND:							
TOTAL (GWYR)	4.153	6.340	9.698	15.070	23.150	34.143	50.482
(TWHR)	36.381	55.540	84.958	132.015	202.791	299.094	442.223
AVERAGE ANNUAL GROWTH RATE							
VERSUS BASE YEAR (%)	.000	8.829	8.851	8.972	8.970	8.792	8.682
PER CAPITA (KWYR/CAP)	.034	.046	.061	.085	.118	.158	.215
(KWHR/CAP)	301.096	399.798	535.540	742.744	1030.861	1387.199	1885.248
RATIO OF ELECTRICITY TO ENERGY	.132	.148	.161	.178	.195	.204	.213

DETAILED RESULTS OF MAED/TABLE 2 :
****

FINAL ENERGY RESULTS (MTOE):	1993	1998	2003	2008	2013	2018	2023
BY SECTOR:							
AGR/CONSTR/MIN/MAN.(INCL.FEEDST.)	13.303	19.158	27.912	40.572	58.726	85.689	125.531
TRANSPORTATION	5.276	6.226	7.740	9.721	12.432	16.056	20.971
HOUSEHOLD/SERVICE (EXCL.NON-COMM.)	3.921	5.248	7.263	9.993	13.475	17.380	22.376
TOTAL COMMERCIAL (INCL.FEEDST.)	22.499	30.632	42.914	60.286	84.634	119.124	168.878
BY ENERGY FORM:							
FOSSIL (SUBST.)	11.640	16.562	23.964	34.236	48.311	68.716	97.913
CENTRALIZED HEAT SUPPLY	.000	.000	.000	.000	.000	.000	.000
SOFT SOLAR	.000	.000	.002	.011	.037	.107	.312
ELECTRICITY	2.961	4.521	6.915	10.746	16.507	24.345	35.996
MOTOR FUEL	7.196	8.616	10.690	13.340	16.923	21.779	28.524
COAL, SPEC.USES	.702	.933	1.343	1.953	2.856	4.177	6.133
FEEDSTOCKS	.000	.000	.000	.000	.000	.000	.000
TOTAL COMMERCIAL (INCL.FEEDST.)	22.499	30.632	42.914	60.286	84.634	119.124	168.878
NON-COMMERCIAL FUELS	18.231	21.135	23.912	26.400	28.440	29.892	30.646
TOTAL (COMMERCIAL+NON-COMMERCIAL)	40.730	51.767	66.826	86.686	113.074	149.016	199.524

FINAL ENERGY RESULTS (%):	1993	1998	2003	2008	2013	2018	2023
BY SECTOR:							
AGR/CONSTR/MIN/MAN.(INCL.FEEDST.)	59.1	62.5	65.0	67.3	69.4	71.9	74.3
TRANSPORTATION	23.4	20.3	18.0	16.1	14.7	13.5	12.4
HOUSEHOLD/SERVICE (EXCL.NON-COMM.)	17.4	17.1	16.9	16.6	15.9	14.6	13.2
TOTAL COMMERCIAL (INCL.FEEDST.)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BY ENERGY FORM:							
FOSSIL (SUBST.)	51.7	54.1	55.8	56.8	57.1	57.7	58.0
CENTRALIZED HEAT SUPPLY	00.0	00.0	00.0	00.0	00.0	00.0	00.0
SOFT SOLAR	00.0	00.0	00.0	00.0	00.0	.1	.2
ELECTRICITY	13.2	14.8	16.1	17.8	19.5	20.4	21.3
MOTOR FUEL	32.0	28.1	24.9	22.1	20.0	18.3	16.9
COAL, SPEC.USES	3.1	3.0	3.1	3.2	3.4	3.5	3.6
FEEDSTOCKS	00.0	00.0	00.0	00.0	00.0	00.0	00.0
TOTAL COMMERCIAL (INCL.FEEDST.)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
NON-COMMERCIAL FUELS	81.0	69.0	55.7	43.8	33.6	25.1	18.1
TOTAL (COMMERCIAL+NON-COMMERCIAL)	181.0	169.0	155.7	143.8	133.6	125.1	118.1

DETAILED RESULTS OF MAED/TABLE 3A:
****

FINAL ENERGY RESULTS (MTOE):	1993	1998	2003	2008	2013	2018	2023
AGR/CONSTR/MIN/MAN.:							
FOSSIL (SUBST.)	9.167	13.444	19.850	28.923	41.530	60.218	87.400
CENTRALIZED HEAT SUPPLY	.000	.000	.000	.000	.000	.000	.000
SOFT SOLAR	.000	.000	.001	.010	.035	.103	.303
ELECTRICITY	1.511	2.388	3.759	6.050	9.776	15.392	24.009
MOTOR FUEL	1.967	2.416	2.972	3.637	4.529	5.799	7.686
METALL.COKE	.658	.910	1.329	1.953	2.856	4.177	6.133
FEEDSTOCKS	.000	.000	.000	.000	.000	.000	.000
TOTAL (INCL.FEEDST.)	13.303	19.158	27.912	40.572	58.726	85.689	125.531
OF WHICH MANUFACTURING:							
FOSSIL (SUBST.)	9.167	13.444	19.850	28.923	41.530	60.218	87.400
CENTRALIZED HEAT SUPPLY	.000	.000	.000	.000	.000	.000	.000
SOFT SOLAR	.000	.000	.001	.010	.035	.103	.303
ELECTRICITY	1.050	1.872	3.204	5.449	9.126	14.696	23.251
MOTOR FUEL	.073	.119	.191	.302	.471	.726	1.110
METALL.COKE	.658	.910	1.329	1.953	2.856	4.177	6.133
FEEDSTOCKS	.000	.000	.000	.000	.000	.000	.000
TOTAL (INCL.FEEDST.)	10.948	16.345	24.576	36.637	54.017	79.919	118.197
TRANSPORTATION:							
ELECTRICITY	.002	.003	.009	.018	.038	.075	.133
MOTOR FUEL	5.229	6.200	7.717	9.703	12.394	15.980	20.838
STEAM COAL	.044	.023	.014	.000	.000	.000	.000
TOTAL	5.276	6.226	7.740	9.721	12.432	16.056	20.971
HOUSEHOLD/SERVICE:							
FOSSIL (SUBST.)	2.473	3.118	4.114	5.314	6.781	8.498	10.513
CENTRALIZED HEAT SUPPLY	.000	.000	.000	.000	.000	.000	.000
SOFT SOLAR	.000	.000	.000	.001	.002	.005	.009
ELECTRICITY	1.448	2.130	3.148	4.678	6.693	8.878	11.854
TOTAL COMMERCIAL	3.921	5.248	7.263	9.993	13.475	17.380	22.376
NON-COMMERCIAL	18.231	21.135	23.912	26.400	28.440	29.892	30.646
TOTAL (COMM.+NON-COMM.)	22.152	26.384	31.174	36.393	41.916	47.271	53.022

DETAILED RESULTS OF MAED/TABLE 3B:
****

FINAL ENERGY RESULTS (%):	1993	1998	2003	2008	2013	2018	2023
AGR/CONSTR/MIN/MAN.:							
FOSSIL (SUBST.)	68.9	70.2	71.1	71.3	70.7	70.3	69.6
CENTRALIZED HEAT SUPPLY	00.0	00.0	00.0	00.0	00.0	00.0	00.0
SOFT SOLAR	00.0	00.0	00.0	00.0	.1	.1	.2
ELECTRICITY	11.4	12.5	13.5	14.9	16.6	18.0	19.1
MOTOR FUEL	14.8	12.6	10.6	9.0	7.7	6.8	6.1
METALL.COKE	4.9	4.8	4.8	4.8	4.9	4.9	4.9
FEEDSTOCKS	00.0	00.0	00.0	00.0	00.0	00.0	00.0
TOTAL (INCL.FEEDST.)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
OF WHICH MANUFACTURING:							
FOSSIL (SUBST.)	83.7	82.2	80.8	78.9	76.9	75.3	73.9
CENTRALIZED HEAT SUPPLY	00.0	00.0	00.0	00.0	00.0	00.0	00.0
SOFT SOLAR	00.0	00.0	00.0	00.0	.1	.1	.3
ELECTRICITY	9.6	11.5	13.0	14.9	16.9	18.4	19.7
MOTOR FUEL	.7	.7	.8	.8	.9	.9	.9
METALL.COKE	6.0	5.6	5.4	5.3	5.3	5.2	5.2
FEEDSTOCKS	00.0	00.0	00.0	00.0	00.0	00.0	00.0
TOTAL (INCL.FEEDST.)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TRANSPORTATION:							
ELECTRICITY	00.0	00.0	.1	.2	.3	.5	.6
MOTOR FUEL	99.1	99.6	99.7	99.8	99.7	99.5	99.4
STEAM COAL	.8	.4	.2	00.0	00.0	00.0	00.0
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0
HOUSEHOLD/SERVICE:							
FOSSIL (SUBST.)	63.1	59.4	56.6	53.2	50.3	48.9	47.0
CENTRALIZED HEAT SUPPLY	00.0	00.0	00.0	00.0	00.0	00.0	00.0
SOFT SOLAR	00.0	00.0	00.0	00.0	00.0	00.0	00.0
ELECTRICITY	36.9	40.6	43.3	46.8	49.7	51.1	53.0
TOTAL COMMERCIAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0
NON-COMMERCIAL	464.9	402.7	329.2	264.2	211.1	172.0	137.0
TOTAL (COMM.+NON-COMM.)	564.9	502.7	429.2	364.2	311.1	272.0	237.0

DETAILED RESULTS OF MAED/TABLE 4A:
****

FINAL ENERGY RESULTS (MTOE):	1993	1998	2003	2008	2013	2018	2023
FOSSIL (SUBST.):	11.640	16.562	23.964	34.236	48.311	68.716	97.913
AGR/CONSTR/MIN/MAN.	9.167	13.444	19.850	28.923	41.530	60.218	87.400
HOUSEHOLD/SERVICE	2.473	3.118	4.114	5.314	6.781	8.498	10.513
CENTRALIZED HEAT SUPPLY:	.000	.000	.000	.000	.000	.000	.000
AGR/CONSTR/MIN/MAN.	.000	.000	.000	.000	.000	.000	.000
HOUSEHOLD/SERVICE	.000	.000	.000	.000	.000	.000	.000
SOFT SOLAR:	.000	.000	.002	.011	.037	.107	.312
AGR/CONSTR/MIN/MAN.	.000	.000	.001	.010	.035	.103	.303
HOUSEHOLD/SERVICE	.000	.000	.000	.001	.002	.005	.009
ELECTRICITY:	2.961	4.521	6.915	10.746	16.507	24.345	35.996
AGR/CONSTR/MIN/MAN.	1.511	2.388	3.759	6.050	9.776	15.392	24.009
TRANSPORTATION	.002	.003	.009	.018	.038	.075	.133
HOUSEHOLD/SERVICE	1.448	2.130	3.148	4.678	6.693	8.878	11.854
MOTOR FUEL:	7.196	8.616	10.690	13.340	16.923	21.779	28.524
AGR/CONSTR/MIN/MAN.	1.967	2.416	2.972	3.637	4.529	5.799	7.686
TRANSPORTATION	5.229	6.200	7.717	9.703	12.394	15.980	20.838
COAL, SPEC.USES:	.702	.933	1.343	1.953	2.856	4.177	6.133
AGR/CONSTR/MIN/MAN.	.658	.910	1.329	1.953	2.856	4.177	6.133
TRANSPORTATION	.044	.023	.014	.000	.000	.000	.000
FEEDSTOCKS:							
AGR/CONSTR/MIN/MAN.	.000	.000	.000	.000	.000	.000	.000
ALL FORMS (EXCL.NON-COMM.):	22.499	30.632	42.914	60.286	84.634	119.124	168.878
AGR/CONSTR/MIN/MAN.	13.303	19.158	27.912	40.572	58.726	85.689	125.531
TRANSPORTATION	5.276	6.226	7.740	9.721	12.432	16.056	20.971
HOUSEHOLD/SERVICE	3.921	5.248	7.263	9.993	13.475	17.380	22.376
NON-COMMERCIAL FUELS:							
HOUSEHOLDS	18.231	21.135	23.912	26.400	28.440	29.892	30.646

DETAILED RESULTS OF MAED/TABLE 4B:
****

FINAL ENERGY RESULTS (%):	1993	1998	2003	2008	2013	2018	2023
FOSSIL (SUBST.):	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	78.8	81.2	82.8	84.5	86.0	87.6	89.3
HOUSEHOLD/SERVICE	21.2	18.8	17.2	15.5	14.0	12.4	10.7
CENTRALIZED HEAT SUPPLY:	00.0	00.0	00.0	00.0	00.0	00.0	00.0
AGR/CONSTR/MIN/MAN.	00.0	00.0	00.0	00.0	00.0	00.0	00.0
HOUSEHOLD/SERVICE	00.0	00.0	00.0	00.0	00.0	00.0	00.0
SOFT SOLAR:	00.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	00.0	00.0	85.4	92.7	94.5	95.8	97.2
HOUSEHOLD/SERVICE	00.0	100.0	14.6	7.3	5.5	4.2	2.8
ELECTRICITY:	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	51.0	52.8	54.4	56.3	59.2	63.2	66.7
TRANSPORTATION	.1	.1	.1	.2	.2	.3	.4
HOUSEHOLD/SERVICE	48.9	47.1	45.5	43.5	40.5	36.5	32.9
MOTOR FUEL:	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	27.3	28.0	27.8	27.3	26.8	26.6	26.9
TRANSPORTATION	72.7	72.0	72.2	72.7	73.2	73.4	73.1
COAL, SPEC.USES:	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	93.7	97.5	99.0	100.0	100.0	100.0	100.0
TRANSPORTATION	6.3	2.5	1.0	00.0	00.0	00.0	00.0
FEEDSTOCKS:							
AGR/CONSTR/MIN/MAN.	00.0	00.0	00.0	00.0	00.0	00.0	00.0
ALL FORMS (EXCL.NON-COMM.):	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGR/CONSTR/MIN/MAN.	59.1	62.5	65.0	67.3	69.4	71.9	74.3
TRANSPORTATION	23.4	20.3	18.0	16.1	14.7	13.5	12.4
HOUSEHOLD/SERVICE	17.4	17.1	16.9	16.6	15.9	14.6	13.2
NON-COMMERCIAL FUELS:							
HOUSEHOLDS	100.0	100.0	100.0	100.0	100.0	100.0	100.0

DETAILED RESULTS OF MAED/TABLE 5 :
****

USEFUL/SPECIFIC ENERGY RESULTS (MTOE):	1993	1998	2003	2008	2013	2018	2023
AGR/CONSTR/MIN/MAN.:							
THERMAL USES, MAN. (USEFUL)	5.664	8.558	13.009	19.579	29.235	43.849	65.888
STEAM GENERATION	2.647	3.935	5.785	8.485	12.404	18.216	26.796
FURNACE	2.780	4.261	6.675	10.265	15.581	23.743	36.237
SPACE HEATING	.237	.362	.549	.830	1.250	1.889	2.855
THERMAL USES, AGR/CONSTR/MIN. (FINAL)	.000	.000	.000	.000	.000	.000	.000
SPECIFIC ELECTRICITY DEMAND (FINAL)	1.669	2.588	3.976	6.133	9.375	14.234	21.422
MOTOR FUEL (FINAL)	1.967	2.416	2.972	3.637	4.529	5.799	7.686
METALL.COKE (FINAL)	.658	.910	1.329	1.953	2.856	4.177	6.133
FEEDSTOCKS (FINAL)	.000	.000	.000	.000	.000	.000	.000
TRANSPORTATION:							
STEAM COAL (FINAL):	.044	.023	.014	.000	.000	.000	.000
FREIGHT	.000	.000	.000	.000	.000	.000	.000
PASSENGER, INTERCITY	.044	.023	.014	.000	.000	.000	.000
MOTOR FUEL (FINAL):	5.229	6.200	7.717	9.703	12.394	15.980	20.838
FREIGHT	2.407	2.609	3.099	3.742	4.646	5.892	7.589
PASSENGER, INTERCITY	1.409	1.759	2.254	2.946	3.924	5.320	7.316
PASSENGER, URBAN	1.022	1.401	1.877	2.448	3.145	3.931	4.875
MISCELLANEOUS	.390	.431	.488	.568	.680	.837	1.058
ELECTRICITY (FINAL):	.002	.003	.009	.018	.038	.075	.133
FREIGHT	.001	.001	.002	.004	.008	.017	.033
PASSENGER, INTERCITY	.002	.002	.003	.005	.009	.013	.022
PASSENGER, URBAN	.000	.000	.003	.009	.021	.045	.078
HOUSEHOLDS:							
USEFUL ENERGY:							
SPACE HEATING	.062	.166	.351	.598	.882	1.171	1.390
WATER HEATING	.158	.236	.350	.515	.753	1.095	1.582
COOKING	3.286	3.933	4.660	5.400	6.163	6.950	7.773
AIR CONDITIONING	.073	.144	.281	.533	.985	1.779	3.136
SECONDARY ELECTR. APPLIANCES (FINAL)	1.033	1.526	2.258	3.364	4.753	6.002	7.568
SERVICE SECTOR:							
USEFUL ENERGY:							
THERMAL USES	.316	.415	.546	.708	.896	1.112	1.356
AIR CONDITIONING	.150	.246	.403	.659	1.078	1.764	2.884
SPECIFIC ELECTRICITY DEMAND (FINAL)	.282	.375	.497	.646	.816	1.008	1.223

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 6 :
****

DEMOGRAPHIC AND MACRO-ECONOMIC INFORMATION:	1993	1998	2003	2008	2013	2018	2023
POPULATION (MILLION PEOPLE):	120.830	138.920	158.640	177.740	196.720	215.610	234.570
%IN CITIES	(19.5)	(21.5)	(23.4)	(25.3)	(27.3)	(29.1)	(31.0)
GDP/CAP. (10**3MU/CAP.)	9.935	12.110	14.865	18.607	23.577	30.172	38.896
PRIVATE CONSUMPTION/CAP. (10**3MU/CAP.)	.000	.000	.000	.000	.000	.000	.000
GDP EXPENDITURE (%):							
GROSS FIXED CAPITAL FORMATION	00.0	00.0	00.0	00.0	00.0	00.0	00.0
EQUIPMENT	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
CONSTRUCTION	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
PRIVATE CONSUMPTION	00.0	00.0	00.0	00.0	00.0	00.0	00.0
DURABLE GOODS	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
NON-DURABLE GOODS	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
SERVICES	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
GDP FORMATION (10**9 MU):	1200.455	1682.313	2358.160	3307.144	4638.029	6505.471	9123.756
AGRICULTURE	297.816	378.352	471.396	576.435	704.517	861.324	1052.881
CONSTRUCTION	49.807	72.508	101.637	142.538	199.899	280.386	393.234
MINING	7.403	12.617	20.516	31.418	48.236	74.813	114.959
MANUFACTURING	207.568	332.762	521.389	809.589	1245.775	1899.598	2869.421
ENERGY SECTOR	38.789	57.535	86.544	129.971	195.725	294.047	442.502
SERVICES (INCL.TRANSPORTATION)	599.071	828.539	1156.677	1616.863	2243.415	3095.303	4250.758
GDP FORMATION (%):	100.0	100.0	100.0	100.0	100.0	100.0	100.0
AGRICULTURE	24.8	22.5	20.0	17.4	15.2	13.2	11.5
CONSTRUCTION	4.1	4.3	4.3	4.3	4.3	4.3	4.3
MINING	.6	.7	.9	.9	1.0	1.2	1.3
MANUFACTURING	17.3	19.8	22.1	24.5	26.9	29.2	31.5
ENERGY SECTOR	3.2	3.4	3.7	3.9	4.2	4.5	4.9
SERVICES (INCL.TRANSPORTATION)	49.9	49.3	49.1	48.9	48.4	47.6	46.6
VA, MANUFACTURING (10**9 MU):	207.568	332.762	521.389	809.589	1245.775	1899.598	2869.421
BASIC MATERIALS	50.636	83.523	139.784	227.252	360.403	565.320	878.617
MACHINERY AND EQUIPMENT	14.262	29.716	59.230	111.561	201.317	351.046	592.249
CONSUMER GOODS	77.402	121.824	184.155	276.879	411.978	605.782	880.912
MISCELLANEOUS	65.268	97.699	138.220	193.816	272.077	377.450	517.931
VA, MANUFACTURING (%):	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BASIC MATERIALS	24.4	25.1	26.8	28.1	28.9	29.8	30.6
MACHINERY AND EQUIPMENT	6.9	8.9	11.4	13.8	16.2	18.5	20.6
CONSUMER GOODS	37.3	36.6	35.3	34.2	33.1	31.9	30.7
MISCELLANEOUS	31.4	29.4	26.5	23.9	21.8	19.9	18.1

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 7A:
****

ENERGY INTENSITY ASSUMPTIONS IN AGR/CONSTR/MIN/MAN.:

YEAR:	1993	1998	2003	2008	2013	2018	2023
AGRICULTURE:							
MOTOR FUEL (FINAL;KWH/MU)	.072	.066	.061	.055	.049	.043	.038
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.019	.017	.014	.013	.011	.009	.008
THERMAL (FINAL;KWH/MU)	.000	.000	.000	.000	.000	.000	.000
CONSTRUCTION:							
MOTOR FUEL (FINAL;KWH/MU)	.022	.024	.027	.029	.032	.036	.039
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.000	.000	.000	.001	.001	.001	.002
THERMAL (FINAL;KWH/MU)	.000	.000	.000	.000	.000	.000	.000
MINING:							
MOTOR FUEL (FINAL;KWH/MU)	.089	.111	.134	.156	.178	.201	.223
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.003	.003	.003	.003	.003	.003	.003
THERMAL (FINAL;KWH/MU)	.000	.000	.000	.000	.000	.000	.000
MANUF. OF BASIC MATERIALS:							
MOTOR FUEL (FINAL;KWH/MU)	.009	.009	.009	.009	.009	.009	.009
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.136	.144	.149	.152	.155	.156	.156
THERMAL (USEFUL;KWH/MU)	.829	.769	.721	.682	.652	.633	.622
MANUF. OF MACHINERY AND EQUIPMENT:							
MOTOR FUEL (FINAL;KWH/MU)	.003	.003	.003	.003	.003	.003	.003
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.041	.043	.044	.046	.046	.047	.047
THERMAL (USEFUL;KWH/MU)	.088	.082	.077	.073	.070	.067	.066
MANUF. OF CONSUMER GOODS:							
MOTOR FUEL (FINAL;KWH/MU)	.003	.003	.003	.003	.003	.003	.003
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.070	.075	.077	.079	.080	.081	.081
THERMAL (USEFUL;KWH/MU)	.336	.312	.292	.276	.264	.257	.252
MISCELLANEOUS MANUFACTURING:							
MOTOR FUEL (FINAL;KWH/MU)	.003	.003	.003	.003	.003	.003	.003
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.030	.031	.032	.033	.034	.034	.034
THERMAL (USEFUL;KWH/MU)	.005	.005	.005	.004	.004	.004	.004
ALL MANUFACTURING:							
MOTOR FUEL (FINAL;KWH/MU)	.004	.004	.005	.005	.005	.005	.005
ELECTR.,SPECIFIC (FINAL;KWH/MU)	.071	.077	.081	.084	.086	.088	.088
THERMAL (USEFUL;KWH/MU)	.335	.316	.307	.297	.288	.284	.282
THERMAL (FINAL;KWH/MU)	.533	.489	.463	.438	.414	.398	.387

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 7B:
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THERMAL ENERGY DEMAND (USEFUL) BY THE MANUFACTURING SECTOR (MTOE);
PENETRATION OF COMPETING ENERGY SOURCES; AND
EFFICIENCIES (REL. TO CONVENTIONAL USE OF ELECTRICITY):

YEAR:	1993	1998	2003	2008	2013	2018	2023
STEAM GENERATION:	2.647	3.935	5.785	8.485	12.404	18.216	26.796
%FOSSIL	96.5	96.2	95.9	95.5	95.2	94.7	94.0
(EFFICIENCY)	(.648)	(.661)	(.674)	(.686)	(.699)	(.712)	(.725)
%ON-SITE COGENERATION	3.5	3.8	4.1	4.4	4.6	4.8	5.0
(EFFICIENCY)	(.214)	(.260)	(.299)	(.336)	(.370)	(.401)	(.431)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	00.0	.1	.2	.5	1.0
%ELECTRICITY, CONVENTIONAL	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)
FURNACE, DIRECT HEAT:	2.780	4.261	6.675	10.265	15.581	23.743	36.237
%FOSSIL	100.0	99.8	99.0	97.0	94.0	92.0	90.0
(EFFICIENCY)	(.648)	(.661)	(.674)	(.686)	(.699)	(.712)	(.725)
%ELECTRICITY	00.0	.2	1.0	3.0	6.0	8.0	10.0
SPACE AND WATER HEATING:	.237	.362	.549	.830	1.250	1.889	2.855
%FOSSIL	82.3	81.0	79.4	77.8	76.6	75.2	73.4
(EFFICIENCY)	(.648)	(.661)	(.674)	(.686)	(.699)	(.712)	(.725)
%ON-SITE COGENERATION	17.7	19.0	20.5	22.0	23.0	24.0	25.0
(EFFICIENCY)	(.214)	(.260)	(.299)	(.336)	(.370)	(.401)	(.431)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	.1	.2	.4	.8	1.6
%ELECTRICITY, CONVENTIONAL	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 7B (CONT'D):

THERMAL ENERGY DEMAND (USEFUL) BY THE MANUFACTURING SECTOR (MTOE);
PENETRATION OF COMPETING ENERGY SOURCES; AND
EFFICIENCIES (REL. TO CONVENTIONAL USE OF ELECTRICITY):

YEAR:	1993	1998	2003	2008	2013	2018	2023
ALL THERMAL USES IN MANUFACTURING:	5.664	8.558	13.009	19.579	29.235	43.849	65.888
%FOSSIL	97.6	97.3	96.8	95.5	93.7	92.4	90.9
(EFFICIENCY)	(.648)	(.661)	(.674)	(.686)	(.699)	(.712)	(.725)
%ON-SITE COGENERATION	2.4	2.6	2.7	2.8	2.9	3.0	3.1
(EFFICIENCY)	(.214)	(.260)	(.299)	(.336)	(.370)	(.401)	(.431)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	00.0	.1	.1	.2	.5
%ELECTRICITY, CONVENTIONAL	00.0	.1	.5	1.6	3.2	4.3	5.5
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)
ON-SITE COGENERATION:							
HEAT	.135	.218	.350	.556	.858	1.328	2.054
BY-PRODUCT ELECTRICITY	.158	.209	.284	.392	.534	.741	1.037
STEEL PROD. (10**6 TONS):	1.045	1.504	2.289	3.509	5.366	8.225	12.595
OF WHICH ELECTRIC (10**6 TONS):	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
FEEDSTOCK REQU. (10**6 TOE):	.000	.000	.000	.000	.000	.000	.000

SUMMARY OF DETAILED INPUTS INTO MAED/TABLF 8A:
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ACTIVITY LEVELS ASSUMED FOR THE TRANSPORTATION SECTOR:

YEAR:	1993	1998	2003	2008	2013	2018	2023
FREIGHT TRANSPORTATION:							
TOTAL ACTIVITY (10**9 TKM)	52.673	63.710	79.017	100.539	131.626	176.556	241.422
TRUCK	43.293	47.260	56.339	68.467	85.425	108.935	141.232
LOCAL	(6.293)	(6.853)	(8.789)	(11.160)	(14.779)	(19.826)	(26.975)
LONG-DISTANCE	(37.000)	(40.407)	(47.550)	(57.307)	(70.647)	(89.109)	(114.257)
TRAIN	6.180	9.849	14.776	22.018	33.038	49.965	76.048
STEAM	(.003)	(.002)	(.001)	(.000)	(.000)	(.000)	(.000)
DIESEL	(5.993)	(9.552)	(14.110)	(20.587)	(30.065)	(43.969)	(63.880)
ELECTRIC	(.184)	(.295)	(.665)	(1.431)	(2.973)	(5.996)	(12.168)
BARGE	.000	.000	.000	.000	.000	.000	.000
PIPE	3.200	6.600	7.902	10.054	13.163	17.656	24.142
PASSENGER TRANSPORTATION, INTERCITY:							
TOTAL ACTIVITY (10**9 PKM)	154.627	177.262	210.515	256.123	319.080	407.287	532.239
CAR	9.396	14.617	22.537	34.520	52.356	78.857	117.608
BUS	125.605	140.067	160.158	187.698	224.581	274.896	344.974
TRAIN	17.082	18.854	22.557	26.592	32.007	39.412	49.756
STEAM	(.723)	(.377)	(.226)	(.000)	(.000)	(.000)	(.000)
DIESEL	(15.685)	(17.723)	(20.978)	(24.465)	(28.486)	(33.894)	(40.800)
ELECTRIC	(.675)	(.754)	(1.353)	(2.127)	(3.521)	(5.518)	(8.956)
PLANE	2.544	3.725	5.263	7.313	10.135	14.122	19.902
PASSENGER TRANSPORTATION, URBAN:							
TOTAL ACTIVITY (10**9 PKM)	64.681	86.124	112.596	143.289	179.948	220.766	269.132
CAR	22.801	31.780	43.349	57.459	75.038	95.812	121.109
MOTOR FUEL	(22.801)	(31.780)	(43.349)	(57.459)	(75.038)	(95.812)	(121.109)
ELECTRIC	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
MASS TRANSIT	41.880	54.344	69.246	85.830	104.910	124.953	148.022
MOTOR FUEL	(41.880)	(54.344)	(68.554)	(84.114)	(100.713)	(116.207)	(133.220)
ELECTRIC	(.000)	(.000)	(.692)	(1.717)	(4.196)	(8.747)	(14.802)

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 8B:

ACTIVITY LEVELS ASSUMED FOR THE TRANSPORTATION SECTOR:

YEAR:	1993	1998	2003	2008	2013	2018	2023
FREIGHT TRANSPORTATION:							
TOTAL ACTIVITY (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TRUCK	82.2	74.2	71.3	68.1	64.9	61.7	58.5
LOCAL	(14.5)	(14.5)	(15.6)	(16.3)	(17.3)	(18.2)	(19.1)
LONG-DISTANCE	(85.5)	(85.5)	(84.4)	(83.7)	(82.7)	(81.8)	(80.9)
TRAIN	11.7	15.5	18.7	21.9	25.1	28.3	31.5
STEAM	(.1)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
DIESEL	(97.0)	(97.0)	(95.5)	(93.5)	(91.0)	(88.0)	(84.0)
ELECTRIC	(3.0)	(3.0)	(4.5)	(6.5)	(9.0)	(12.0)	(16.0)
BARGE	00.0	00.0	00.0	00.0	00.0	00.0	00.0
PIPE	6.1	10.4	10.0	10.0	10.0	10.0	10.0
PASSENGER TRANSPORTATION, INTERCITY:							
TOTAL ACTIVITY (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
CAR	6.1	8.2	10.7	13.5	16.4	19.4	22.1
BUS	81.2	79.0	76.1	73.3	70.4	67.5	64.8
TRAIN	11.0	10.6	10.7	10.4	10.0	9.7	9.3
STEAM	(4.2)	(2.0)	(1.0)	(00.0)	(00.0)	(00.0)	(00.0)
DIESEL	(91.8)	(94.0)	(93.0)	(92.0)	(89.0)	(86.0)	(82.0)
ELECTRIC	(4.0)	(4.0)	(6.0)	(8.0)	(11.0)	(14.0)	(18.0)
PLANE	1.6	2.1	2.5	2.9	3.2	3.5	3.7
PASSENGER TRANSPORTATION, URBAN:							
TOTAL ACTIVITY (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
CAR	35.3	36.9	38.5	40.1	41.7	43.4	45.0
MOTOR FUEL	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
ELECTRIC	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
MASS TRANSIT	64.7	63.1	61.5	59.9	58.3	56.6	55.0
MOTOR FUEL	(100.0)	(100.0)	(99.0)	(98.0)	(96.0)	(93.0)	(90.0)
ELECTRIC	(00.0)	(00.0)	(1.0)	(2.0)	(4.0)	(7.0)	(10.0)

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 8C:
****

ENERGY INTENSITY (AND LOAD FACTORS) ASSUMED:

YEAR:	1993	1998	2003	2008	2013	2018	2023
FREIGHT TRANSPORTATION (KWH/TKM):							
TRUCK							
LOCAL	1.020	1.003	.986	.969	.951	.935	.919
LONG-DISTANCE	.609	.599	.588	.578	.567	.557	.547
TRAIN							
STEAM	.932	.916	.901	.885	.870	.854	.839
DIESEL	.105	.103	.101	.099	.098	.096	.094
ELECTRIC	.037	.037	.036	.035	.035	.034	.033
BARGE	.000	.000	.000	.000	.000	.000	.000
PIPE	.000	.000	.000	.000	.000	.000	.000
PASSENGER TRANSPORTATION, INTERCITY (KWH/PKM):							
CAR	.322	.322	.321	.321	.322	.322	.322
(P/CAR)	(3.000)	(2.950)	(2.900)	(2.850)	(2.800)	(2.750)	(2.700)
BUS	.080	.080	.080	.080	.080	.080	.081
(P/BUS)	(43.700)	(42.900)	(42.100)	(41.300)	(40.500)	(39.700)	(39.000)
TRAIN							
(P/TRAIN)	(507.000)	(498.000)	(489.000)	(480.000)	(471.000)	(463.000)	(455.000)
STEAM	.750	.750	.751	.752	.753	.752	.752
DIESEL	.084	.084	.084	.084	.085	.085	.084
ELECTRIC	.030	.030	.030	.030	.030	.030	.030
PLANE	1.159	1.140	1.120	1.100	1.082	1.064	1.047
(% OF SEATS OCCUPIED)	(.650)	(.650)	(.650)	(.650)	(.650)	(.650)	(.650)
PASSENGER TRANSPORTATION, URBAN (KWH/PKM):							
CAR							
(P/CAR)	(2.800)	(2.750)	(2.700)	(2.650)	(2.600)	(2.560)	(2.520)
MOTOR FUEL	.411	.411	.411	.412	.412	.412	.411
ELECTRIC	.000	.000	.000	.000	.000	.000	.000
MASS TRANSIT							
MOTOR FUEL	.076	.076	.076	.076	.076	.076	.076
(P/BUS)	(54.849)	(53.920)	(53.000)	(52.080)	(51.170)	(50.260)	(49.360)
ELECTRIC	.000	.000	.060	.061	.063	.064	.065
(P/TRAIN)	(58.400)	(57.400)	(56.400)	(55.400)	(54.400)	(53.400)	(52.500)

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 9A:
****

DWELLINGS AND SERVICE SECTOR BUILDINGS:

YEAR:	1993	1998	2003	2008	2013	2018	2023
PERSONS/HOUSEHOLD	7.190	7.090	6.990	6.891	6.793	6.696	6.600
DWELLINGS (MILLION UNITS)	16.806	19.595	22.696	25.793	28.960	32.200	35.540
OF WHICH IN AREAS REQU. HEATING:	16.806	19.595	22.696	25.793	28.960	32.200	35.540
CONSTRUCTED BEFORE BASE YEAR	16.806	15.966	14.594	12.551	9.714	5.949	1.119
SINGLE FAMILY HOME/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
APARTMENT/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(000)	(.000)
ROOM HEATING	(.354)	(.639)	(1.022)	(1.381)	(1.554)	(1.339)	(.336)
NO HEATING	(16.452)	(15.327)	(13.572)	(11.171)	(8.160)	(4.611)	(.784)
CONSTRUCTED AFTER BASE YEAR	.000	3.629	8.102	13.242	19.246	26.251	34.420
SINGLE FAMILY HOME/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
APARTMENT/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
ROOM HEATING	(.000)	(.363)	(1.257)	(2.800)	(5.201)	(8.704)	(13.605)
NO HEATING	(.000)	(3.266)	(6.844)	(10.442)	(14.045)	(17.547)	(20.815)
DWELLINGS REQUIRING HEATING(%):	100.0	100.0	100.0	100.0	100.0	100.0	100.0
CONSTRUCTED BEFORE BASE YEAR	100.0	81.5	64.3	48.7	33.5	18.5	3.1
SINGLE FAMILY HOME/CENTRAL HEATING	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
APARTMENT/CENTRAL HEATING	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
ROOM HEATING	(2.1)	(4.0)	(7.0)	(11.0)	(16.0)	(22.5)	(30.0)
NO HEATING	(97.9)	(96.0)	(93.0)	(89.0)	(84.0)	(77.5)	(70.0)
CONSTRUCTED AFTER BASE YEAR	00.0	18.5	35.7	51.3	66.5	81.5	96.9
SINGLE FAMILY HOME/CENTRAL HEATING	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
APARTMENT/CENTRAL HEATING	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)	(00.0)
ROOM HEATING	(00.0)	(10.0)	(15.5)	(21.1)	(27.0)	(33.2)	(39.5)
NO HEATING	(100.0)	(90.0)	(84.5)	(78.9)	(73.0)	(66.8)	(60.5)
SERVICE SECTOR WORK FORCE (MILLION WORKERS)	10.492	12.155	14.208	16.504	18.808	21.136	23.455
SERVICE SECTOR BUILDINGS (MILLION SQM)	104.925	130.661	163.386	202.170	244.510	290.614	340.097
OF WHICH IN AREAS REQU. HEATING:	104.925	130.661	163.386	202.170	244.510	290.614	340.097
CONSTRUCTED BEFORE BASE YEAR	104.925	102.302	98.382	91.847	81.738	67.067	46.725
CONSTRUCTED AFTER BASE YEAR	.000	28.359	65.004	110.324	162.771	223.546	293.372
HEATED SERVICE SECTOR BUILDINGS (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0
CONSTRUCTED BEFORE BASE YEAR	100.0	78.3	60.2	45.4	33.4	23.1	13.7
CONSTRUCTED AFTER BASE YEAR	00.0	21.7	39.8	54.6	66.6	76.9	86.3

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 9B:

ENERGY INTENSITY ASSUMED FOR THE HOUSEHOLD SECTOR:

YEAR:	1993	1998	2003	2008	2013	2018	2023
SPACE HEATING:							
CONSTR.BEFORE BASE YEAR (USEFUL;KWH/DW/YR):							
SINGLE FAMILY/CENTRAL HEATING	.000	.000	.000	.000	.000	.000	.000
APARTMENT/CENTRAL HEATING	.000	.000	.000	.000	.000	.000	.000
ROOM HEATING	2170.349	2170.349	2170.349	2170.349	2170.349	2170.349	2170.349
CONSTR.AFTER BASE YEAR (USEFUL;KWH/DW/YR):							
SINGLE FAMILY/CENTRAL HEATING	.000	.000	.000	.000	.000	.000	.000
APARTMENT/CENTRAL HEATING	.000	.000	.000	.000	.000	.000	.000
ROOM HEATING	.000	1800.042	1670.232	1553.023	1435.814	1318.605	1201.395
SIZE OF DWELLINGS CONSTR.AFTER BASE YEAR (SQM):							
SINGLE FAMILY/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
APARTMENT/CENTRAL HEATING	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)	(.000)
ROOM HEATING	(.000)	(35.000)	(35.000)	(35.000)	(35.000)	(35.000)	(35.000)
HEATING DEGREE-DAYS:	(300.000)	(300.000)	(300.000)	(300.000)	(300.000)	(300.000)	(300.000)
WATER HEATING (USEFUL;KWH/DW/YR):	367.476	441.667	534.520	659.585	823.870	1039.343	1320.679
(% OF DWELLINGS WITH HOT WATER)	(31.5)	(33.5)	(35.4)	(37.2)	(38.8)	(40.2)	(41.4)
COOKING (USEFUL;KWH/DW/YR):	2402.486	2465.919	2522.544	2572.100	2614.767	2651.872	2686.973
AIR CONDITIONING (USEFUL;KWH/DW/YR):	5118.736	6331.520	7643.137	9003.400	10348.210	11603.780	12692.890
(% OF DWELLINGS WITH AIR COND.)	(1.0)	(1.4)	(2.0)	(2.8)	(4.0)	(5.8)	(8.5)
SECONDARY ELECTR. APPL. (KWH/DW/YR):	1328.500	1467.366	1619.691	1796.571	2016.343	2290.197	2616.303

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 9C:
****

THERMAL ENERGY DEMAND (USEFUL) BY THE HOUSEHOLD SECTOR (MTOE);
PENETRATION OF COMPETING ENERGY SOURCES; AND
EFFICIENCIES (REL. TO CONVENTIONAL USE OF ELECTRICITY):

YEAR:	1993	1998	2003	2008	2013	2018	2023
SPACE HEATING:	.062	.166	.351	.598	.882	1.171	1.390
%NON-COMMERCIAL	67.6	65.8	62.4	58.8	54.7	50.3	45.6
(EFFICIENCY)	(.130)	(.135)	(.140)	(.145)	(.150)	(.155)	(.160)
%FOSSIL	27.4	28.6	31.3	34.2	37.3	40.7	44.4
(EFFICIENCY)	(.600)	(.610)	(.620)	(.630)	(.640)	(.650)	(.660)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%ELECTRICITY, CONVENTIONAL	5.0	5.6	6.3	7.0	8.0	9.0	10.0
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)
WATER HEATING:	.158	.236	.350	.515	.753	1.095	1.582
%NON-COMMERCIAL	67.6	65.8	62.4	58.8	54.7	50.3	45.6
(EFFICIENCY)	(.130)	(.135)	(.140)	(.145)	(.150)	(.155)	(.160)
%FOSSIL	32.4	34.0	37.3	40.7	44.3	48.1	51.8
(EFFICIENCY)	(.600)	(.610)	(.620)	(.630)	(.640)	(.650)	(.660)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	.1	.2	.3	.4	.5
%ELECTRICITY, CONVENTIONAL	00.0	.1	.2	.4	.7	1.2	2.0
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)
COOKING:	3.286	3.933	4.660	5.400	6.163	6.950	7.773
%NON-COMMERCIAL	67.6	65.8	62.4	58.8	54.7	50.3	45.6
(EFFICIENCY)	(.130)	(.135)	(.140)	(.145)	(.150)	(.155)	(.160)
%FOSSIL	32.4	34.2	37.6	41.2	45.3	49.7	54.4
(EFFICIENCY)	(.592)	(.610)	(.620)	(.630)	(.640)	(.650)	(.660)
%ELECTRICITY	00.0	00.0	00.0	00.0	00.0	00.0	00.0
AIR CONDITIONING:	.073	.144	.281	.533	.985	1.779	3.136
%ELECTRICITY	100.0	100.0	100.0	100.0	100.0	100.0	100.0
(COP)	(2.000)	(2.033)	(2.067)	(2.100)	(2.133)	(2.167)	(2.200)

SUMMARY OF DETAILED INPUTS INTO MAED/TABLE 9D:
****

YEAR:	1993	1998	2003	2008	2013	2018	2023
ENERGY INTENSITY ASSUMED FOR THE SERVICE SECTOR:							
SPACE AND WATER HEATING (USEFUL;KWH/SQM/YR):							
BUILDINGS CONSTR.BEFORE BASE YEAR	73.953	73.953	73.953	73.953	73.953	73.953	73.953
BUILDINGS CONSTR.AFTER BASE YEAR	.000	75.581	75.581	75.581	75.581	75.581	75.581
(% OF FLOOR AREA HEATED)	(50.0)	(52.5)	(55.0)	(57.5)	(60.0)	(62.5)	(65.0)
AIR CONDITIONING:							
SPEC. CONS. (USEFUL;KWH/SQM/YR)	351.977	357.843	363.709	369.576	375.442	381.308	387.174
(% OF FLOOR AREA WITH AIR COND.)	(5.0)	(6.5)	(8.3)	(10.8)	(14.4)	(19.6)	(26.9)
SPECIFIC USE OF ELECTRICITY (KWH/SQM/YR):							
BUILDINGS CONSTR.BEFORE BASE YEAR	33.000	34.000	35.000	36.000	37.000	38.000	39.000
BUILDINGS CONSTR.AFTER BASE YEAR	.000	40.000	41.000	42.000	43.000	44.000	45.000
THERMAL ENERGY DEMAND (USEFUL) BY THE SERVICE SECTOR (MTOE); PENETRATION OF COMPETING ENERGY SOURCES; AND EFFICIENCIES (REL. TO CONVENTIONAL USE OF ELECTRICITY):							
SPACE AND WATER HEATING:	.316	.415	.546	.708	.896	1.112	1.356
%FOSSIL	94.0	93.5	92.8	92.0	91.0	89.8	88.5
(EFFICIENCY)	(.531)	(.550)	(.560)	(.580)	(.590)	(.610)	(.620)
%DISTRICT HEAT	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%SOLAR	00.0	00.0	00.0	00.0	00.0	00.0	00.0
%ELECTRICITY, CONVENTIONAL	6.0	6.5	7.2	8.0	9.0	10.2	11.5
%ELECTRICITY, HEAT PUMP	00.0	00.0	00.0	00.0	00.0	00.0	00.0
(COP)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)	(2.000)
AIR CONDITIONING:	.150	.246	.403	.659	1.078	1.764	2.884
%ELECTRICITY	100.0	100.0	100.0	100.0	100.0	100.0	100.0
(COP)	(2.000)	(2.033)	(2.067)	(2.100)	(2.133)	(2.167)	(2.200)

TOTAL FINAL ENERGY CONSUMPTION (MTOE) MAED/TABLE 10A:

YEAR:	1993	1998	2003	2008	2013	2018	2023
COMMERCIAL ENERGY	20.175	27.479	38.626	54.497	76.902	108.994	155.474
AGRICULTURE	2.208	2.550	2.885	3.189	3.461	3.693	3.922
CONSTRUCTION	.090	.145	.223	.341	.537	.839	1.302
MINING	.055	.117	.228	.406	.710	1.237	2.110
MANFG. (EXCL. COKE, F.STOCKS & BAGASSE)	8.212	12.795	19.956	30.662	46.244	69.731	104.714
TRANSPORTATION (INCL. PIPELINES ELECT.)	5.285	6.246	7.764	9.753	12.474	16.113	21.051
HH/SER (INCLUDING KEROSENE FOR LIGHTING)	4.323	5.626	7.571	10.147	13.475	17.380	22.376
OF WHICH							
KEROSENE FOR LIGHTING	.402	.378	.309	.154	.000	.000	.000
SHARES (%)							
AGRICULTURE	10.946	9.280	7.469	5.851	4.501	3.388	2.523
CONSTRUCTION	.448	.529	.578	.626	.699	.770	.838
MINING	.274	.426	.589	.744	.924	1.135	1.357
MANFG. (EXCL. COKE, F.STOCKS & BAGASSE)	40.706	46.562	51.664	56.263	60.133	63.977	67.351
TRANSPORTATION (INCL. PIPELINES ELECT.)	26.196	22.729	20.099	17.896	16.221	14.784	13.540
HH/SER (INCLUDING KEROSENE FOR LIGHTING)	21.429	20.474	19.601	18.620	17.523	15.946	14.392
GROWTH RATES (% P.A.)							
AGRICULTURE	.000	2.918	2.498	2.022	1.655	1.302	1.213
CONSTRUCTION	.000	9.952	8.969	8.857	9.513	9.328	9.188
MINING	.000	16.197	14.217	12.245	11.856	11.741	11.264
MANFG. (EXCL. COKE, F.STOCKS & BAGASSE)	.000	9.273	9.297	8.970	8.565	8.561	8.471
TRANSPORTATION (INCL. PIPELINES ELECT.)	.000	3.397	4.447	4.667	5.045	5.253	5.491
HH/SER (INCLUDING KEROSENE FOR LIGHTING)	.000	5.409	6.118	6.032	5.838	5.221	5.183
TOTAL	.000	6.375	7.047	7.127	7.131	7.224	7.362
GDP GROWTH RATE (% P.A.)	.000	6.982	6.985	6.989	6.992	6.993	6.994
INCOME ELEASTICITY OF COMM. ENERGY	.000	.913	1.009	1.020	1.020	1.033	1.053
NON-COMMERCIAL ENERGY	20.309	23.776	27.203	30.423	33.358	35.903	37.996
BAGASSE	2.078	2.641	3.291	4.022	4.918	6.012	7.350
NON-COMM. FUELS IN HOUSEHOLDS/SERVICES	18.231	21.135	23.912	26.400	28.440	29.892	30.646
TOTAL (COMMERCIAL & NON-COMMERCIAL)	40.484	51.255	65.829	84.919	110.260	144.897	193.471
NON-ENERGY USES	2.440	3.731	5.109	6.594	8.301	10.452	13.372
COKE	.658	.910	1.329	1.953	2.856	4.177	6.133
NON-ENERGY OIL	.405	.604	.812	1.101	1.506	2.072	2.869
FERTILIZER FEEDSTOCKS	1.377	2.217	2.967	3.541	3.940	4.203	4.370
TOTAL CONSUMPTION (ENERGY & NON-ENERGY)	42.924	54.986	70.938	91.514	118.561	155.349	206.843

FINAL ELECTRICITY CONSUMPTION (MTOE) MAED/TABLE 10B:
****

YEAR:	1993	1998	2003	2008	2013	2018	2023
AGRICULTURE	.459	.512	.548	.588	.626	.652	.675
CONSTRUCTION	.000	.001	.003	.006	.014	.029	.059
MINING	.002	.003	.004	.007	.010	.016	.024
MANUFACTURING	1.050	1.872	3.204	5.449	9.126	14.696	23.251
TRANSPORTATION (INCL. PIPELINES ELECT.)	.012	.023	.032	.049	.080	.133	.213
HOUSEHOLDS/SERVICES	1.448	2.130	3.148	4.678	6.693	8.878	11.854
TOTAL	2.971	4.541	6.939	10.777	16.548	24.403	36.075
SHARES (%)							
AGRICULTURE	15.446	11.272	7.892	5.456	3.785	2.670	1.871
CONSTRUCTION	.013	.025	.040	.058	.082	.117	.164
MINING	.053	.059	.063	.062	.062	.065	.068
MANUFACTURING	35.354	41.234	46.171	50.559	55.146	60.223	64.450
TRANSPORTATION (INCL. PIPELINES ELECT.)	.393	.498	.466	.456	.483	.546	.589
HOUSEHOLDS/SERVICES	48.741	46.912	45.368	43.409	40.442	36.379	32.858
GROWTH RATES (% P.A.)							
AGRICULTURE	.000	2.209	1.362	1.431	1.273	.794	.704
CONSTRUCTION	.000	23.953	19.810	17.734	16.613	16.110	15.559
MINING	.000	11.252	10.211	8.897	8.953	9.175	8.972
MANUFACTURING	.000	12.257	11.342	11.205	10.865	9.999	9.609
TRANSPORTATION (INCL. PIPELINES ELECT.)	.000	14.136	7.414	8.740	10.247	10.730	9.799
HOUSEHOLDS/SERVICES	.000	8.026	8.126	8.245	7.424	5.814	5.953
TOTAL	.000	8.855	8.852	9.204	8.956	8.078	8.132
GDP GROWTH RATE (% P.A.)	.000	6.982	6.985	6.989	6.992	6.993	6.994
INCOME ELEASTICITY OF ELECTRICITY	.000	1.268	1.267	1.317	1.281	1.155	1.163
TOTAL TRANSPORTATION	.012	.023	.032	.049	.080	.133	.213
OF WHICH							
ELECTRICITY FOR PIPELINES	.009	.020	.024	.031	.042	.058	.080

APPENDIX D

LOAD MODULATION COEFFICIENTS AND OUTPUT OF MODULE 2 AND MODULE 3 OF MAED FOR THE REFERENCE CASE

Table D 1. Seasonal Load Coefficients

Week	Industry, Agriculture and Transport sector	Household and Service Sector
1	1 050	1 151
2	1 050	1 151
3	1 050	1 151
4	1 050	1 151
5	1 072	1 155
6	1 089	1 159
7	1 089	1 159
8	1 089	1 159
9	1 071	1 147
10	0 962	1 075
11	0 962	1 075
12	0 962	1 075
13	0 962	1 075
14	0 930	0 968
15	0 925	0 951
16	0 925	0 951
17	0 925	0 951
18	0 929	0 901
19	0 933	0 835
20	0 933	0 835
21	0 933	0 835
22	0 940	0 837
23	0 985	0 845
24	0 985	0 845
25	0 985	0 845
26	0 985	0 845
27	0 999	0 891
28	1 005	0 910
29	1 005	0 910
30	1 005	0 910
31	1 002	0 916
32	0 997	0 931
33	0 997	0 931
34	0 997	0 931
35	0 983	0 911
36	0 948	0 860
37	0 948	0 860
38	0 948	0 860
39	0 948	0 860
40	0 994	0 942
41	1 001	0 956
42	1 001	0 956
43	1 001	0 956
44	1 033	1 044
45	1 057	1 110
46	1 057	1 110
47	1 057	1 110
48	1 055	1 126
49	1 049	1 220
50	1 049	1 220
51	1 049	1 220
52	1 049	1 220

Table D 2. Daily Weight Coefficients

Week	Industry, Agriculture and Transport Sector		Household and Service Sector	
	Working day	Non-Working day	Working day	Non-Working day
1	1	0 775	1	1 01
2	1	0 775	1	1 01
3	1	0 775	1	1 01
4	1	0 775	1	1 01
5	1	0 775	1	0 99
6	1	0 775	1	0 99
7	1	0 775	1	0 99
8	1	0 775	1	0 99
9	1	0 775	1	0 98
10	1	0 775	1	0 98
11	1	0 775	1	0 98
12	1	0 775	1	0 98
13	1	0 775	1	0 98
14	1	0 775	1	0 97
15	1	0 775	1	0 97
16	1	0 775	1	0 97
17	1	0 775	1	0 97
18	1	0 775	1	0 97
19	1	0 775	1	0 97
20	1	0 775	1	0 97
21	1	0 775	1	0 97
22	1	0 775	1	0 98
23	1	0 775	1	0 98
24	1	0 775	1	0 98
25	1	0 775	1	0 98
26	1	0 775	1	0 98
27	1	0 775	1	0 99
28	1	0 775	1	0 99
29	1	0 775	1	0 99
30	1	0 775	1	0 99
31	1	0 775	1	1
32	1	0 775	1	1
33	1	0 775	1	1
34	1	0 775	1	1
35	1	0 775	1	1
36	1	0 775	1	1
37	1	0 775	1	1
38	1	0 775	1	1
39	1	0 775	1	1
40	1	0 775	1	1
41	1	0 775	1	1
42	1	0 775	1	1
43	1	0 775	1	1
44	1	0 775	1	1
45	1	0 775	1	1
46	1	0 775	1	1
47	1	0 775	1	1
48	1	0 775	1	1 01
49	1	0 775	1	1 01
50	1	0 775	1	1 01
51	1	0 775	1	1 01
52	1	0 775	1	1 01

Table D 3a. Hourly Load Coefficient - by Client

(Industry, Agriculture and Transport Sector)

Hour	Summer Period				Winter Period			
	Agriculture	Transport	Small industry	Large Industry	Agriculture	Transport	Small industry	Large Industry
1	0.398	1	0.661	0.828	0.596	1	0.661	0.828
2	0.859	1	0.661	0.825	0.902	1	0.661	0.825
3	0.955	1	0.651	0.816	0.962	1	0.651	0.816
4	0.975	1	0.661	0.810	0.982	1	0.661	0.810
5	1.053	1	0.671	0.839	1.043	1	0.671	0.839
6	1.652	1	0.682	0.870	1.421	1	0.682	0.870
7	1.712	1	0.967	1.004	1.449	1	0.967	1.004
8	1.754	1	0.895	1.076	1.494	1	0.895	1.076
9	1.927	1	1.780	1.161	1.650	1	1.780	1.161
10	1.913	1	1.323	1.188	1.630	1	1.323	1.188
11	1.307	1	1.323	1.202	1.196	1	1.323	1.202
12	0.701	1	1.496	1.233	0.809	1	1.496	1.233
13	0.712	1	1.628	1.259	0.812	1	1.628	1.259
14	0.745	1	1.323	1.249	0.834	1	1.323	1.249
15	1.554	1	1.526	1.233	1.375	1	1.526	1.233
16	1.589	1	1.221	1.134	1.397	1	1.221	1.134
17	1.048	1	0.997	0.996	1.020	1	0.997	0.996
18	0.563	1	0.895	0.977	0.702	1	0.895	0.977
19	0.485	1	0.916	0.957	0.653	1	0.916	0.957
20	0.420	1	0.743	0.902	0.617	1	0.743	0.902
21	0.419	1	0.753	0.876	0.617	1	0.753	0.876
22	0.419	1	0.753	0.864	0.615	1	0.753	0.864
23	0.420	1	0.743	0.856	0.612	1	0.743	0.856
24	0.420	1	0.731	0.845	0.612	1	0.731	0.845

Table D 3b. Hourly Load Coefficient - by Client

(Household and Service Sector)

Hour	Summer Period					Winter Period				
	Commercial	Residential Air conditioners	Residential cooling	Residential Lighting	Residential Other Appliances	Commercial	Residential Air conditioners	Residential cooling	Residential Lighting	Residential Other Appliances
1	0.527	1.653	1.005	1.799	0.502	0.494	0	0	1.602	0.502
2	0.663	1.571	0.876	1.763	0.430	0.436	0	0	1.530	0.430
3	0.483	1.453	0.876	1.57	0.430	0.436	0	0	1.499	0.430
4	0.534	1.435	0.876	1.641	0.574	0.450	0	0	1.335	0.574
5	0.669	1.380	0.876	1.979	0.430	0.450	0	0	1.397	0.43
6	0.639	1.180	0.876	1.159	0.861	0.523	0	0	1.684	0.861
7	0.629	0.817	1.005	1.377	1.004	0.653	0	0	0.986	1.004
8	0.636	0.645	0.967	0	1.148	0.653	0	0	1.171	1.148
9	0.881	0.509	0.992	0	1.471	1.118	0	0	0	1.471
10	0.798	0.291	0.992	0	1.363	1.132	0	0	0	1.363
11	0.845	0.254	0.967	0	1.399	1.132	0	0	0	1.399
12	0.994	0.381	1.005	0	1.076	1.336	0	0	0	1.076
13	1.245	0.499	1.044	0	1.004	1.321	0	0	0	1.004
14	1.130	0.917	1.083	0	1.220	1.525	0	0	0	1.220
15	1.004	1.308	1.083	0	1.076	1.103	0	0	0	1.076
16	1.225	1.271	1.083	0	1.256	1.074	0	0	0	1.256
17	1.335	1.017	1.083	0	1.758	1.045	0	0	0	1.758
18	1.214	0.89	1.044	0	1.435	1.118	0	0	0.411	1.435
19	1.614	0.844	1.005	0.483	1.507	1.815	0	0	1.191	1.507
20	1.906	0.726	1.005	1.401	1.435	1.917	0	0	2.054	1.435
21	2.048	0.908	1.044	2.415	0.933	1.931	0	0	2.711	0.933
22	1.354	0.944	1.121	3.188	0.861	0.871	0	0	2.300	0.861
23	0.905	1.417	1.044	2.705	0.574	0.857	0	0	2.143	0.574
24	0.722	1.690	1.048	2.520	0.253	0.610	0	0	1.986	0.253

Table D.4. Selected Parts of Output of Module 2

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ELECTRIC POWER DEMAND ON AN HOUR-BY-HOUR BASIS FOR
PLANNING TARGET GROWTH SCENARIO--FOR PAKISTAN

SUMMARY OF GENERAL INPUT DATA FOR THE RUN
*****************************************
NUMBER OF SECTOR(S) CONSIDERED:        2
NUMBER OF YEAR(S) CONSIDERED:          7
PRINTED OUTPUT OPTION SELECTED:        0
(.EQ. 0  MINIMUM OUTPUT)
(.NE. 0  MAXIMUM OUTPUT)

INPUT DATA FOR THE YEAR:        1993
***********************
FIRST DAY OF THE YEAR IS:       3
(MONDAY=1, TUESDAY=2,..)

SUMMER  PERIOD  STARTS:   415   ENDS:  1014
SPECIAL PERIOD  STARTS:   625   ENDS:   625

INDUSTRIAL SECTOR (INCLUDING TRANSPORTATION)

INPUT DATA FOR THE YEAR:        1993
***********************

ELECTRICITY DEMAND        24992.400  GWH
AVERAGE GROWTH RATE           6.720   %

ENERGY-GROWTH TREND COEFFICIENTS  T(I):
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```

.9692	.9704	.9716	.9729	.9741	.9753	.9765	.9777	.9790	.9802	.9814	.9826	.9839
.9851	.9863	.9876	.9888	.9900	.9913	.9925	.9938	.9950	.9963	.9975	.9988	1.0000
1.0013	1.0025	1.0038	1.0050	1.0063	1.0075	1.0088	1.0101	1.0113	1.0126	1.0139	1.0151	1.0164
1.0177	1.0189	1.0202	1.0215	1.0228	1.0240	1.0253	1.0266	1.0279	1.0292	1.0305	1.0318	1.0331

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ERROR SUMMATION OF K ARRAY GIVES VALUE OF      .0050
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WEIGHTED LOAD COEFFICIENTS FOR EACH DAY TYPE

SUMMER VALUES

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 0

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 1

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 2

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 3

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 4

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 5

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 6

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 7

.6840	.8206	.8430	.8465	.8880	1.0871	1.2127	1.2605	1.4511	1.4171	1.2436	1.0974
1.1292	1.1027	1.3563	1.2779	1.0117	.8448	.8117	.7425	.7278	.7208	.7153	.7077

WINTER VALUES

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 0

.7434	.8335	.8451	.8486	.8850	1.0178	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7796	.7729	.7653

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 1

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 2

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 3

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 4

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 5

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 6

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 7

.7434	.8335	.8451	.8486	.8850	1.0187	1.1338	1.1825	1.3680	1.3322	1.2103	1.1298
1.1592	1.1294	1.3026	1.2203	1.0033	.8865	.8621	.8016	.7872	.7793	.7726	.7650

TOTAL NUMBER OF WORKING DAYS 354.076

ANNUAL ELECTRICITY DEMAND = 24992.379 GWH ANNUAL GROWTH RATE = 6.720 %

ERROR SUMMATION IN ANNUAL DEMAND = .0212 GWH FOR SECTOR : 1

ANNUAL DEMAND GIVEN AS INPUT DATA= 24992.4000 GWH
CALCULATED FROM THE COEFFICIENTS = 24992.3788 GWH

HOUSEHOLD AND SERVICE SECTOR

INPUT DATA FOR THE YEAR: 1993
****

ELECTRICITY DEMAND 23764.900 GWH
AVERAGE GROWTH RATE 9.960 %

ENERGY-GROWTH TREND COEFFICIENTS T(I):

.9554	.9571	.9589	.9606	.9624	.9641	.9659	.9677	.9694	.9712	.9730	.9748	.9765
.9783	.9801	.9819	.9837	.9855	.9873	.9891	.9909	.9927	.9945	.9964	.9982	1.0000
1.0018	1.0037	1.0055	1.0073	1.0092	1.0110	1.0129	1.0147	1.0166	1.0184	1.0203	1.0222	1.0240
1.0259	1.0278	1.0296	1.0315	1.0334	1.0353	1.0372	1.0391	1.0410	1.0429	1.0448	1.0467	1.0486

ERROR SUMMATION OF K ARRAY GIVES VALUE OF .0020

WEIGHTED LOAD COEFFICIENTS FOR EACH DAY TYPE

SUMMER VALUES

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 0

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 1

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 2

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 3

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 4

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 5

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

TOTAL NUMBER OF WORKING DAYS 365.653

ANNUAL ELECTRICITY DEMAND = 23764.894 GWH ANNUAL GROWTH RATE = 9.960 %
ERROR SUMMATION IN ANNUAL DEMAND = .0058 GWH FOR SECTOR : 2

ANNUAL DEMAND GIVEN AS INPUT DATA= 23764.9000 GWH
CALCULATED FROM THE COEFFICIENTS = 23764.8942 GWH

TOTAL RESULTS FOR THE POWER GENERATING SYSTEM
****

TOTAL ELECTRICITY CONSUMPTION = 48757.273 GWH
ANNUAL AVERAGE GROWTH RATE = 8.299 %

Table D.5 : Selected Parts of Output of Module 3

LOAD DURATION CURVE IN PER UNIT SYSTEM FOR
PLANNING TARGET GROWTH SCENARIO--FOR PAKISTAN

SUMMARY OF GENERAL INPUT DATA FOR THE RUN
****

TOTAL NUMBER OF YEARS CONSIDERED	7
PRINTOUT OPTION SELECTED (.EQ. 0 MINIMUM OUTPUT) (.NE. 0 MAXIMUM OUTPUT)	0
NUMBER OF PERIODS PER YEAR	6
NUMBER OF MONTHS PER PERIOD	2
INTERVAL BETWEEN POINTS OF L.D.C.	.010

PLANNING TARGET GROWTH SCENARIO--FOR PAKISTAN

SUMMARY OF RESULTS FOR THE YEAR: 1993
****

ANNUAL MAXIMUM LOAD (MW)	7581.90
ANNUAL ENERGY (GWH)	48757.31
ANNUAL LOAD FACTOR (%)	73.41
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD: ABSOLUTE (MW)	7121.3	6816.3	6799.2	7076.4	7308.4	7581.9
REL. TO ANNUAL PEAK	.939	.899	.897	.933	.964	1.000
ENERGY (GWH)	8869.2	7738.5	7338.8	7593.1	7876.6	9341.2
LOAD FACTOR (%)	83.70	77.55	73.73	75.78	73.62	84.16
NUMBER OF HOURS	1488	1464	1464	1416	1464	1464

SUMMARY OF RESULTS FOR THE YEAR: 1998
****

ANNUAL MAXIMUM LOAD (MW)	10718.20
ANNUAL ENERGY (GWH)	68870.95
ANNUAL LOAD FACTOR (%)	73.35
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD: ABSOLUTE (MW)	10055.3	9656.1	9640.8	9993.7	10283.7	
10718.2						
REL. TO ANNUAL PEAK	.938	.901	.899	.932	.959	
1.000						
ENERGY (GWH)	12553.0	10908.7	10389.3	10735.5	11132.3	
13152.2						
LOAD FACTOR (%)	83.90	77.17	73.61	75.86	73.94	
83.82						
NUMBER OF HOURS	1488	1464	1464	1416	1464	
1464						

ERROR SUMMATION IN ANNUAL DEMAND = .0547 GWH

ANNUAL ENERGY GIVEN AS INPUT DATA = 68871.0 GWH
CALCULATED FROM THE L.D.C. POINTS = 68870.9 GWH

SUMMARY OF RESULTS FOR THE YEAR: 2003
****

ANNUAL MAXIMUM LOAD (MW)	16026.20
ANNUAL ENERGY (GWH)	103330.10
ANNUAL LOAD FACTOR (%)	73.60
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD:						
ABSOLUTE (MW)	14818.8	14241.3	14300.2	14833.0	15285.3	16026.2
REL. TO ANNUAL PEAK	.925	.889	.892	.926	.954	1.000
ENERGY (GWH)	18738.5	16330.3	15634.4	16118.6	16770.2	19738.1
LOAD FACTOR (%)	84.98	78.33	74.68	76.74	74.94	84.13
NUMBER OF HOURS	1488	1464	1464	1416	1464	1464

ERROR SUMMATION IN ANNUAL DEMAND = .0547 GWH

ANNUAL ENERGY GIVEN AS INPUT DATA = 103330.0 GWH
CALCULATED FROM THE L.D.C. POINTS = 103330.1 GWH

SUMMARY OF RESULTS FOR THE YEAR: 2008
****

ANNUAL MAXIMUM LOAD (MW)	24193.90
ANNUAL ENERGY (GWH)	157621.20
ANNUAL LOAD FACTOR (%)	74.17
TOTAL NUMBER OF HOURS	8784

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD:						
ABSOLUTE (MW)	22581.1	21326.5	21535.2	22310.1	22982.8	24193.9
REL. TO ANNUAL PEAK	.933	.881	.890	.922	.950	1.000
ENERGY (GWH)	28454.1	24889.1	23705.3	24995.5	25568.7	
30008.6						
LOAD FACTOR (%)	84.68	79.72	75.19	77.80	75.99	84.72
NUMBER OF HOURS	1488	1464	1464	1440	1464	1464

ERROR SUMMATION IN ANNUAL DEMAND = .0313 GWH

ANNUAL ENERGY GIVEN AS INPUT DATA = 157621.2 GWH
CALCULATED FROM THE L.D.C. POINTS = 157621.2 GWH

SUMMARY OF RESULTS FOR THE YEAR: 2013
****

ANNUAL MAXIMUM LOAD (MW)	37501.60
ANNUAL ENERGY (GWH)	242031.80
ANNUAL LOAD FACTOR (%)	73.67
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD:						
ABSOLUTE (MW)	35081.3	32139.1	32619.7	33740.1	34788.5	37501.6
REL. TO ANNUAL PEAK	.935	.857	.870	.900	.928	1.000
ENERGY (GWH)	43708.2	38265.3	36660.2	37937.6	39514.7	45945.7
LOAD FACTOR (%)	83.73	81.33	76.77	79.41	77.59	83.69
NUMBER OF HOURS	1488	1464	1464	1416	1464	1464

SUMMARY OF RESULTS FOR THE YEAR: 2018
****

ANNUAL MAXIMUM LOAD (MW)	55925.40
ANNUAL ENERGY (GWH)	356915.70
ANNUAL LOAD FACTOR (%)	72.85
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD: ABSOLUTE (MW)	52783.5	52089.8	47085.1	48537.0	52152.7	55925.4
REL. TO ANNUAL PEAK	.944	.931	.842	.868	.933	1.000
ENERGY (GWH)	64456.1	56737.5	54203.7	56250.6	58097.9	67169.8
LOAD FACTOR (%)	82.07	74.40	78.63	81.84	76.09	82.04
NUMBER OF HOURS	1488	1464	1464	1416	1464	1464

ERROR SUMMATION IN ANNUAL DEMAND = .0313 GWH

ANNUAL ENERGY GIVEN AS INPUT DATA = 356915.7 GWH
CALCULATED FROM THE L.D.C. POINTS = 356915.7 GWH

SUMMARY OF RESULTS FOR THE YEAR: 2023
****

ANNUAL MAXIMUM LOAD (MW)	83551.91
ANNUAL ENERGY (GWH)	527628.30
ANNUAL LOAD FACTOR (%)	72.09
TOTAL NUMBER OF HOURS	8760

PERIOD NO.:	1	2	3	4	5	6
MAXIMUM LOAD: ABSOLUTE (MW)	79044.3	71336.6	70898.2	71532.2	80946.7	83551.9
REL. TO ANNUAL PEAK	.946	.854	.849	.856	.969	1.000
ENERGY (GWH)	94587.1	82529.6	80942.7	83313.8	86866.6	99388.5
LOAD FACTOR (%)	80.42	79.02	77.98	82.25	73.30	81.25
NUMBER OF HOURS	1488	1464	1464	1416	1464	1464

ERROR SUMMATION IN ANNUAL DEMAND = .0625 GWH

ANNUAL ENERGY GIVEN AS INPUT DATA = 527628.4 GWH
CALCULATED FROM THE L.D.C. POINTS = 527628.3 GWH

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APPENDIX E

PROJECTION OF INDIGENOUS OIL AND GAS PRODUCTION LEVELS

Several studies have indicated that the oil and gas resource potential of Pakistan is very promising and lies in the range of 33–404 billion barrels for oil and 140–1443 trillion cubic feet for gas [8, 14]. Although the first oil and gas exploration well (Kundal) in areas constituting Pakistan was drilled as far back as 1868 the drilling density (i.e. number of exploratory wells per 1000 sq.km sedimentary area) in Pakistan is still very low compared to many other regions of the World. The drilling density in some countries lies in the range of 10–100 compared to only 0.4 in Pakistan in the base year.

In view of the limited petroleum drilling data for most of the sedimentary basins of the country one method for projecting oil and gas production levels is to divide the country into several geological/sedimentary zones, with each zone differing from others in terms of some characteristics important for producing oil and gas, and then seeking judgment of experts about these characteristics. There are other methods for projecting oil and gas production profiles [115] e.g.: (i) those based on statistical analysis for relatively well explored regions, and (ii) those in which subjective estimates of the values of various geological parameters are used to formulate expectation curves of recoverable resources of oil and gas for various sedimentary basins. In one application of this method [116] the domestic production of oil was projected to reach a level of 6.0 million TOE in 2002–03 (as compared to 0.5 million TOE in 1980–81) and domestic production of gas was projected to reach 20.0 million TOE in 2002–03 (as compared to 6.6 million TOE in 1980–81) for a Policy Case of exploration and development envisaging drilling of 97 exploration wells and at least 120 development wells during 1983–88 and continuation of this activity level during subsequent plan periods.

A methodology was developed by Applied Systems Analysis Group (ASAG) of Pakistan Atomic Energy Commission and Hydrocarbon Development Institute of Pakistan (HDIP) in 1984 to project: (i) the number of discoveries of oil and gas, (ii) addition to proven reserves of oil and gas, (iii) the number of development wells of oil and gas, (iv) the production levels of oil and gas and (v) the investments required for petroleum exploration and development. A computer programme in FORTRAN language was written by ASAG to translate the methodology into a model. The model can consider several geological zones and time periods with each time period corresponding to a Five Year Plan. The model was used to carry out the "Study on Investment Requirements for Petroleum Exploration and Development in Pakistan, up to the year 2000", [117]. Experts from HDIP, Oil and Gas Development Corporation (OGDC) and Directorate General of Petroleum Concessions (DGPC) provided estimates for the model parameters for each of the eight geological zones considered in the study.

During 1994, with the coordination of the Energy Wing of the Planning Commission, experts from HDIP, OGDC and DGPC provided estimates for the values of the various model parameters for 12 geological zones and also developed some scenarios for the exploration effort in these zones for the Eighth Five Year Plan (1993–1998) to 11th Five Year Plan (2008–2013). These estimates for the values of various model parameters are given in Table E.1. In the light of Energy Wing's scenarios for exploration in each zone ASAG has developed a "Base Case" scenario extending up to 13th Five Year Plan (2018–2023). This scenario assumes that exploration drilling effort in Pakistan will increase from a target of 142 wells during 8th Five

Year Plan to 285 wells during the 13th Five Year Plan (2018–2023). Table E.2 gives distribution of exploratory wells in different regions for the "Base Case" scenario of exploratory effort while Table E.3 gives the aggregate results of the model for Pakistan.

Table E.1. Assumptions for Long-term Discoveries and Projection of Oil & Gas

	GEOLOGICAL REGIONS											
	INDUS BASIN							BALUCHISTAN BASIN				PASHIN BASIN
	NORTH		CENTER		SOUTH			WEST				
MAIN PARAMETERS	POTWAR	KOHAT/ BANNU	PUNJAB PLATFORM	SULEMAN FOLD BELT AND ADJACENT TROUGHS	EAST SINDH PLATEFORM	WEST SINDH PLATFORM	KIRTHAR FOLD BELT AND ADJACENT TROUGHS	INDUS OFFSHORE	MAKRAN/ TURBAT COASTAL	PANJGUR/ KHARAN/ DALBANDIN	MAKRAN OFFSHORE	
	1	2	3	4	5	6	7	8	9	10	11	12
1 SUCCESS RATE (DISCOVERIES EXPL WELLS)	1 5	1 7	1 6	1 5	1 7	1 4	1 6	1 7	1 7	1 7	1 7	1 7
2 CHANCE OF A DISCOVERY TO BE OF OIL (%)	90	90	30	30	50	50	50	30	40	50	40	30
3 AVERAGE SIZE OF DISCOVERY												
OIL(MILLION BBL)	25	25	5	5	5	5	5	50	5	5	50	5
GAS(TCF)	0 1	0 1	1	1	0 1	0 1	0 1	2	0 5	0 5	2	0 5
4 AVERAGE LIFE OF A FIELD (YEARS)												
OIL	15	15	15	15	8	8	8	15	15	15	20	15
GAS	15	15	15	15	8	8	8	15	15	15	20	15
5 LEAD TIME (YEARS FROM DISCOVERY TO PRODUCTION												
OIL	1	1	3	3	1	1	1	3	3	3	3	3
GAS	3	3	5	5	2	2	2	5	5	5	5	5
6 COST OF AN EXPL WELL MILLION Rs)	300	300	195	195	66	66	66	630	195	195	630	195
COST OF DEV WELL (MILLION s)	240	240	162	162	45	45	45	540	162	162	540	162
7 ULTIMATE RECOVERABLE RESOURCE POTENTIAL												
OIL(MILLION BBL)	1848	1512	1440	5760	1896	3792	3792	4163	3330	7515	4163	400
GAS(TCF)	8	7	13	30	7	15	15	25	26	39	25	2 4
8 DEVELOPMENT WELLS REQUIRED FOR OPTIMUM PRODUCTION												
OIL	8	8	8	8	4	4	4	10	10	10	10	10
GAS	8	8	20	20	4	4	4	10	6	6	10	10
9 SUCCESS RATIO FOR DEVELOPMENT WELLS	0 9	0 9	0 9	0 9	0 9	1	0 9	1	0 9	0 9	1	1

Table E.2. Distribution of Exploratory Wells in Different Regions

Zone	1993–1998	1998–2003	2003–2008	2008–2013	2013–2018	2018–2023	Total
North-Potwar	23	27	32	35	40	42	199
North-Kohat/ Bannu	10	18	26	26	36	50	166
Centre-Punjab Platform	15	12	10	8	6	4	55
Centre-Suleman Fold Belt	16	14	12	10	8	6	66
South-East Sindh Platform	2	10	16	22	26	28	104
South-West Sindh Platform	59	49	43	40	38	40	269
South-Kirthar Fold Belt	9	15	20	26	29	31	130
South-Indus Offshore	1	2	4	7	10	12	36
West-Makran/ Turbat Coastal	2	9	12	18	21	22	84
West-Panjgur/ Kharan/Dalbandin	3	10	14	23	26	28	104
West-Makran Offshore	1	2	4	8	10	12	37
West-Pashin Basin	1	2	4	7	9	10	33
Total	142	170	197	230	259	285	1283

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 6

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 7

.9715	.9365	.8519	.9042	.9713	.8822	.9777	.7253	.8486	.7994	.8076	.7999
.8645	.9079	.8659	.9517	1.0633	.9546	1.1409	1.3670	1.5189	1.5132	1.2519	1.1241

WINTER VALUES

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 0

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 1

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 2

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 3

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 4

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 5

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 6

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

HOURLY LOAD CURVE COEFFICIENTS FOR TYPE OF DAY 7

.8846	.8168	.8059	.8031	.7745	1.0476	.8924	1.0076	.8503	.8167	.8292	.7774
.7477	.8845	.7075	.7618	.9288	.9815	1.4888	1.7962	1.8547	1.3677	1.2081	.9667

Table E.3. Aggregate Results for the Country

		Discoveries of		Development Wells		Addition to Proven Reserves (Million TOE)		Maximum Productin and Reserves Position (Million TOE)				Investment (Billion US $ of 1992-93)			
								Oil		Gas		Exploration	Development		
Period	Exploratory Drilling	Oil	Gas	Oil	Gas	OIL	GAS	Annual Production	Remaining Reserves	Annual Production	Remaining Reserves		Oil	Gas	Total
1993–98	142	17	12	105	77	27 50	107 02	4 21	33 76	13 49	446 53	0 89	0 65	0 33	1 87
1998–03	170	19	14	131	125	31 53	109 25	5 22	39 18	20 95	451 04	1 16	0 86	0 65	2 67
2003–08	197	17	18	120	144	32 87	211 82	5 29	45 58	29 38	515 98	1 46	0 81	0 95	3 22
2008–13	230	26	15	189	139	56 35	120 40	6 93	67 30	38 17	445 51	1 79	1 52	0 85	4 16
2013–18	259	29	17	221	128	57 69	178 37	8 84	80 77	42 19	412 96	2 13	1 68	0 84	4 64
2018–23	285	29	19	228	128	65 74	191 75	10 70	93 01	44 53	382 05	2 42	1 80	0 93	5 15
Total						271 67	918 63					9 84	7 32	4 55	21 71
Total URR						5314 06	4730 35								
Percentage of URR						5 11	19 42								

Appendix F

OUTPUT OF REPROBAT MODULE

SUMMARY REPORT
ON A GENERATION EXPANSION PLAN FOR
PAKISTAN CASE STUDY BY ASAG
PROCESSED BY THE WASP-III COMPUTER PROGRAM PACKAGE
OF THE IAEA

STUDY PERIOD

1993 - 2022

PLANNING PERIOD

1993 - 2022

CONSTRUCTION COSTS
IN MILLION $
ARE REPORTED ONLY FOR
PLANTS COMMISSIONED
DURING THE PLANNING PERIOD.
ALL OTHER INFORMATION IS GIVEN
FOR THE WHOLE STUDY PERIOD.

DATE OF REPORT: APRIL 7, 1996

STUDY CARRIED OUT BY
APPLIED SYSTEMS ANALYSIS GROUP
PAKISTAN ATOMIC ENERGY COMMISSION,
ISLAMABAD, PAKSTAN

REFERENCE CASE OPTIMAL SOLUTION

THIS IS A LIST OF THE DIFFERENT TYPES OF ELECTRIC POWER PLANTS
USED IN THE STUDY.
THE NUMERIC CODES ARE USED BY THE COMPUTER PROGRAMS

0	DCOL	DOMESTIC COAL PLANTS
1	ICOL	IMPORTED COAL PLANTS
2	DGAS	DOMESTIC GAS PLANTS
3	IGAS	IMPORTED GAS PLANTS
4	HSFO	HSFO FIRED PLANTS
5	LSFO	LSFO FIRED PLANTS
6	HSD	HSD FIRED PLANTS
7	NUCL	NUCLEAR PLANTS
8	****	NOT APPLICABLE
9	****	NOT APPLICABLE
	HYD1	HYDRO TYPE 1
	HYD2	HYDRO TYPE 2

ANNUAL LOAD DESCRIPTION
PERIOD(S) PER YEAR : 6

YEAR	PEAKLOAD MW	GR.RATE %	MIN.LOAD MW	GR.RATE %	ENERGY GWH	GR.RATE %	LOADFACTOR %
1993	7581.9	-	3467.7	-	48732.6	-	73.37
1994	8125.4	7.2	3716.3	7.2	52226.0	7.2	73.37
1995	8707.9	7.2	3982.7	7.2	55970.0	7.2	73.37
1996	9332.2	7.2	4268.2	7.2	59982.7	7.2	73.37
1997	10001.2	7.2	4574.2	7.2	64282.7	7.2	73.37
1998	10718.2	7.2	5013.3	9.6	68841.7	7.1	73.32
1999	11616.2	8.4	5433.4	8.4	74609.4	8.4	73.32
2000	12589.4	8.4	5888.6	8.4	80860.1	8.4	73.32
2001	13644.2	8.4	6381.9	8.4	87635.0	8.4	73.32
2002	14787.3	8.4	6916.6	8.4	94977.0	8.4	73.32
2003	16026.2	8.4	7436.1	7.5	103276.1	8.7	73.56
2004	17402.3	8.6	8074.6	8.6	112143.9	8.6	73.56
2005	18896.5	8.6	8767.9	8.6	121772.8	8.6	73.56
2006	20519.0	8.6	9520.7	8.6	132228.6	8.6	73.56
2007	22280.8	8.6	10338.2	8.6	143582.0	8.6	73.56
2008	24193.9	8.6	11198.2	8.3	157156.1	9.5	74.15
2009	26410.4	9.2	12224.1	9.2	171553.8	9.2	74.15
2010	28829.9	9.2	13344.0	9.2	187270.1	9.2	74.15
2011	31471.1	9.2	14566.5	9.2	204426.5	9.2	74.15
2012	34354.3	9.2	15901.0	9.2	223154.9	9.2	74.15
2013	37501.6	9.2	16961.8	6.7	241985.8	8.4	73.66
2014	40622.0	8.3	18373.2	8.3	262120.7	8.3	73.66
2015	44002.1	8.3	19902.0	8.3	283931.4	8.3	73.66
2016	47663.4	8.3	21558.0	8.3	307556.6	8.3	73.66
2017	51629.4	8.3	23351.8	8.3	333147.9	8.3	73.66
2018	55925.4	8.3	24954.3	6.9	356768.9	7.1	72.82
2019	60600.8	8.4	27040.5	8.4	386595.1	8.4	72.82
2020	65667.1	8.4	29301.1	8.4	418914.9	8.4	72.82
2021	71157.0	8.4	31750.8	8.4	453937.0	8.4	72.82
2022	77105.8	8.4	34405.1	8.4	491886.6	8.4	72.82

FIXED SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS IN YEAR 1993

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPACITY MW	HEAT RATES KCAL/KWH BASE LOAD	HEAT RATES KCAL/KWH AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FUEL COSTS CENTS/ MILLION KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
3	MULT	4	15.	59.	3748.	3212.	1223.0	.0	2	11	7.0	30	60.	1.33	1.70
4	FDST	2	15.	58.	3673.	3148.	1223.0	.0	2	11	7.0	30	60.	1.33	1.70
5	GU12	2	25.	98.	3124.	2677.	1223.0	.0	2	11	7.0	30	100.	1.33	1.70
6	GU34	2	47.	188.	3124.	2677.	1223.0	.0	2	11	7.0	30	200.	1.33	1.70
7	STM1	1	12.	52.	5537.	4766.	1223.0	.0	2	11	10.0	30	50.	1.33	1.70
8	QTST	2	2.	6.	4950.	4242.	1020.0	.0	0	11	7.0	30	10.	4.17	4.00
9	GUCC	2	146.	291.	2715.	1812.	1223.0	.0	2	11	12.0	30	300.	.58	3.00
10	KACC	2	142.	283.	2715.	1812.	1223.0	.0	2	11	12.0	30	300.	.58	3.00
11	FDCC	1	61.	122.	3574.	2386.	1223.0	.0	2	11	12.0	30	150.	.58	3.00
12	KOCC	1	61.	122.	3574.	2386.	1223.0	.0	2	11	12.0	30	150.	.58	3.00
13	JOF1	1	60.	241.	2547.	2183.	.0	1199.0	4	11	7.0	30	250.	1.33	1.70
14	JOF2	3	50.	200.	2547.	2183.	.0	1199.0	4	11	17.0	30	200.	1.33	1.70
15	MUZ1	0	53.	210.	2547.	2183.	.0	1199.0	4	11	12.0	30	250.	1.33	1.70
16	GTG1	1	260.	260.	3932.	3932.	1223.0	.0	2	0	10.0	20	300.	1.00	4.20
17	GTG2	1	160.	160.	4833.	4833.	1223.0	.0	6	0	10.0	20	200.	1.00	4.20
18	KTP2	2	30.	118.	4862.	4166.	1223.0	.0	2	11	7.0	30	150.	1.33	1.70
19	BQSM	5	53.	210.	2905.	2490.	.0	1199.0	4	11	8.0	30	250.	1.33	1.70
20	LFBC	0	13.	50.	3038.	2629.	1020.0	.0	0	11	12.0	42	50.	3.80	4.00
21	KTP1	2	16.	62.	4862.	4166.	1223.0	.0	2	20	7.0	30	100.	1.33	1.70
22	KAC2	0	184.	283.	3359.	2241.	1223.0	.0	2	11	12.0	30	400.	.58	3.00
23	KAGT	6	45.	90.	3907.	2601.	1223.0	.0	2	20	10.0	30	100.	1.00	4.20
24	KAC3	0	150.	300.	3359.	2241.	1223.0	.0	2	11	12.0	30	300.	.58	3.00
25	GCC2	0	202.	404.	2792.	1864.	1223.0	.0	2	11	12.0	30	400.	.58	3.00
26	MUZ2	0	80.	320.	2547.	2183.	.0	1199.0	4	11	17.0	30	300.	1.33	1.70
27	CHNU	0	160.	325.	2707.	2433.	275.4	.0	7	11	9.0	42	350.	3.37	.70
28	HUB	0	81.	323.	2827.	2423.	.0	1199.0	4	11	7.0	30	350.	1.33	1.70
29	JOF3	0	88.	350.	2547.	2183.	.0	1199.0	4	11	17.0	30	350.	1.33	1.70
30	KANP	1	70.	70.	2838.	2838.	205.0	.0	7	0	22.0	45	100.	1.00	2.50

FIXED SYSTEM

SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD1

*** CAPACITY IN MW * ENERGY IN GWH ***

FIXED O&M COSTS : 1.590 $/KW-MONTH

YEAR	PROJ	PER	HYDROCONDITION 1 PROB.: .30 CAPACITY BASE	CAPACITY PEAK	ENERGY	HYDROCONDITION 2 PROB.: .40 CAPACITY BASE	CAPACITY PEAK	ENERGY	HYDROCONDITION 3 PROB.: .30 CAPACITY BASE	CAPACITY PEAK	ENERGY
1993	1	1	1178.	1.	1721.	1656.	2.	2420.	1976.	1.	2886.
		2	1042.	924.	1604.	1568.	405.	2392.	1559.	418.	2378.
		3	1240.	556.	1941.	1317.	479.	2034.	1300.	496.	2014.
		4	571.	857.	897.	841.	587.	1322.	862.	566.	1337.
		5	635.	201.	979.	676.	160.	1027.	745.	91.	1112.
		6	410.	178.	600.	651.	6.	951.	900.	1.	1315.
		INST.CAP. 1750.									
		TOTAL ENERGY			7742.			10146.			11042.
1994	3	1	0.	3584.	3811.	0.	3401.	4852.	0.	3597.	5033.
		2	0.	3563.	3309.	0.	3563.	3664.	0.	3623.	2966.
		3	0.	2533.	1430.	0.	2533.	1462.	0.	3199.	1473.
		4	0.	1939.	892.	0.	1946.	916.	0.	2607.	1282.
		5	0.	1390.	672.	0.	1429.	806.	0.	2205.	819.
		6	0.	1624.	1816.	0.	1529.	1893.	0.	3121.	3770.
		INST.CAP. 3478.									
		TOTAL ENERGY			11930.			13593.			15343.
2007	5	1	0.	3549.	4109.	0.	3401.	4852.	0.	3597.	5033.
		2	0.	3563.	3309.	0.	3563.	3664.	0.	3728.	3437.
		3	0.	2533.	1454.	0.	2533.	1491.	0.	3199.	1300.
		4	0.	2125.	637.	0.	2056.	650.	0.	2854.	1176.
		5	0.	2093.	473.	0.	1928.	782.	0.	2761.	892.
		6	0.	2621.	2775.	0.	2485.	2925.	0.	3188.	4513.
		INST.CAP. 3478.									
		TOTAL ENERGY			12757.			14364.			16351.

FIXED SYSTEM (CONTD.)

SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD1

*** CAPACITY IN MW * ENERGY IN GWH ***

FIXED O&M COSTS : 1.590 $/KW-MONTH

	PROJ		HYDROCONDITION 1 PROB.: .30			HYDROCONDITION 2 PROB.: .40			HYDROCONDITION 3 PROB.: .30		
		PER	CAPACITY		ENERGY	CAPACITY		ENERGY	CAPACITY		ENERGY
YEAR			BASE	PEAK		BASE	PEAK		BASE	PEAK	
2009	6	1	0.	0.	0.	0.	0.	0.	0.	0.	0.
		2	0.	0.	0.	0.	0.	0.	0.	0.	0.
		3	0.	0.	0.	0.	0.	0.	0.	0.	0.
		4	0.	0.	0.	0.	0.	0.	0.	0.	0.
		5	0.	0.	0.	0.	0.	0.	0.	0.	0.
		6	0.	0.	0.	0.	0.	0.	0.	0.	0.
		INST.CAP.		0.							
		TOTAL ENERGY			0.			0.			0.
1993	3	1	487.	708.	892.	972.	227.	1485.	1143.	64.	1757.
		2	352.	832.	621.	782.	405.	1233.	862.	333.	1337.
		3	539.	596.	910.	572.	547.	952.	579.	547.	961.
		4	342.	650.	578.	515.	470.	847.	591.	444.	941.
		5	408.	431.	674.	750.	181.	1131.	934.	141.	1428.
		6	461.	572.	767.	1004.	128.	1505.	1134.	62.	1741.
		INST.CAP.		1136.							
		TOTAL ENERGY			4443.			7151.			8165.
1995	5	1	535.	810.	1593.	541.	830.	1807.	499.	880.	1994.
		2	374.	960.	1478.	457.	880.	1548.	388.	956.	1273.
		3	361.	797.	817.	385.	914.	990.	352.	953.	924.
		4	165.	443.	255.	350.	550.	574.	357.	625.	670.
		5	384.	731.	909.	452.	615.	1169.	430.	740.	1084.
		6	541.	807.	1783.	545.	804.	1725.	511.	856.	1731.
		INST.CAP.		1406.							
		TOTAL ENERGY			6836.			7811.			7676.
1998	6	1	685.	810.	1812.	692.	830.	2027.	636.	880.	2193.
		2	505.	960.	1669.	581.	880.	1728.	535.	956.	1487.
		3	451.	797.	948.	473.	914.	1118.	486.	953.	1120.
		4	250.	443.	379.	444.	550.	712.	460.	625.	820.
		5	485.	731.	1057.	576.	615.	1350.	556.	740.	1268.
		6	709.	807.	2028.	717.	804.	1976.	679.	856.	1977.
		INST.CAP.		1590.							
		TOTAL ENERGY			7894.			8909.			8865.
2002	7	1	1503.	1442.	3346.	1493.	1457.	3537.	1404.	1498.	3655.
		2	1300.	1615.	3169.	1387.	1523.	3245.	1108.	1834.	2663.
		3	972.	1726.	2048.	1009.	1827.	2241.	838.	2051.	1974.
		4	595.	1257.	1223.	807.	1348.	1581.	903.	1341.	1808.
		5	717.	1949.	1736.	985.	1657.	2286.	749.	1997.	1889.
		6	1490.	1475.	3509.	1509.	1461.	3473.	1464.	1522.	3462.
		INST.CAP.		3040.							
		TOTAL ENERGY			15032.			16361.			15451.

FIXED SYSTEM
THERMAL ADDITIONS AND RETIREMENTS
NUMBER OF SETS ADDED AND RETIRED(-)
1993 TO 2022

YEAR: 19.. (200./20..)

NO.	NAME	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
3	MULT	-	-	-	-	-	-	-	-	-2	-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	FDST	-	-	-	-	-	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	GU12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-	-
6	GU34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-	-1	-	-
7	STM1	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	QTST	-	-	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	GUCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-	-	-
10	KACC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-
11	FDCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-
12	KOCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-
13	JOF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-
14	JOF2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-1	-1
15	MUZ1	1	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	GTG1	-	-	-	-	-	-	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	GTG2	-	-	-	-	-	-	-	-	-	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	KTP2	-	-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	BQSM	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-1	-	-	-	-	-1	-1	-1	-
20	LFBC	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	KTP1	-	-	-	-	-	-	-1	-	-	-	-	-	-	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	KAC2	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	KAGT	-	-	-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	KAC3	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	GCC2	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-
26	MUZ2	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	CHNU	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	HUB	-	-	-	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	JOF3	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	KANP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1	-	-	-	-	-	-	-	-	-	-	-

FIXED SYSTEM
SUMMARY OF INSTALLED CAPACITIES
(NOMINAL CAPACITIES (MW))

	HYDROELECTRIC				THERMAL										TOTAL
	HYD1		HYD2		FUEL TYPE										
					0	1	2	3	4	5	6	7	8	9	
YEAR	PR.	CAP	PR.	CAP	DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	
1993	1	1750.	3	1136.	12.	0.	3528.	0.	1891.	0.	160.	70.	0.	0.	8547.
1994	3	3478.	3	1136.	12.	0.	3528.	0.	2101.	0.	160.	70.	0.	0.	10485.
1995	3	3478.	5	1406.	162.	0.	3696.	0.	2731.	0.	160.	70.	0.	0.	11703.
1996					162.	0.	4022.	0.	2941.	0.	160.	70.	0.	0.	12239.
1997					162.	0.	4022.	0.	4440.	0.	160.	70.	0.	0.	13738.
1998	3	3478.	6	1590.	162.	0.	4022.	0.	5113.	0.	160.	70.	0.	0.	14595.
1999					162.	0.	4022.	0.	5113.	0.	160.	395.	0.	0.	14920.
2000					162.	0.	3700.	0.	5113.	0.	160.	395.	0.	0.	14598.
2002	3	3478.	7	3040.	162.	0.	3582.	0.	5113.	0.	160.	395.	0.	0.	15930.
2003					162.	0.	3464.	0.	5113.	0.	0.	395.	0.	0.	15652.
2004					150.	0.	3464.	0.	5113.	0.	0.	395.	0.	0.	15640.
2005					150.	0.	3412.	0.	5113.	0.	0.	395.	0.	0.	15588.
2007	5	3478.	7	3040.	150.	0.	3234.	0.	5113.	0.	0.	395.	0.	0.	15410.
2009	6	0.	7	3040.											11932.
2011					150.	0.	3234.	0.	5113.	0.	0.	325.	0.	0.	11862.
2013					150.	0.	2652.	0.	4903.	0.	0.	325.	0.	0.	11070.
2014					150.	0.	2456.	0.	4693.	0.	0.	325.	0.	0.	10664.
2015					150.	0.	1890.	0.	4693.	0.	0.	325.	0.	0.	10098.
2016					150.	0.	1702.	0.	4693.	0.	0.	325.	0.	0.	9910.
2019					150.	0.	1458.	0.	4242.	0.	0.	325.	0.	0.	9215.
2020					150.	0.	866.	0.	3832.	0.	0.	325.	0.	0.	8213.
2021					150.	0.	866.	0.	3422.	0.	0.	325.	0.	0.	7803.
2022					150.	0.	866.	0.	3222.	0.	0.	325.	0.	0.	7603.

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VARIABLE SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	HEAT RATES KCAL/KWH AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FUEL COSTS CENTS/ MILLION KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
1	FOL3	0	75.	300.	2827.	2423.	.0	1199.0	4	11	7.0	28	300.	1.33	1.70
2	FOL6	0	150.	600.	2827.	2423.	.0	1199.0	4	11	7.0	28	600.	1.33	1.70
3	COAL	0	150.	600.	2852.	2444.	.0	902.0	1	11	10.0	42	600.	1.25	2.10
4	WFGD	0	150.	600.	2908.	2493.	.0	902.0	1	11	12.0	42	600.	1.70	2.50
5	DCOL	0	25.	100.	3067.	2565.	1020.0	.0	0	11	13.0	42	100.	3.00	4.00
6	CCIG	0	225.	450.	2493.	1664.	.0	1223.0	3	11	12.0	28	450.	.58	3.00
7	GTIG	0	100.	100.	3151.	3151.	.0	1223.0	3	0	10.0	21	100.	1.00	4.20
8	NUCL	0	300.	600.	2603.	2340.	.0	194.2	7	7	10.0	42	600.	2.50	.50

VARIABLE SYSTEM

SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD1

*** CAPACITY IN MW * ENERGY IN GWH ***

FIXED O&M COSTS : 1.590 $/KW-MONTH

YEAR	PROJ	PER	HYDROCONDITION 1 PROB.: .30 CAPACITY BASE	PEAK	ENERGY	HYDROCONDITION 2 PROB.: .40 CAPACITY BASE	PEAK	ENERGY	HYDROCONDITION 3 PROB.: .30 CAPACITY BASE	PEAK	ENERGY
2006	1	1	0.	1345.	1100.	0.	1374.	1685.	0.	1364.	1847.
		2	0.	1353.	846.	0.	1349.	877.	0.	1388.	803.
		3	0.	1187.	387.	0.	1177.	384.	0.	1388.	399.
		4	0.	949.	313.	0.	916.	294.	0.	1157.	354.
		5	0.	760.	249.	0.	762.	320.	0.	1371.	374.
		6	0.	683.	650.	0.	755.	671.	0.	809.	950.
	INST.CAP. 1200.										
	TOTAL ENERGY				3545.			4231.			4727.
2007	2	1	0.	2690.	2200.	0.	2748.	3370.	0.	2728.	3694.
		2	0.	2706.	1692.	0.	2698.	1754.	0.	2776.	1606.
		3	0.	2374.	774.	0.	2354.	768.	0.	2776.	798.
		4	0.	1898.	626.	0.	1832.	588.	0.	2314.	708.
		5	0.	1520.	498.	0.	1524.	640.	0.	2742.	748.
		6	0.	1366.	1300.	0.	1510.	1342.	0.	1618.	1900.
	INST.CAP. 2400.										
	TOTAL ENERGY				7090.			8462.			9454.
2009	3	1	0.	7061.	6920.	0.	7187.	9160.	0.	7253.	10015.
		2	0.	7189.	5005.	0.	7181.	5646.	0.	7443.	5109.
		3	0.	5632.	2228.	0.	5612.	2258.	0.	6892.	2098.
		4	0.	4631.	1263.	0.	4477.	1238.	0.	5986.	1884.
		5	0.	4213.	971.	0.	4005.	1422.	0.	6295.	1640.
		6	0.	4663.	4366.	0.	4956.	4463.	0.	5629.	6942.
	INST.CAP. 6838.										
	TOTAL ENERGY				20753.			24187.			27688.
2011	4	1	0.	7825.	7684.	0.	8043.	10401.	0.	8109.	11263.
		2	0.	7985.	5840.	0.	7979.	6496.	0.	8283.	5970.
		3	0.	6163.	2409.	0.	6225.	2503.	0.	7732.	2424.
		4	0.	5096.	1421.	0.	5048.	1446.	0.	6661.	2091.
		5	0.	4639.	1127.	0.	4464.	1692.	0.	6977.	1852.
		6	0.	5301.	5053.	0.	5755.	5284.	0.	6469.	7997.
	INST.CAP. 7678.										
	TOTAL ENERGY				23534.			27822.			31597.
2012	5	1	0.	8589.	8448.	0.	8899.	11642.	0.	8965.	12511.
		2	0.	8781.	6675.	0.	8777.	7346.	0.	9123.	6831.
		3	0.	6694.	2590.	0.	6838.	2748.	0.	8572.	2750.
		4	0.	5561.	1579.	0.	5619.	1654.	0.	7336.	2298.
		5	0.	5065.	1283.	0.	4923.	1962.	0.	7659.	2064.
		6	0.	5939.	5740.	0.	6554.	6105.	0.	7309.	9052.
	INST.CAP. 8518.										
	TOTAL ENERGY				26315.			31457.			35506.
2013	6	1	0.	9353.	9212.	0.	9755.	12883.	0.	9821.	13759.
		2	0.	9577.	7510.	0.	9575.	8196.	0.	9963.	7692.
		3	0.	7225.	2771.	0.	7451.	2993.	0.	9412.	3076.
		4	0.	6026.	1737.	0.	6190.	1862.	0.	8011.	2505.
		5	0.	5491.	1439.	0.	5382.	2232.	0.	8341.	2276.
		6	0.	6577.	6427.	0.	7353.	6926.	0.	8149.	10107.
	INST.CAP. 9358.										
	TOTAL ENERGY				29096.			35092.			39415.

VARIABLE SYSTEM (CONTD.)

SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD1

*** CAPACITY IN MW * ENERGY IN GWH ***

FIXED O&M COSTS : 1.590 $/KW-MONTH

YEAR	PROJ	PER	HYDROCONDITION 1 PROB.: .30 CAPACITY BASE	PEAK	ENERGY	HYDROCONDITION 2 PROB.: .40 CAPACITY BASE	PEAK	ENERGY	HYDROCONDITION 3 PROB.: .30 CAPACITY BASE	PEAK	ENERGY
2014	7	1	0.	10117.	9976.	0.	10611.	14124.	0.	10677.	15007.
		2	0.	10373.	8345.	0.	10373.	9046.	0.	10803.	8553.
		3	0.	7756.	2952.	0.	8064.	3238.	0.	10252.	3402.
		4	0.	6491.	1895.	0.	6761.	2070.	0.	8686.	2712.
		5	0.	5917.	1595.	0.	5841.	2502.	0.	9023.	2488.
		6	0.	7215.	7114.	0.	8152.	7747.	0.	8989.	11162.
		INST.CAP.	10198.								
		TOTAL ENERGY			31877.			38727.			43324.
2003	1	1	127.	0.	186.	127.	0.	186.	127.	0.	186.
		2	104.	0.	152.	104.	0.	152.	104.	0.	152.
		3	77.	0.	113.	77.	0.	113.	77.	0.	113.
		4	66.	0.	96.	66.	0.	96.	66.	0.	96.
		5	82.	0.	119.	82.	0.	119.	82.	0.	119.
		6	138.	0.	202.	138.	0.	202.	138.	0.	202.
		INST.CAP.	144.								
		TOTAL ENERGY			868.			868.			868.
2005	2	1	215.	0.	314.	240.	0.	350.	241.	0.	352.
		2	193.	0.	282.	212.	0.	310.	212.	0.	310.
		3	127.	0.	185.	134.	0.	195.	129.	0.	189.
		4	96.	0.	140.	107.	0.	156.	110.	0.	160.
		5	131.	0.	191.	154.	0.	225.	175.	0.	255.
		6	238.	0.	348.	249.	0.	364.	240.	0.	350.
		INST.CAP.	264.								
		TOTAL ENERGY			1460.			1600.			1616.
2008	3	1	1145.	0.	1672.	1223.	0.	1786.	1329.	0.	1941.
		2	477.	0.	697.	660.	0.	964.	721.	0.	1053.
		3	395.	0.	577.	321.	0.	469.	297.	0.	434.
		4	240.	0.	351.	405.	0.	591.	355.	0.	518.
		5	953.	0.	1392.	1104.	0.	1612.	1236.	0.	1805.
		6	1379.	0.	2014.	1404.	0.	2050.	1306.	0.	1907.
		INST.CAP.	1264.								
		TOTAL ENERGY			6703.			7472.			7658.

C O N G E N

CONSTRAINTS ON CONFIGURATIONS GENERATED

CON: NUMBER OF CONFIGURATIONS

MIMIMUM

MAXIMUM

YEAR	CON	RES. MAR-GIN	FOL3	FOL6	COAL	WPGD	DCOL	CCIG	GTIG	NUCL	HYD1	HYD2
			PERMITTED EXTREME CONFIGURATIONS OF ALTERNATIVES									
1993	1	-4	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1994	1	-4	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1995	1	-4	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1996	1	-4	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1997	1	5	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1998	1	10	0	0	0	0	0	0	0	0	0	0
		20	0	0	0	0	0	0	0	0	0	0
1999	2	10	0	0	0	0	0	0	0	0	0	0
		25	0	0	0	0	0	1	0	0	0	0
2000	4	11	0	0	0	0	1	0	0	0	0	0
		25	0	0	1	0	1	2	2	0	0	0
2001	8	12	0	0	0	0	2	2	0	0	0	0
		25	0	0	2	0	2	4	2	0	0	0
2002	34	13	0	0	0	0	3	2	0	0	0	0
		25	0	0	2	0	3	5	3	1	0	0
2003	29	14	0	0	0	0	4	3	0	0	0	0
		25	0	0	2	0	4	6	4	1	0	1
2004	27	15	0	0	0	0	5	5	0	0	0	0
		25	0	0	3	0	5	8	5	1	0	1
2005	44	15	0	0	1	0	6	7	0	1	0	0
		25	0	0	3	0	6	10	6	2	0	2
2006	69	15	0	0	1	0	7	9	2	1	0	1
		25	0	0	4	0	7	12	6	2	1	2
2007	128	15	0	0	1	0	8	9	2	2	0	2
		25	0	0	4	0	8	13	7	3	2	2
2008	87	15	0	0	1	0	9	9	3	3	1	2
		25	0	0	4	0	9	13	8	4	2	3
2009	158	15	0	0	1	0	10	11	6	4	1	3
		25	0	1	4	0	10	15	10	5	3	3
2010	123	15	0	0	1	0	10	14	7	5	3	3
		25	0	2	4	0	10	17	11	6	3	3
2011	131	15	0	0	2	0	10	15	15	6	4	3
		25	0	2	5	0	10	18	19	7	4	3
2012	60	15	0	0	3	0	10	17	17	6	5	3
		25	0	2	6	0	10	20	22	8	5	3
2013	76	15	0	0	5	0	10	20	23	7	6	3
		25	0	2	8	0	10	23	29	9	6	3
2014	76	15	0	0	7	0	10	23	25	8	7	3
		25	0	2	10	0	10	26	31	10	7	3
2015	168	15	0	0	9	0	10	27	34	9	7	3
		25	0	3	12	0	10	30	39	11	7	3
2016	65	15	0	0	11	0	10	30	39	10	7	3
		25	0	3	14	0	10	33	45	12	7	3
2017	184	15	0	0	13	0	10	34	43	11	7	3
		25	0	5	16	0	10	37	49	13	7	3
2018	116	15	0	2	15	0	10	38	43	12	7	3
		25	0	7	18	0	10	41	48	14	7	3
2019	145	15	0	3	17	0	10	42	52	14	7	3
		25	0	8	20	0	10	45	61	16	7	3
2020	69	15	0	10	18	0	10	43	58	16	7	3
		25	0	15	21	0	10	45	65	18	7	3
2021	65	15	0	17	20	0	10	44	67	18	7	3
		25	0	21	23	0	10	45	73	20	7	3
2022	97	15	0	23	22	0	10	45	77	20	7	3
		25	0	28	25	0	10	45	83	22	7	3

1971 TOTAL NUMBER OF CONFIGURATIONS GENERATED

OPTIMUM SOLUTION

ANNUAL ADDITIONS: CAPACITY(MW) AND NUMBER OF UNITS OR PROJECTS

FOR DETAILS OF INDIVIDUAL UNITS OR PROJECTS SEE VARIABLE SYSTEM REPORT

SEE ALSO FIXED SYSTEM REPORT FOR OTHER ADDITIONS OR RETIREMENTS

NAME:				FOL3	FOL6	COAL	WFGD	DCOL	CCIG	GTIG	NUCL	HYD1	HYD2
SIZE (MW):				300.	600.	600.	600.	100.	450.	100.	600.	0.	0.
	%LOLP												
YEAR	MAINT	NOMNT	CAP										
1993	9.753		0.	-	-	-	-	-	-	-	-	-	-
1994	2.079		0.	-	-	-	-	-	-	-	-	-	-
1995	.556		0.	-	-	-	-	-	-	-	-	-	-
1996	.894		0.	-	-	-	-	-	-	-	-	-	-
1997	.142		0.	-	-	-	-	-	-	-	-	-	-
1998	.135		0.	-	-	-	-	-	-	-	-	-	-
1999	.670		0.	-	-	-	-	-	-	-	-	-	-
2000	.549		1600.	-	-	1	-	1	2	-	-	-	-
2001	.698		1100.	-	-	-	-	1	2	1	-	-	-
2002	.409		100.	-	-	-	-	1	-	-	-	-	-
2003	.348		1844.	-	-	-	-	1	2	1	1	-	1
2004	.329		1700.	-	-	1	-	1	2	1	-	-	-
2005	.352		1820.	-	-	-	-	1	2	1	1	-	1
2006	.232		2400.	-	-	-	-	1	2	2	-	1	-
2007	.435		1150.	-	-	-	-	1	1	-	1	-	-
2008	.203		2900.	-	-	-	-	1	-	-	1	1	1
2009	.299		5888.	-	-	-	-	1	1	3	1	1	-
2010	.428		2650.	-	-	1	-	-	3	1	1	-	-
2011	.445		3190.	-	-	1	-	-	1	7	1	1	-
2012	.276		3940.	-	-	2	-	-	2	4	1	1	-
2013	.131		4590.	-	-	2	-	-	3	6	1	1	-
2014	.135		4190.	-	-	2	-	-	3	2	1	1	-
2015	.167		4400.	-	-	2	-	-	4	8	1	-	-
2016	.180		4450.	-	1	2	-	-	3	7	1	-	-
2017	.220		4500.	-	1	2	-	-	4	3	1	-	-
2018	.275		4950.	-	3	2	-	-	3	-	1	-	-
2019	.302		6100.	-	1	2	-	-	4	13	2	-	-
2020	.290		6850.	-	7	1	-	-	1	4	2	-	-
2021	.293		6700.	-	6	2	-	-	-	7	2	-	-
2022	.300		7000.	-	6	2	-	-	-	10	2	-	-
TOTALS			84012.	0	25	25	0	10	45	81	22	7	3

SUMMARY OF

FIXED SYSTEM PLUS OPTIMUM SOLUTION

(NOMINAL CAPACITY (MW))

					THERMAL FUEL TYPE CAPACITIES						TOTAL CAP
YEAR	0	1	2	3	4	5	6	7	8	9	
	DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	
1993	12	0	3528	0	1891	0	160	70	0	0	5661
1994	12	0	3528	0	2101	0	160	70	0	0	5871
1995	162	0	3696	0	2731	0	160	70	0	0	6819
1996	162	0	4022	0	2941	0	160	70	0	0	7355
1997	162	0	4022	0	4440	0	160	70	0	0	8854
1998	162	0	4022	0	5113	0	160	70	0	0	9527
1999	162	0	4022	0	5113	0	160	395	0	0	9852
2000	262	600	3700	900	5113	0	160	395	0	0	11130
2001	362	600	3700	1900	5113	0	160	395	0	0	12230
2002	462	600	3582	1900	5113	0	160	395	0	0	12212
2003	562	600	3464	2900	5113	0	0	995	0	0	13634
2004	650	1200	3464	3900	5113	0	0	995	0	0	15322
2005	750	1200	3412	4900	5113	0	0	1595	0	0	16970
2006	850	1200	3412	6000	5113	0	0	1595	0	0	18170
2007	950	1200	3234	6450	5113	0	0	2195	0	0	19142
2008	1050	1200	3234	6450	5113	0	0	2795	0	0	19842
2009	1150	1200	3234	7200	5113	0	0	3395	0	0	21292
2010	1150	1800	3234	8650	5113	0	0	3995	0	0	23942
2011	1150	2400	3234	9800	5113	0	0	4525	0	0	26222
2012	1150	3600	3234	11100	5113	0	0	5125	0	0	29322
2013	1150	4800	2652	13050	4903	0	0	5725	0	0	32280
2014	1150	6000	2456	14600	4693	0	0	6325	0	0	35224
2015	1150	7200	1890	17200	4693	0	0	6925	0	0	39058
2016	1150	8400	1702	19250	5293	0	0	7525	0	0	43320
2017	1150	9600	1702	21350	5893	0	0	8125	0	0	47820
2018	1150	10800	1702	22700	7693	0	0	8725	0	0	52770
2019	1150	12000	1458	25800	7842	0	0	9925	0	0	58175
2020	1150	12600	866	26650	11632	0	0	11125	0	0	64023
2021	1150	13800	866	27350	14822	0	0	12325	0	0	70313
2022	1150	15000	866	28350	18222	0	0	13525	0	0	77113

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY IN MW, ENERGY IN GWH)

YEAR	HYDROELECTRIC HYD1 PR.	HYD1 CAP	HYD2 PR.	HYD2 CAP	TOTAL THERMAL CAPACITY	TOTAL CAP	SYSTEM RES. %	SYSTEM LOLP. %	ENERGY NOT SERVED HYDROCONDITION 1	2	3
1993	1	1750	3	1136	5661	8547	12.7	9.753	1016.6	207.0	84.3
1994	3	3478	3	1136	5871	10485	29.0	2.079	98.5	41.4	.5
1995	3	3478	5	1406	6819	11703	34.4	.556	6.3	7.5	.1
1996	3	3478	5	1406	7355	12239	31.1	.894	15.4	18.1	.0
1997	3	3478	5	1406	8854	13738	37.4	.142	1.4	1.9	.2
1998	3	3478	6	1590	9527	14595	36.2	.135	1.2	1.4	.2
1999	3	3478	6	1590	9852	14920	28.4	.670	11.3	12.7	.5
2000	3	3478	6	1590	11130	16198	28.7	.549	10.0	11.1	.2
2001	3	3478	6	1590	12230	17298	26.8	.698	14.4	16.1	.2
2002	3	3478	7	3040	12212	18730	26.7	.409	5.8	6.1	.4
2003	3	3478	8	3184	13634	20296	26.6	.348	5.4	5.8	.0
2004	3	3478	8	3184	15322	21984	26.3	.329	5.8	6.4	.3
2005	3	3478	9	3304	16970	23752	25.7	.352	6.9	7.3	.7
2006	4	4678	9	3304	18170	26152	27.5	.232	4.7	4.4	.3
2007	6	4678	9	3304	19142	27124	21.7	.435	6.7	7.1	2.2
2008	7	5878	10	4304	19842	30024	24.1	.203	4.8	4.6	1.7
2009	9	6838	10	4304	21292	32434	22.8	.299	6.2	5.9	2.2
2010	9	6838	10	4304	23942	35084	21.7	.428	7.9	7.1	4.6
2011	10	7678	10	4304	26222	38204	21.4	.445	7.9	8.0	5.7
2012	11	8518	10	4304	29322	42144	22.7	.276	9.6	9.8	6.7
2013	12	9358	10	4304	32280	45942	22.5	.131	11.8	10.6	7.3
2014	13	10198	10	4304	35224	49726	22.4	.135	14.1	12.8	8.2
2015	13	10198	10	4304	39058	53560	21.7	.167	16.5	16.7	9.7
2016	13	10198	10	4304	43320	57822	21.3	.180	15.5	16.6	8.2
2017	13	10198	10	4304	47820	62322	20.7	.220	12.3	15.1	6.0
2018	13	10198	10	4304	52770	67272	20.3	.275	16.1	17.3	11.4
2019	13	10198	10	4304	58175	72677	19.9	.302	21.1	24.5	18.7
2020	13	10198	10	4304	64023	78525	19.6	.290	28.0	31.9	27.8
2021	13	10198	10	4304	70313	84815	19.2	.293	31.3	37.5	34.5
2022	13	10198	10	4304	77113	91615	18.8	.300	31.2	39.4	38.6

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL STOCK OF THERMAL PLANTS BY FUEL TYPE (KTON)
THERMAL FUEL TYPES

YEAR	0 DCOL DOM.	DCOL FOR	1 ICOL DOM.	ICOL FOR	2 DGAS DOM.	DGAS FOR	3 IGAS DOM.	IGAS FOR	4 HSFO DOM.	HSFO FOR
1992	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1993	.00	.00	.00	.00	.00	.00	.00	.00	*********	*********
1994	*********	*********	.00	.00	*********	*********	.00	.00	*********	*********
1995	.00	.00	.00	.00	*********	*********	.00	.00	*********	*********
1996	.00	.00	.00	.00	.00	.00	.00	.00	*********	*********
1997	.00	.00	.00	.00	.00	.00	.00	.00	*********	*********
1998	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1999	*********	*********	*********	*********	.00	.00	*********	*********	.00	.00
2000	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2001	*********	*********	.00	.00	.00	.00	.00	.00	.00	.00
2002	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2003	*********	*********	*********	*********	.00	.00	*********	*********	.00	.00
2004	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2005	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2006	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2007	*********	*********	.00	.00	.00	.00	.00	.00	.00	.00
2008	*********	*********	.00	.00	.00	.00	*********	*********	.00	.00
2009	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2010	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2011	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2012	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2013	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2014	.00	.00	*********	*********	.00	.00	*********	*********	.00	.00
2015	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2016	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2017	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2018	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2019	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2020	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********
2021	.00	.00	*********	*********	.00	.00	*********	*********	*********	*********

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL STOCK OF THERMAL PLANTS BY FUEL TYPE (KTON)
THERMAL FUEL TYPES

YEAR	5 LSFO DOM.	5 LSFO FOR	6 HSD DOM.	6 HSD FOR	7 NUCL DOM.	7 NUCL FOR	8 **** DOM.	8 **** FOR	9 **** DOM.	9 **** FOR
1992	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1993	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1994	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1995	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1996	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1997	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1998	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
1999	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2000	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2001	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2002	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2003	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2004	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2005	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2006	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2007	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2008	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2009	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2010	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2011	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2012	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2013	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2014	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2015	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2016	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2017	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2018	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2019	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2020	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00
2021	.00	.00	.00	.00	*********	*********	.00	.00	.00	.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
GENERATIONS BY PLANT TYPE (GWH)
HYDROCONDITION 1
THERMAL FUEL TYPES

YEAR	HYDROELECTRIC HYD1	HYD2	TOTAL	0 DCOL	1 ICOL	2 DGAS	3 IGAS	4 HSFO	5 LSFO	6 HSD	7 NUCL	8 ****	9 ****	TOTAL	GR. TOTAL
1993	7742	4443	12185	60	0	21632	0	13102	0	321	419	0	0	35534	47719
1994	11930	4443	16373	56	0	20184	0	15027	0	70	419	0	0	35756	52129
1995	11930	6836	18766	827	0	18861	0	17085	0	6	419	0	0	37198	55964
1996	11930	6836	18766	867	0	21162	0	18742	0	11	419	0	0	41201	59967
1997	11930	6836	18766	924	0	19434	0	24737	0	1	419	0	0	45515	64281
1998	11930	7894	19824	920	0	19452	0	28221	0	1	419	0	0	49013	68837
1999	11930	7894	19824	1043	0	19993	0	31015	0	7	2713	0	0	54771	74595
2000	11930	7894	19824	1672	4188	17558	6407	28480	0	5	2713	0	0	61023	80847
2001	11930	7894	19824	2281	4188	17472	13558	27576	0	7	2713	0	0	67795	87619
2002	11930	15032	26962	2819	4188	17046	13558	27679	0	3	2713	0	0	68006	94968
2003	11930	15900	27830	2943	4188	15976	20700	24727	0	0	6901	0	0	75435	103265
2004	11930	15900	27830	2706	8375	15160	27813	23347	0	0	6901	0	0	84302	112132
2005	11930	16492	28422	2538	8375	14424	34862	22049	0	0	11089	0	0	93337	121759
2006	15475	16492	31967	2698	8375	14013	42722	21353	0	0	11088	0	0	100249	132216
2007	16302	16492	32794	4901	8375	15503	41575	25142	0	0	15275	0	0	110771	143565
2008	19847	21735	41582	5046	8375	15628	41552	25494	0	0	19463	0	0	115558	157140
2009	20753	21735	42488	7014	8375	16857	44858	28292	0	0	23651	0	0	129047	171535
2010	20753	21735	42488	6575	12563	16161	54261	27361	0	0	27838	0	0	144759	187247
2011	23534	21735	45269	6992	16750	17098	57756	28929	0	0	31607	0	0	159132	204401
2012	26315	21735	48050	6350	25125	16407	63790	27617	0	0	35794	0	0	175083	223133
2013	29096	21735	50831	5435	33501	12407	73371	26438	0	0	39982	0	0	191134	241965
2014	31877	21735	53612	5232	41875	11433	82489	23288	0	0	44169	0	0	208486	262098
2015	31877	21735	53612	5175	50249	8489	94979	23049	0	0	48357	0	0	230298	283910
2016	31877	21735	53612	5239	58625	7808	104358	25343	0	0	52545	0	0	253918	307530
2017	31877	21735	53612	5181	67000	7279	116449	26863	0	0	56732	0	0	279504	333116
2018	31877	21735	53612	4454	75375	7171	125637	29582	0	0	60919	0	0	303138	356750
2019	31877	21735	53612	4515	83749	6354	138839	30213	0	0	69294	0	0	332964	386576
2020	31877	21735	53612	5082	87938	3367	144036	47184	0	0	77670	0	0	365277	418889
2021	31877	21735	53612	6349	96313	3037	145217	63336	0	0	86045	0	0	400297	453909
2022	31877	21735	53612	7137	104689	2769	146223	83010	0	0	94420	0	0	438248	491860

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
GENERATIONS BY PLANT TYPE (GWH)
HYDROCONDITION 2
THERMAL FUEL TYPES

	HYDROELECTRIC			0	1	2	3	4	5	6	7	8	9		GR.
YEAR	HYD1	HYD2	TOTAL	DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	TOTAL	TOTAL
1993	10146	7151	17297	38	0	18507	0	12178	0	89	419	0	0	31231	48528
1994	13593	7151	20744	34	0	17750	0	13214	0	26	419	0	0	31443	52187
1995	13593	7811	21404	840	0	17066	0	16227	0	7	419	0	0	34559	55963
1996	13593	7811	21404	828	0	19280	0	18021	0	12	419	0	0	38560	59964
1997	13593	7811	21404	828	0	18215	0	23414	0	1	419	0	0	42877	64281
1998	13593	8909	22502	831	0	18364	0	26720	0	1	419	0	0	46335	68837
1999	13593	8909	22502	878	0	19281	0	29212	0	8	2713	0	0	52092	74594
2000	13593	8909	22502	1438	4188	16872	6407	26720	0	6	2713	0	0	58344	80846
2001	13593	8909	22502	1868	4188	16732	13558	26048	0	8	2713	0	0	65115	87617
2002	13593	16361	29954	2403	4188	16105	13558	26043	0	4	2713	0	0	65014	94968
2003	13593	17229	30822	2602	4188	15131	20700	22921	0	0	6901	0	0	72443	103265
2004	13593	17229	30822	2388	8375	14419	27778	21449	0	0	6901	0	0	81310	112132
2005	13593	17961	31554	2096	8375	13757	34730	20158	0	0	11089	0	0	90205	121759
2006	17824	17961	35785	2181	8375	13459	42134	19194	0	0	11088	0	0	96431	132216
2007	18595	17961	36556	3981	8375	14698	41554	23125	0	0	15275	0	0	107008	143564
2008	22826	23833	46659	4328	8375	14614	41186	22515	0	0	19463	0	0	110481	157140
2009	24187	23833	48020	6276	8375	15730	44740	24745	0	0	23651	0	0	123517	171537
2010	24187	23833	48020	5844	12563	15300	54114	23569	0	0	27838	0	0	139228	187248
2011	27822	23833	51655	6195	16750	15845	57361	24991	0	0	31607	0	0	152749	204404
2012	31457	23833	55290	5360	25125	15177	62972	23415	0	0	35794	0	0	167843	223133
2013	35092	23833	58925	5121	33500	11365	70826	22246	0	0	39982	0	0	183040	241965
2014	38727	23833	62560	4099	41874	10195	79476	19724	0	0	44169	0	0	199537	262097
2015	38727	23833	62560	4305	50248	7061	91767	19607	0	0	48357	0	0	221345	283905
2016	38727	23833	62560	4681	58623	6632	101108	21376	0	0	52545	0	0	244965	307525
2017	38727	23833	62560	4409	66999	6372	113164	22876	0	0	56732	0	0	270552	333112
2018	38727	23833	62560	4282	75373	6186	121085	26343	0	0	60919	0	0	294188	356748
2019	38727	23833	62560	4428	83748	5440	134171	26928	0	0	69294	0	0	324009	386569
2020	38727	23833	62560	4820	87937	2677	140592	42631	0	0	77670	0	0	356327	418887
2021	38727	23833	62560	5758	96313	2671	143211	57349	0	0	86045	0	0	391347	453907
2022	38727	23833	62560	6704	104689	2361	145105	76000	0	0	94420	0	0	429279	491839

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
GENERATIONS BY PLANT TYPE (GWH)
HYDROCONDITION 3
THERMAL FUEL TYPES

	HYDROELECTRIC			0	1	2	3	4	5	6	7	8	9		GR.
YEAR	HYD1	HYD2	TOTAL	DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	TOTAL	TOTAL
1993	11042	8165	19207	35	0	17303	0	11641	0	46	419	0	0	29444	48651
1994	15343	8165	23508	28	0	15946	0	12326	0	0	419	0	0	28719	52227
1995	15343	7676	23019	775	0	16076	0	15682	0	0	419	0	0	32952	55971
1996	15343	7676	23019	817	0	18421	0	17307	0	0	419	0	0	36964	59983
1997	15343	7676	23019	803	0	17935	0	22106	0	0	419	0	0	41263	64282
1998	15343	8865	24208	821	0	18103	0	25287	0	0	419	0	0	44630	68838
1999	15343	8865	24208	863	0	18854	0	27968	0	0	2713	0	0	50398	74606
2000	15343	8865	24208	1372	4188	16349	6407	25619	0	0	2713	0	0	56648	80856
2001	15343	8865	24208	1894	4188	16262	13558	24809	0	0	2713	0	0	63424	87632
2002	15343	15451	30794	2418	4188	16087	13558	25217	0	0	2713	0	0	64181	94975
2003	15343	16319	31662	2526	4188	14933	20704	22357	0	0	6901	0	0	71609	103271
2004	15343	16319	31662	2452	8375	14619	27638	20490	0	0	6901	0	0	80475	112137
2005	15343	17067	32410	2294	8375	13654	34513	19430	0	0	11089	0	0	89355	121765
2006	20070	17067	37137	2291	8375	13261	41485	18583	0	0	11088	0	0	95083	132220
2007	21078	17067	38145	4078	8375	14450	41195	22053	0	0	15275	0	0	105426	143571
2008	25805	23109	48914	4556	8375	14178	40172	21486	0	0	19463	0	0	108230	157144
2009	27688	23109	50797	5549	8375	14982	43347	24840	0	0	23651	0	0	120744	171541
2010	27688	23109	50797	5373	12563	14567	52724	23390	0	0	27838	0	0	136455	187252
2011	31597	23109	54706	5544	16750	15214	55852	24735	0	0	31607	0	0	149702	204408
2012	35506	23109	58615	5211	25125	14102	61325	22965	0	0	35794	0	0	164522	223137
2013	39415	23109	62524	5061	33500	11052	68107	21748	0	0	39982	0	0	179450	241974
2014	43324	23109	66433	4112	41689	9637	76147	19920	0	0	44169	0	0	195674	262107
2015	43324	23109	66433	4164	50248	7079	87773	19862	0	0	48357	0	0	217483	283916
2016	43324	23109	66433	4320	58624	6351	97446	21815	0	0	52545	0	0	241101	307534
2017	43324	23109	66433	4329	67000	5774	109729	23125	0	0	56732	0	0	266689	333122
2018	43324	23109	66433	4171	75374	5681	117831	26334	0	0	60919	0	0	290310	356743
2019	43324	23109	66433	4264	83749	4779	131106	26939	0	0	69294	0	0	320131	386564
2020	43324	23109	66433	4694	87938	2457	138390	41298	0	0	77670	0	0	352447	418880
2021	43324	23109	66433	5262	96314	2278	141685	55875	0	0	86045	0	0	387459	453892
2022	43324	23109	66433	6340	104689	2422	143991	73539	0	0	94420	0	0	425401	491834

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED GENERATIONS BY PLANT TYPE (GWH),
WEIGHTED BY PROBABILITIES OF HYDRO CONDITIONS

	HYDROELECTRIC			THERMAL FUEL TYPES 0	1	2	3	4	5	6	7	8	9		
YEAR	HYD1	HYD2	TOTAL	DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	TOTAL	GR. TOTAL
1993	9694	6643	16337	43	0	19083	0	12294	0	146	419	0	0	31985	48322
1994	13619	6643	20262	39	0	17939	0	13491	0	32	419	0	0	31920	52182
1995	13619	7478	21097	817	0	17307	0	16321	0	5	419	0	0	34869	55966
1996	13619	7478	21097	836	0	19587	0	18023	0	8	419	0	0	38873	59970
1997	13619	7478	21097	849	0	18497	0	23419	0	1	419	0	0	43185	64282
1998	13619	8591	22210	854	0	18612	0	26740	0	1	419	0	0	46626	68836
1999	13619	8591	22210	923	0	19367	0	29380	0	5	2713	0	0	52388	74598
2000	13619	8591	22210	1489	4188	16921	6407	26918	0	4	2713	0	0	58640	80850
2001	13619	8591	22210	2000	4188	16813	13558	26135	0	5	2713	0	0	65412	87622
2002	13619	15689	29308	2532	4188	16382	13558	26286	0	2	2713	0	0	65661	94969
2003	13619	16557	30176	2682	4188	15325	20701	23294	0	0	6901	0	0	73091	103267
2004	13619	16557	30176	2502	8375	14701	27747	21731	0	0	6901	0	0	81957	112133
2005	13619	17252	30871	2288	8375	13926	34704	20507	0	0	11089	0	0	90889	121760
2006	17793	17252	35045	2369	8375	13566	42116	19658	0	0	11088	0	0	97172	132217
2007	18652	17252	35904	4286	8375	14865	41453	23409	0	0	15275	0	0	107663	143567
2008	22826	22986	45812	4612	8375	14787	40991	23100	0	0	19463	0	0	111328	157140
2009	24207	22986	47193	6279	8375	15844	44358	25837	0	0	23651	0	0	124344	171537
2010	24207	22986	47193	5922	12563	15338	53741	24653	0	0	27838	0	0	140055	187248
2011	27668	22986	50654	6239	16750	16032	57027	26096	0	0	31607	0	0	153751	204405
2012	31129	22986	54115	5612	25125	15224	62723	24541	0	0	35794	0	0	169019	223134
2013	34590	22986	57576	5197	33500	11584	70774	23354	0	0	39982	0	0	184391	241967
2014	38051	22986	61037	4443	41819	10399	79382	20852	0	0	44169	0	0	201064	262101
2015	38051	22986	61037	4524	50248	7495	91532	20716	0	0	48357	0	0	222872	283909
2016	38051	22986	61037	4740	58624	6900	100984	22698	0	0	52545	0	0	246491	307528
2017	38051	22986	61037	4616	67000	6465	113119	24147	0	0	56732	0	0	272079	333116
2018	38051	22986	61037	4300	75374	6330	121475	27312	0	0	60919	0	0	295710	356747
2019	38051	22986	61037	4405	83749	5516	134652	27917	0	0	69294	0	0	325533	386570
2020	38051	22986	61037	4861	87938	2818	140965	43597	0	0	77670	0	0	357849	418886
2021	38051	22986	61037	5787	96313	2663	143355	58703	0	0	86045	0	0	392866	453903
2022	38051	22986	61037	6725	104689	2501	145106	77365	0	0	94420	0	0	430806	491843

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 1
THERMAL FUEL TYPES

	0		1		2		3		4	
YEAR	DCOL		ICOL		DGAS		IGAS		HSFO	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
1993	25.36	.00	.00	.00	6029.91	.00	.00	.00	.00	3041.25
1994	23.82	.00	.00	.00	5548.13	.00	.00	.00	.00	3468.86
1995	219.20	.00	.00	.00	4891.37	.00	.00	.00	.00	3839.22
1996	229.51	.00	.00	.00	5434.32	.00	.00	.00	.00	4201.32
1997	244.09	.00	.00	.00	4971.37	.00	.00	.00	.00	5573.63
1998	243.10	.00	.00	.00	4973.92	.00	.00	.00	.00	6348.31
1999	275.16	.00	.00	.00	5113.46	.00	.00	.00	.00	7022.44
2000	435.06	.00	.00	1009.07	4246.87	.00	.00	1260.44	.00	6410.64
2001	590.17	.00	.00	1009.07	4229.22	.00	.00	2742.50	.00	6193.78
2002	726.56	.00	.00	1009.07	4105.64	.00	.00	2742.50	.00	6219.12
2003	757.51	.00	.00	1009.07	3847.61	.00	.00	4223.05	.00	5511.76
2004	691.17	.00	.00	2018.14	3669.86	.00	.00	5697.71	.00	5189.12
2005	648.07	.00	.00	2018.15	3489.17	.00	.00	7159.43	.00	4894.01
2006	688.73	.00	.00	2018.14	3400.03	.00	.00	8856.01	.00	4735.65
2007	1250.35	.00	.00	2018.02	3678.01	.00	.00	8179.59	.00	5621.55
2008	1287.52	.00	.00	2018.04	3709.30	.00	.00	8174.56	.00	5706.09
2009	1789.28	.00	.00	2018.05	4011.33	.00	.00	8833.54	.00	6379.29
2010	1677.11	.00	.00	3027.11	3844.13	.00	.00	10676.50	.00	6162.90
2011	1783.88	.00	.00	4036.17	4081.32	.00	.00	11393.93	.00	6541.23
2012	1620.00	.00	.00	6054.16	3912.12	.00	.00	12562.98	.00	6232.06
2013	1387.08	.00	.00	8072.28	3078.66	.00	.00	14480.59	.00	5954.12
2014	1335.24	.00	.00	10090.30	2825.75	.00	.00	16275.33	.00	5230.26
2015	1320.55	.00	.00	12108.07	2210.09	.00	.00	18765.78	.00	5186.42
2016	1336.99	.00	.00	14126.33	2028.83	.00	.00	20630.37	.00	5734.98
2017	1322.04	.00	.00	16144.42	1887.59	.00	.00	22996.56	.00	6107.10
2018	1136.50	.00	.00	18162.24	1868.07	.00	.00	24972.43	.00	6815.14
2019	1152.03	.00	.00	20180.16	1633.87	.00	.00	27677.75	.00	6939.43
2020	1296.67	.00	.00	21189.53	928.33	.00	.00	28641.62	.00	110[illegible].08
2021	1620.26	.00	.00	23207.69	838.10	.00	.00	28881.63	.00	14850.54
2022	1821.31	.00	.00	25225.85	762.59	.00	.00	29112.83	.00	19569.60

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 1
THERMAL FUEL TYPES

	5		6		7		8		9	
YEAR	LSFO		HSD		NUCL		****		****	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
1993	.00	.00	146.63	.00	.01	.00	.00	.00	.00	.00
1994	.00	.00	32.24	.00	.01	.00	.00	.00	.00	.00
1995	.00	.00	2.78	.00	.01	.00	.00	.00	.00	.00
1996	.00	.00	5.12	.00	.01	.00	.00	.00	.00	.00
1997	.00	.00	.50	.00	.01	.00	.00	.00	.00	.00
1998	.00	.00	.49	.00	.01	.00	.00	.00	.00	.00
1999	.00	.00	3.13	.00	.08	.00	.00	.00	.00	.00
2000	.00	.00	2.42	.00	.08	.00	.00	.00	.00	.00
2001	.00	.00	3.12	.00	.08	.00	.00	.00	.00	.00
2002	.00	.00	1.49	.00	.08	.00	.00	.00	.00	.00
2003	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2004	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2005	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2006	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2007	.00	.00	.00	.00	.47	.00	.00	.00	.00	.00
2008	.00	.00	.00	.00	.60	.00	.00	.00	.00	.00
2009	.00	.00	.00	.00	.72	.00	.00	.00	.00	.00
2010	.00	.00	.00	.00	.85	.00	.00	.00	.00	.00
2011	.00	.00	.00	.00	.97	.00	.00	.00	.00	.00
2012	.00	.00	.00	.00	1.10	.00	.00	.00	.00	.00
2013	.00	.00	.00	.00	1.22	.00	.00	.00	.00	.00
2014	.00	.00	.00	.00	1.35	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	1.48	.00	.00	.00	.00	.00
2016	.00	.00	.00	.00	1.61	.00	.00	.00	.00	.00
2017	.00	.00	.00	.00	1.74	.00	.00	.00	.00	.00
2018	.00	.00	.00	.00	1.86	.00	.00	.00	.00	.00
2019	.00	.00	.00	.00	2.12	.00	.00	.00	.00	.00
2020	.00	.00	.00	.00	2.38	.00	.00	.00	.00	.00
2021	.00	.00	.00	.00	2.63	.00	.00	.00	.00	.00
2022	.00	.00	.00	.00	2.89	.00	.00	.00	.00	.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 2
THERMAL FUEL TYPES

	0		1		2		3		4	
YEAR	DCOL		ICOL		DGAS		IGAS		HSFO	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
1993	15.97	.00	.00	.00	5050.70	.00	.00	.00	.00	2815.58
1994	14.21	.00	.00	.00	4823.45	.00	.00	.00	.00	3034.35
1995	222.34	.00	.00	.00	4426.80	.00	.00	.00	.00	3648.07
1996	219.15	.00	.00	.00	4966.06	.00	.00	.00	.00	4040.34
1997	219.21	.00	.00	.00	4695.51	.00	.00	.00	.00	5267.43
1998	219.99	.00	.00	.00	4735.92	.00	.00	.00	.00	5999.86
1999	232.32	.00	.00	.00	4949.91	.00	.00	.00	.00	6594.05
2000	374.81	.00	.00	1009.07	4096.96	.00	.00	1260.44	.00	5998.93
2001	484.16	.00	.00	1009.07	4067.99	.00	.00	2742.50	.00	5837.84
2002	620.38	.00	.00	1009.07	3902.61	.00	.00	2742.50	.00	5833.66
2003	670.40	.00	.00	1009.07	3666.44	.00	.00	4222.92	.00	5103.16
2004	609.72	.00	.00	2018.15	3510.05	.00	.00	5690.72	.00	4769.68
2005	535.38	.00	.00	2018.14	3345.39	.00	.00	7133.27	.00	4483.74
2006	556.78	.00	.00	2018.14	3279.95	.00	.00	8739.80	.00	4269.43
2007	1016.23	.00	.00	2018.02	3504.79	.00	.00	8175.58	.00	5158.75
2008	1104.50	.00	.00	2018.04	3484.53	.00	.00	8102.41	.00	5027.87
2009	1601.07	.00	.00	2018.05	3745.84	.00	.00	8802.09	.00	5554.15
2010	1490.93	.00	.00	3027.11	3643.42	.00	.00	10646.62	.00	5284.92
2011	1580.66	.00	.00	4036.17	3784.84	.00	.00	11288.10	.00	5624.77
2012	1367.28	.00	.00	6054.16	3622.97	.00	.00	12390.95	.00	5255.66
2013	1306.38	.00	.00	8072.23	2815.64	.00	.00	13951.23	.00	4993.74
2014	1045.68	.00	.00	10090.00	2511.63	.00	.00	15658.42	.00	4411.34
2015	1098.15	.00	.00	12107.67	1840.37	.00	.00	18099.48	.00	4395.74
2016	1193.94	.00	.00	14125.91	1727.39	.00	.00	19950.44	.00	4818.06
2017	1124.66	.00	.00	16144.17	1657.35	.00	.00	22312.40	.00	5180.83
2018	1092.52	.00	.00	18161.91	1599.64	.00	.00	24000.14	.00	6057.70
2019	1129.95	.00	.00	20179.88	1385.08	.00	.00	26679.76	.00	6217.41
2020	1230.08	.00	.00	21189.36	738.34	.00	.00	27879.88	.00	9951.86
2021	1469.49	.00	.00	23207.54	735.41	.00	.00	28401.44	.00	13453.51
2022	1710.70	.00	.00	25225.79	649.94	.00	.00	28810.48	.00	17906.85

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 2
THERMAL FUEL TYPES

YEAR	5 LSFO		6 HSD		7 NUCL		8 ****		9 ****	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
1993	.00	.00	40.82	.00	.01	.00	.00	.00	.00	.00
1994	.00	.00	12.08	.00	.01	.00	.00	.00	.00	.00
1995	.00	.00	3.25	.00	.01	.00	.00	.00	.00	.00
1996	.00	.00	5.65	.00	.01	.00	.00	.00	.00	.00
1997	.00	.00	.58	.00	.01	.00	.00	.00	.00	.00
1998	.00	.00	.50	.00	.01	.00	.00	.00	.00	.00
1999	.00	.00	3.47	.00	.08	.00	.00	.00	.00	.00
2000	.00	.00	2.68	.00	.08	.00	.00	.00	.00	.00
2001	.00	.00	3.45	.00	.08	.00	.00	.00	.00	.00
2002	.00	.00	1.63	.00	.08	.00	.00	.00	.00	.00
2003	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2004	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2005	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2006	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2007	.00	.00	.00	.00	.47	.00	.00	.00	.00	.00
2008	.00	.00	.00	.00	.60	.00	.00	.00	.00	.00
2009	.00	.00	.00	.00	.72	.00	.00	.00	.00	.00
2010	.00	.00	.00	.00	.85	.00	.00	.00	.00	.00
2011	.00	.00	.00	.00	.97	.00	.00	.00	.00	.00
2012	.00	.00	.00	.00	1.10	.00	.00	.00	.00	.00
2013	.00	.00	.00	.00	1.22	.00	.00	.00	.00	.00
2014	.00	.00	.00	.00	1.35	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	1.48	.00	.00	.00	.00	.00
2016	.00	.00	.00	.00	1.61	.00	.00	.00	.00	.00
2017	.00	.00	.00	.00	1.74	.00	.00	.00	.00	.00
2018	.00	.00	.00	.00	1.86	.00	.00	.00	.00	.00
2019	.00	.00	.00	.00	2.12	.00	.00	.00	.00	.00
2020	.00	.00	.00	.00	2.38	.00	.00	.00	.00	.00
2021	.00	.00	.00	.00	2.63	.00	.00	.00	.00	.00
2022	.00	.00	.00	.00	2.89	.00	.00	.00	.00	.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 3
THERMAL FUEL TYPES

YEAR	0 DCOL		1 ICOL		2 DGAS		3 IGAS		4 HSFO	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
1993	14.75	.00	.00	.00	4708.33	.00	.00	.00	.00	2685.97
1994	11.74	.00	.00	.00	4291.47	.00	.00	.00	.00	2822.74
1995	204.91	.00	.00	.00	4158.03	.00	.00	.00	.00	3521.96
1996	215.95	.00	.00	.00	4731.04	.00	.00	.00	.00	3872.40
1997	212.38	.00	.00	.00	4603.92	.00	.00	.00	.00	4953.98
1998	217.05	.00	.00	.00	4651.18	.00	.00	.00	.00	5655.83
1999	228.36	.00	.00	.00	4835.63	.00	.00	.00	.00	6300.62
2000	357.86	.00	.00	1009.07	3972.25	.00	.00	1260.44	.00	5738.92
2001	490.65	.00	.00	1009.07	3954.07	.00	.00	2742.50	.00	5548.05
2002	624.10	.00	.00	1009.07	3892.72	.00	.00	2742.50	.00	5645.47
2003	650.99	.00	.00	1009.07	3620.21	.00	.00	4223.76	.00	4977.54
2004	626.51	.00	.00	2018.14	3552.36	.00	.00	5663.34	.00	4549.21
2005	585.53	.00	.00	2018.14	3321.29	.00	.00	7090.86	.00	4314.37
2006	584.47	.00	.00	2018.15	3236.34	.00	.00	8612.71	.00	4129.59
2007	1040.95	.00	.00	2018.02	3449.52	.00	.00	8104.22	.00	4931.64
2008	1162.62	.00	.00	2018.04	3390.19	.00	.00	7902.91	.00	4813.62
2009	1415.93	.00	.00	2018.05	3575.81	.00	.00	8527.84	.00	5609.78
2010	1371.26	.00	.00	3027.11	3475.47	.00	.00	10372.44	.00	5273.62
2011	1414.57	.00	.00	4036.17	3636.68	.00	.00	10988.17	.00	5598.55
2012	1329.43	.00	.00	6054.16	3359.07	.00	.00	12064.87	.00	5191.10
2013	1291.00	.00	.00	8072.27	2729.84	.00	.00	13399.34	.00	4909.89
2014	1049.20	.00	.00	10045.47	2365.10	.00	.00	14981.26	.00	4479.69
2015	1062.49	.00	.00	12107.78	1843.73	.00	.00	17268.80	.00	4474.24
2016	1102.43	.00	.00	14126.12	1647.66	.00	.00	19173.34	.00	4936.27
2017	1104.47	.00	.00	16144.31	1491.04	.00	.00	21590.42	.00	5254.35
2018	1064.34	.00	.00	18162.23	1459.72	.00	.00	23353.18	.00	6061.34
2019	1088.11	.00	.00	20180.25	1211.02	.00	.00	26072.43	.00	6225.15
2020	1197.99	.00	.00	21189.65	678.37	.00	.00	27445.54	.00	9649.49
2021	1342.82	.00	.00	23207.80	628.24	.00	.00	28078.31	.00	13114.84
2022	1617.93	.00	.00	25225.85	669.07	.00	.00	28565.10	.00	17325.42

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)
HYDROCONDITION 3
THERMAL FUEL TYPES

YEAR	5 LSFO DOM.	5 LSFO FOR	6 HSD DOM.	6 HSD FOR	7 NUCL DOM.	7 NUCL FOR	8 **** DOM.	8 **** FOR	9 **** DOM.	9 **** FOR
1993	.00	.00	20.95	.00	.01	.00	.00	.00	.00	.00
1994	.00	.00	.21	.00	.01	.00	.00	.00	.00	.00
1995	.00	.00	.06	.00	.01	.00	.00	.00	.00	.00
1996	.00	.00	.14	.00	.01	.00	.00	.00	.00	.00
1997	.00	.00	.10	.00	.01	.00	.00	.00	.00	.00
1998	.00	.00	.12	.00	.01	.00	.00	.00	.00	.00
1999	.00	.00	.06	.00	.08	.00	.00	.00	.00	.00
2000	.00	.00	.06	.00	.08	.00	.00	.00	.00	.00
2001	.00	.00	.20	.00	.08	.00	.00	.00	.00	.00
2002	.00	.00	.13	.00	.08	.00	.00	.00	.00	.00
2003	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2004	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2005	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2006	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2007	.00	.00	.00	.00	.47	.00	.00	.00	.00	.00
2008	.00	.00	.00	.00	.60	.00	.00	.00	.00	.00
2009	.00	.00	.00	.00	.72	.00	.00	.00	.00	.00
2010	.00	.00	.00	.00	.85	.00	.00	.00	.00	.00
2011	.00	.00	.00	.00	.97	.00	.00	.00	.00	.00
2012	.00	.00	.00	.00	1.10	.00	.00	.00	.00	.00
2013	.00	.00	.00	.00	1.22	.00	.00	.00	.00	.00
2014	.00	.00	.00	.00	1.35	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	1.48	.00	.00	.00	.00	.00
2016	.00	.00	.00	.00	1.61	.00	.00	.00	.00	.00
2017	.00	.00	.00	.00	1.74	.00	.00	.00	.00	.00
2018	.00	.00	.00	.00	1.86	.00	.00	.00	.00	.00
2019	.00	.00	.00	.00	2.12	.00	.00	.00	.00	.00
2020	.00	.00	.00	.00	2.38	.00	.00	.00	.00	.00
2021	.00	.00	.00	.00	2.63	.00	.00	.00	.00	.00
2022	.00	.00	.00	.00	2.89	.00	.00	.00	.00	.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON),
WEIGHTED BY PROBABILITIES OF HYDRO CONDITIONS
THERMAL FUEL TYPES

YEAR	0 DCOL DOM.	0 DCOL FOR	1 ICOL DOM.	1 ICOL FOR	2 DGAS DOM.	2 DGAS FOR	3 IGAS DOM.	3 IGAS FOR	4 HSFO DOM.	4 HSFO FOR
1993	18.42	.00	.00	.00	5241.75	.00	.00	.00	.00	2844.40
1994	16.35	.00	.00	.00	4881.26	.00	.00	.00	.00	3101.22
1995	216.17	.00	.00	.00	4485.54	.00	.00	.00	.00	3667.59
1996	221.30	.00	.00	.00	5036.03	.00	.00	.00	.00	4038.25
1997	224.62	.00	.00	.00	4750.79	.00	.00	.00	.00	5265.25
1998	226.04	.00	.00	.00	4781.90	.00	.00	.00	.00	6001.18
1999	243.98	.00	.00	.00	4964.69	.00	.00	.00	.00	6634.54
2000	387.80	.00	.00	1009.07	4104.52	.00	.00	1260.44	.00	6044.44
2001	517.91	.00	.00	1009.07	4082.18	.00	.00	2742.50	.00	5857.69
2002	653.35	.00	.00	1009.07	3960.55	.00	.00	2742.50	.00	5892.84
2003	690.71	.00	.00	1009.07	3706.92	.00	.00	4223.21	.00	5188.05
2004	639.19	.00	.00	2018.14	3570.69	.00	.00	5684.60	.00	4829.37
2005	584.23	.00	.00	2018.15	3381.29	.00	.00	7128.39	.00	4556.01
2006	604.67	.00	.00	2018.15	3302.89	.00	.00	8736.54	.00	4367.34
2007	1093.88	.00	.00	2018.02	3540.17	.00	.00	8155.38	.00	5229.46
2008	1176.84	.00	.00	2018.04	3523.66	.00	.00	8064.21	.00	5167.06
2009	1601.99	.00	.00	2018.05	3774.48	.00	.00	8729.25	.00	5818.38
2010	1510.88	.00	.00	3027.11	3653.25	.00	.00	10573.33	.00	5544.92
2011	1591.80	.00	.00	4036.17	3829.34	.00	.00	11229.87	.00	5891.84
2012	1431.74	.00	.00	6054.16	3630.54	.00	.00	12344.74	.00	5529.21
2013	1325.97	.00	.00	8072.26	2868.81	.00	.00	13944.47	.00	5256.70
2014	1133.60	.00	.00	10076.73	2561.91	.00	.00	15640.35	.00	4677.52
2015	1154.17	.00	.00	12107.82	1952.29	.00	.00	18050.17	.00	4656.49
2016	1209.40	.00	.00	14126.10	1793.90	.00	.00	19921.29	.00	5128.60
2017	1177.82	.00	.00	16144.29	1676.53	.00	.00	22301.05	.00	5480.77
2018	1097.26	.00	.00	18162.11	1638.19	.00	.00	24097.74	.00	6286.02
2019	1124.02	.00	.00	20180.07	1407.50	.00	.00	26796.96	.00	6451.34
2020	1240.43	.00	.00	21189.50	777.34	.00	.00	27978.10	.00	10179.22
2021	1476.72	.00	.00	23207.67	734.07	.00	.00	28448.56	.00	13771.02
2022	1716.06	.00	.00	25225.82	689.47	.00	.00	28827.57	.00	18231.25

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON),
WEIGHTED BY PROBABILITIES OF HYDRO CONDITIONS
THERMAL FUEL TYPES

YEAR	5 LSFO DOM.	5 LSFO FOR	6 HSD DOM.	6 HSD FOR	7 NUCL DOM.	7 NUCL FOR	8 **** DOM.	8 **** FOR	9 **** DOM.	9 **** FOR
1993	.00	.00	66.60	.00	.01	.00	.00	.00	.00	.00
1994	.00	.00	14.57	.00	.01	.00	.00	.00	.00	.00
1995	.00	.00	2.15	.00	.01	.00	.00	.00	.00	.00
1996	.00	.00	3.84	.00	.01	.00	.00	.00	.00	.00
1997	.00	.00	.41	.00	.01	.00	.00	.00	.00	.00
1998	.00	.00	.38	.00	.01	.00	.00	.00	.00	.00
1999	.00	.00	2.35	.00	.08	.00	.00	.00	.00	.00
2000	.00	.00	1.81	.00	.08	.00	.00	.00	.00	.00
2001	.00	.00	2.38	.00	.08	.00	.00	.00	.00	.00
2002	.00	.00	1.14	.00	.08	.00	.00	.00	.00	.00
2003	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2004	.00	.00	.00	.00	.21	.00	.00	.00	.00	.00
2005	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2006	.00	.00	.00	.00	.34	.00	.00	.00	.00	.00
2007	.00	.00	.00	.00	.47	.00	.00	.00	.00	.00
2008	.00	.00	.00	.00	.60	.00	.00	.00	.00	.00
2009	.00	.00	.00	.00	.72	.00	.00	.00	.00	.00
2010	.00	.00	.00	.00	.85	.00	.00	.00	.00	.00
2011	.00	.00	.00	.00	.97	.00	.00	.00	.00	.00
2012	.00	.00	.00	.00	1.10	.00	.00	.00	.00	.00
2013	.00	.00	.00	.00	1.22	.00	.00	.00	.00	.00
2014	.00	.00	.00	.00	1.35	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	1.48	.00	.00	.00	.00	.00
2016	.00	.00	.00	.00	1.61	.00	.00	.00	.00	.00
2017	.00	.00	.00	.00	1.74	.00	.00	.00	.00	.00
2018	.00	.00	.00	.00	1.86	.00	.00	.00	.00	.00
2019	.00	.00	.00	.00	2.12	.00	.00	.00	.00	.00
2020	.00	.00	.00	.00	2.38	.00	.00	.00	.00	.00
2021	.00	.00	.00	.00	2.63	.00	.00	.00	.00	.00
2022	.00	.00	.00	.00	2.89	.00	.00	.00	.00	.00

D Y N P R O
SUMMARY OF CAPITAL COSTS OF ALTERNATIVES IN $/KW

PLANT	CAPITAL COSTS (DEPRECIABLE PART) DOMESTIC	FOREIGN	INCLUSIVE IDC %	CONSTR. TIME (YEARS)	PLANT LIFE (YEARS)	CAPITAL COSTS (NON-DEPREC. PART) DOMESTIC	FOREIGN
THERMAL PLANT CAPITAL COSTS							
FOL3	326.5	979.7	15.63	4.00	30.	.0	22.3
FOL6	288.9	866.8	15.63	4.00	30.	.0	22.3
COAL	349.7	1049.0	19.21	5.00	30.	.0	50.9
WFGD	410.0	1230.1	19.21	5.00	30.	.0	51.9
DCOL	381.2	1524.8	15.63	4.00	30.	40.1	.0
CCIG	172.8	691.2	11.92	3.00	25.	.0	18.6
GTIG	83.6	473.5	8.08	2.00	20.	.0	28.1
NUCL	659.5	1538.9	22.67	6.00	30.	.0	90.0
HYD1 - HYDRO PROJECT CAPITAL COSTS, PROJECT LIFE: 50.							
1	781.5	955.2	22.67	6.00			
2	781.5	955.2	22.67	6.00			
3	166.0	387.3	19.21	5.00			
4	738.4	902.5	22.67	6.00			
5	738.4	902.5	22.67	6.00			
6	738.4	902.5	22.67	6.00			
7	738.4	902.5	22.67	6.00			
HYD2 - HYDRO PROJECT CAPITAL COSTS, PROJECT LIFE: 50.							
1	790.5	1679.7	15.63	4.00			
2	611.2	1611.2	15.63	4.00			
3	773.3	945.2	22.67	6.00			

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                                        D Y N P R O
                                 ECONOMIC PARAMETERS AND CONSTRAINTS
                             ALL COSTS WILL BE DISCOUNTED TO YEAR      :   1993
                             BASE YEAR FOR ESCALATION CALCULATION IS :   1993
      1993 INITIAL VALUES :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           **************
           NAME OF ALTERNATIVES :
           FOL3  FOL6  COAL  WFGD  DCOL  CCIG  GTIG  NUCL  HYD1  HYD2
  DISCOUNT RATE APPLIED TO ALL DOMESTIC CAPITAL COSTS - %/YR    10.0
  DISCOUNT RATE APPLIED TO ALL FOREIGN  CAPITAL COSTS - %/YR    10.0
  ESCALATION RATIOS FOR CAPITAL COSTS ( 0)
  ___________________________________
  DOMESTIC 1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
  MAXIMUM NUMBER OF UNITS WHICH CAN  BE ADDED ( 0)
  __________________________________________
            50    50    50    50    50    50    50    50    50    50
  MINIMUM NUMBER OF UNITS WHICH MUST BE ADDED ( 0)
  __________________________________________
             0     0     0     0     0     0     0     0     0     0


                                        D Y N P R O  (CONTD.)
                                 ECONOMIC PARAMETERS AND CONSTRAINTS
      1993 INITIAL VALUES :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           **************
  FUEL TYPE:                   T  H  E  R  M  A  L                        HYDRO     ENERGY
            DCOL  ICOL  DGAS  IGAS  HSFO  LSFO  HSD   NUCL  ****  ****  HYD1  HYD2  NOT
                                                                                    SERVED
  DISCOUNT RATE APPLIED TO ALL DOMESTIC OPERATION COSTS - %/YR  (14)      10.0
  DISCOUNT RATE APPLIED TO ALL FOREIGN  OPERATION COSTS - %/YR  (15)      10.0
  ESCALATION RATIOS FOR OPERATING COSTS ( 0)
  _________________________________
  DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
  MULTIPLYING FACTOR FOR FUEL COSTS (17)
  _________________________________
  DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00

  COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2        CF3
  _______________________________________________
                                      ($/KWH)       1.0000      .0000      .0000
  PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 0)      1.0000
  CRITICAL LOSS OF LOAD PROBABILITY IN %  ( 0)    100.0000
  DEPRECIATION OPTION (16)  :  1 =
                                 SINKING FUND


                                        D Y N P R O
                            LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD
      1994 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           ********************************
  MULTIPLYING FACTOR FOR FUEL COSTS (17)
  _________________________________
  DOMESTIC  1.01  1.01  1.01  1.01  1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.01  1.01  1.01  1.01  1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00
      1995 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           ********************************
  MULTIPLYING FACTOR FOR FUEL COSTS (17)
  _________________________________
  DOMESTIC  1.02  1.02  1.02  1.02  1.02  1.02  1.02  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.02  1.02  1.02  1.02  1.02  1.02  1.02  1.00  1.00  1.00  1.00  1.00  1.00
      1996 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           ********************************
  MULTIPLYING FACTOR FOR FUEL COSTS (17)
  _________________________________
  DOMESTIC  1.03  1.03  1.03  1.03  1.03  1.03  1.03  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.03  1.03  1.03  1.03  1.03  1.03  1.03  1.00  1.00  1.00  1.00  1.00  1.00
      1997 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
           ********************************
  MULTIPLYING FACTOR FOR FUEL COSTS (17)
  _________________________________
  DOMESTIC  1.04  1.04  1.04  1.04  1.04  1.04  1.04  1.00  1.00  1.00  1.00  1.00  1.00
  FOREIGN   1.04  1.04  1.04  1.04  1.04  1.04  1.04  1.00  1.00  1.00  1.00  1.00  1.00
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D Y N P R O (CONTD.)
LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD
1998 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.00	1.00	1.00	1.00	1.00	1.00

1999 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.00	1.00	1.00	1.00	1.00	1.00

2000 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.00	1.00	1.00	1.00	1.00	1.00

2001 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.08	1.08	1.09	1.09	1.09	1.09	1.09	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.08	1.08	1.09	1.09	1.09	1.09	1.09	1.00	1.00	1.00	1.00	1.00	1.00

D Y N P R O (CONTD.)
LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD
2002 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.09	1.09	1.12	1.12	1.12	1.12	1.12	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.09	1.09	1.12	1.12	1.12	1.12	1.12	1.00	1.00	1.00	1.00	1.00	1.00

2003 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.10	1.10	1.14	1.14	1.14	1.14	1.14	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.10	1.10	1.14	1.14	1.14	1.14	1.14	1.00	1.00	1.00	1.00	1.00	1.00

2004 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.12	1.12	1.16	1.16	1.16	1.16	1.16	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.12	1.12	1.16	1.16	1.16	1.16	1.16	1.00	1.00	1.00	1.00	1.00	1.00

2005 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.13	1.13	1.18	1.18	1.18	1.18	1.18	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.13	1.13	1.18	1.18	1.18	1.18	1.18	1.00	1.00	1.00	1.00	1.00	1.00

D Y N P R O (CONTD.)
LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD
2006 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.14	1.14	1.21	1.21	1.21	1.21	1.21	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.14	1.14	1.21	1.21	1.21	1.21	1.21	1.00	1.00	1.00	1.00	1.00	1.00

2007 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.15	1.15	1.23	1.23	1.23	1.23	1.23	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.15	1.15	1.23	1.23	1.23	1.23	1.23	1.00	1.00	1.00	1.00	1.00	1.00

2008 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.16	1.16	1.26	1.26	1.26	1.26	1.26	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.16	1.16	1.26	1.26	1.26	1.26	1.26	1.00	1.00	1.00	1.00	1.00	1.00

2009 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ
****
MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.17	1.17	1.28	1.28	1.28	1.28	1.28	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.17	1.17	1.28	1.28	1.28	1.28	1.28	1.00	1.00	1.00	1.00	1.00	1.00

D Y N P R O (CONTD.)

LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD

2010 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

****

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.18	1.18	1.31	1.31	1.31	1.31	1.31	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.18	1.18	1.31	1.31	1.31	1.31	1.31	1.00	1.00	1.00	1.00	1.00	1.00

2011 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

****

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.20	1.20	1.34	1.34	1.34	1.34	1.34	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.20	1.20	1.34	1.34	1.34	1.34	1.34	1.00	1.00	1.00	1.00	1.00	1.00

2012 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

****

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.21	1.21	1.38	1.38	1.38	1.38	1.38	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.21	1.21	1.38	1.38	1.38	1.38	1.38	1.00	1.00	1.00	1.00	1.00	1.00

2013 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.22	1.22	1.42	1.42	1.42	1.42	1.42	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.22	1.22	1.42	1.42	1.42	1.42	1.42	1.00	1.00	1.00	1.00	1.00	1.00

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.23	1.23	1.45	1.45	1.45	1.45	1.45	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.23	1.23	1.45	1.45	1.45	1.45	1.45	1.00	1.00	1.00	1.00	1.00	1.00

2015 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.24	1.24	1.49	1.49	1.49	1.49	1.49	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.24	1.24	1.49	1.49	1.49	1.49	1.49	1.00	1.00	1.00	1.00	1.00	1.00

2016 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.26	1.26	1.53	1.53	1.53	1.53	1.53	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.26	1.26	1.53	1.53	1.53	1.53	1.53	1.00	1.00	1.00	1.00	1.00	1.00

2017 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.27	1.27	1.57	1.57	1.57	1.57	1.57	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.27	1.27	1.57	1.57	1.57	1.57	1.57	1.00	1.00	1.00	1.00	1.00	1.00

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.28	1.28	1.62	1.62	1.62	1.62	1.62	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.28	1.28	1.62	1.62	1.62	1.62	1.62	1.00	1.00	1.00	1.00	1.00	1.00

2019 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.30	1.30	1.66	1.66	1.66	1.66	1.66	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.30	1.30	1.66	1.66	1.66	1.66	1.66	1.00	1.00	1.00	1.00	1.00	1.00

2020 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.31	1.31	1.71	1.71	1.71	1.71	1.71	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.31	1.31	1.71	1.71	1.71	1.71	1.71	1.00	1.00	1.00	1.00	1.00	1.00

2021 YEAR WHEN NEW VALUES ARE IN FORCE : (XX) = INDEX NUMBER; (0) = NO INDEX READ

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MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.32	1.32	1.75	1.75	1.75	1.75	1.75	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.32	1.32	1.75	1.75	1.75	1.75	1.75	1.00	1.00	1.00	1.00	1.00	1.00

MULTIPLYING FACTOR FOR FUEL COSTS (17)

DOMESTIC	1.33	1.33	1.80	1.80	1.80	1.80	1.80	1.00	1.00	1.00	1.00	1.00	1.00
FOREIGN	1.33	1.33	1.80	1.80	1.80	1.80	1.80	1.00	1.00	1.00	1.00	1.00	1.00

EXPECTED COST OF OPERATION
FUEL COST
DOMESTIC

TYPE OF PLANT:		DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****
YEAR	TOTAL	COST BY PLANT TYPE (MILLION $)									
1993	714.7	2.1	.0	701.6	.0	.0	.0	8.6	2.4	.0	.0
1994	671.5	1.9	.0	665.3	.0	.0	.0	1.9	2.4	.0	.0
1995	654.9	24.2	.0	628.0	.0	.0	.0	.3	2.4	.0	.0
1996	736.9	25.0	.0	709.0	.0	.0	.0	.5	2.4	.0	.0
1997	709.4	25.6	.0	681.3	.0	.0	.0	.1	2.4	.0	.0
1998	720.7	26.0	.0	692.2	.0	.0	.0	.1	2.4	.0	.0
1999	767.8	28.2	.0	720.6	.0	.0	.0	.3	18.7	.0	.0
2000	674.0	45.3	.0	609.9	.0	.0	.0	.3	18.7	.0	.0
2001	699.8	61.1	.0	619.6	.0	.0	.0	.3	18.7	.0	.0
2002	711.0	77.9	.0	614.3	.0	.0	.0	.2	18.7	.0	.0
2003	695.8	83.8	.0	593.3	.0	.0	.0	.0	18.7	.0	.0
2004	686.8	79.4	.0	588.7	.0	.0	.0	.0	18.7	.0	.0
2005	668.8	74.8	.0	575.3	.0	.0	.0	.0	18.7	.0	.0
2006	674.6	78.9	.0	577.0	.0	.0	.0	.0	18.7	.0	.0
2007	770.0	138.6	.0	612.8	.0	.0	.0	.0	18.7	.0	.0
2008	792.5	150.8	.0	623.0	.0	.0	.0	.0	18.7	.0	.0
2009	893.9	204.6	.0	670.6	.0	.0	.0	.0	18.7	.0	.0
2010	880.6	195.6	.0	666.4	.0	.0	.0	.0	18.7	.0	.0
2011	934.0	207.5	.0	710.3	.0	.0	.0	.0	16.2	.0	.0
2012	903.8	189.7	.0	697.9	.0	.0	.0	.0	16.2	.0	.0
2013	768.0	178.2	.0	573.5	.0	.0	.0	.0	16.2	.0	.0
2014	701.0	155.4	.0	529.3	.0	.0	.0	.0	16.2	.0	.0
2015	591.7	159.6	.0	415.9	.0	.0	.0	.0	16.2	.0	.0
2016	577.5	168.3	.0	393.0	.0	.0	.0	.0	16.2	.0	.0
2017	563.5	165.7	.0	381.5	.0	.0	.0	.0	16.2	.0	.0
2018	546.1	156.7	.0	373.2	.0	.0	.0	.0	16.2	.0	.0
2019	504.7	161.8	.0	326.7	.0	.0	.0	.0	16.2	.0	.0
2020	382.7	179.3	.0	187.2	.0	.0	.0	.0	16.2	.0	.0
2021	410.1	213.4	.0	180.5	.0	.0	.0	.0	16.2	.0	.0
2022	438.5	248.5	.0	173.8	.0	.0	.0	.0	16.2	.0	.0
TOTALS	20445.1	3507.8	.0	16491.6	.0	.0	.0	12.5	433.2	.0	.0

EXPECTED COST OF OPERATION
FUEL COST
FOREIGN

TYPE OF PLANT:		DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****
YEAR	TOTAL	COST BY PLANT TYPE (MILLION $)									
1993	362.0	.0	.0	.0	.0	362.0	.0	.0	.0	.0	.0
1994	398.8	.0	.0	.0	.0	398.8	.0	.0	.0	.0	.0
1995	478.0	.0	.0	.0	.0	478.0	.0	.0	.0	.0	.0
1996	530.9	.0	.0	.0	.0	530.9	.0	.0	.0	.0	.0
1997	705.1	.0	.0	.0	.0	705.1	.0	.0	.0	.0	.0
1998	812.0	.0	.0	.0	.0	812.0	.0	.0	.0	.0	.0
1999	901.8	.0	.0	.0	.0	901.8	.0	.0	.0	.0	.0
2000	1111.6	.0	103.1	.0	174.6	833.9	.0	.0	.0	.0	.0
2001	1317.5	.0	104.1	.0	387.6	825.8	.0	.0	.0	.0	.0
2002	1347.5	.0	105.2	.0	395.3	847.0	.0	.0	.0	.0	.0
2003	1513.8	.0	106.2	.0	621.0	766.5	.0	.0	20.1	.0	.0
2004	1819.0	.0	214.6	.0	853.1	731.2	.0	.0	20.1	.0	.0
2005	2055.5	.0	216.7	.0	1092.1	706.5	.0	.0	40.2	.0	.0
2006	2319.8	.0	218.9	.0	1367.8	692.9	.0	.0	40.2	.0	.0
2007	2416.3	.0	221.1	.0	1299.1	835.8	.0	.0	60.3	.0	.0
2008	2460.0	.0	223.3	.0	1313.2	843.1	.0	.0	80.4	.0	.0
2009	2736.1	.0	225.5	.0	1448.7	961.4	.0	.0	100.5	.0	.0
2010	3189.9	.0	341.7	.0	1790.4	937.1	.0	.0	120.6	.0	.0
2011	3572.7	.0	460.1	.0	1952.8	1019.1	.0	.0	140.7	.0	.0
2012	4052.4	.0	697.1	.0	2208.8	985.8	.0	.0	160.8	.0	.0
2013	4655.0	.0	938.7	.0	2573.4	962.0	.0	.0	180.9	.0	.0
2014	5236.2	.0	1183.6	.0	2969.0	882.6	.0	.0	201.0	.0	.0
2015	6080.2	.0	1436.3	.0	3520.7	902.1	.0	.0	221.1	.0	.0
2016	6944.2	.0	1692.6	.0	3988.5	1021.9	.0	.0	241.2	.0	.0
2017	7923.8	.0	1953.6	.0	4585.1	1123.8	.0	.0	261.3	.0	.0
2018	8940.7	.0	2219.8	.0	5106.1	1333.4	.0	.0	281.4	.0	.0
2019	10044.4	.0	2491.2	.0	5828.3	1403.2	.0	.0	321.6	.0	.0
2020	11487.1	.0	2641.9	.0	6215.1	2268.3	.0	.0	361.8	.0	.0
2021	12933.7	.0	2922.5	.0	6468.8	3140.4	.0	.0	402.0	.0	.0
2022	14620.9	.0	3208.4	.0	6719.0	4251.4	.0	.0	442.2	.0	.0
TOTALS	122966.7	.0	23926.3	.0	62878.5	32463.7	.0	.0	3698.2	.0	.0

EXPECTED COST OF OPERATION
OPERATION & MAINTENANCE AND ENERGY NOT SERVED (ENS)
DOMESTIC

TYPE OF PLANT:		DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	HYD1	HYD2	ENS
YEAR	TOTAL					COST BY PLANT TYPE (MILLION $)								
1993	620.4	.8	.0	95.9	.0	51.1	.0	2.5	1.9	.0	.0	33.4	21.7	413.1
1994	288.4	.8	.0	93.0	.0	56.5	.0	2.1	1.9	.0	.0	66.4	21.7	46.2
1995	276.4	10.7	.0	92.4	.0	71.3	.0	1.9	1.9	.0	.0	66.4	26.8	4.9
1996	293.6	10.8	.0	96.4	.0	77.6	.0	2.0	1.9	.0	.0	66.4	26.8	11.9
1997	313.9	10.8	.0	94.2	.0	110.7	.0	1.9	1.9	.0	.0	66.4	26.8	1.2
1998	334.0	10.9	.0	94.6	.0	127.1	.0	1.9	1.9	.0	.0	66.4	30.3	1.0
1999	363.2	11.1	.0	96.7	.0	131.5	.0	1.9	16.6	.0	.0	66.4	30.3	8.6
2000	393.6	17.0	17.8	83.2	25.5	127.4	.0	1.9	16.6	.0	.0	66.4	30.3	7.5
2001	430.7	22.6	17.8	82.8	55.3	126.0	.0	1.9	16.6	.0	.0	66.4	30.3	10.8
2002	455.0	28.4	17.8	80.0	55.3	126.3	.0	1.9	16.6	.0	.0	66.4	58.0	4.3
2003	499.7	32.6	17.8	75.3	85.1	121.2	.0	.0	36.7	.0	.0	66.4	60.8	3.9
2004	545.2	34.8	35.6	73.4	114.6	118.5	.0	.0	36.7	.0	.0	66.4	60.8	4.4
2005	595.3	37.6	35.6	70.4	143.8	116.5	.0	.0	56.8	.0	.0	66.4	63.0	5.2
2006	650.3	41.5	35.6	69.3	176.5	115.0	.0	.0	56.8	.0	.0	89.3	63.0	3.3
2007	687.6	52.8	35.6	70.8	172.3	121.4	.0	.0	76.9	.0	.0	89.3	63.0	5.5
2008	750.6	57.7	35.6	70.6	170.9	120.9	.0	.0	97.0	.0	.0	112.2	82.1	3.8
2009	824.8	68.0	35.6	73.3	187.8	125.5	.0	.0	117.1	.0	.0	130.5	82.1	4.9
2010	898.3	66.5	53.4	72.0	226.5	123.5	.0	.0	137.2	.0	.0	130.5	82.1	6.6
2011	977.9	67.8	71.2	73.7	248.0	126.0	.0	.0	155.4	.0	.0	146.5	82.1	7.3
2012	1071.9	65.3	106.8	71.5	276.1	123.3	.0	.0	175.5	.0	.0	162.5	82.1	8.8
2013	1163.4	63.6	142.4	56.2	317.0	118.0	.0	.0	195.6	.0	.0	178.6	82.1	10.0
2014	1257.9	60.6	177.8	50.3	354.7	110.3	.0	.0	215.7	.0	.0	194.6	82.1	11.8
2015	1362.7	60.9	213.5	37.6	413.5	110.1	.0	.0	235.8	.0	.0	194.6	82.1	14.6
2016	1473.6	61.8	249.1	33.6	459.8	123.1	.0	.0	255.9	.0	.0	194.6	82.1	13.8
2017	1589.9	61.3	284.7	32.4	512.2	135.1	.0	.0	276.0	.0	.0	194.6	82.1	11.5
2018	1717.9	60.0	320.3	31.9	548.5	169.2	.0	.0	296.1	.0	.0	194.6	82.1	15.2
2019	1868.8	60.5	355.9	27.8	617.4	172.6	.0	.0	336.2	.0	.0	194.6	82.1	21.7
2020	2036.4	62.3	373.7	14.5	643.6	259.8	.0	.0	376.4	.0	.0	194.6	82.1	29.5
2021	2212.8	66.0	409.3	14.0	659.1	336.4	.0	.0	416.6	.0	.0	194.6	82.1	34.8
2022	2397.4	69.7	444.8	13.5	676.8	422.3	.0	.0	456.8	.0	.0	194.6	82.1	36.7
		1275.2		1941.4		4174.1		20.1		.0		3620.1		762.6
TOTALS	28351.7		3487.5		7140.0		.0		4085.2		.0		1845.6	

EXPECTED COST OF OPERATION
TOTAL COST
DOMESTIC AND FOREIGN

TYPE OF PLANT:		DCOL	ICOL	DGAS	IGAS	HSFO	LSFO	HSD	NUCL	****	****	HYD1	HYD2	ENS
YEAR	TOTAL					COST BY PLANT TYPE (MILLION $)								
1993	1697.0	2.9	.0	797.5	.0	413.0	.0	11.1	4.3	.0	.0	33.4	21.7	413.1
1994	1358.7	2.7	.0	758.3	.0	455.2	.0	4.0	4.3	.0	.0	66.4	21.7	46.2
1995	1409.2	34.9	.0	720.4	.0	549.3	.0	2.2	4.3	.0	.0	66.4	26.8	4.9
1996	1561.4	35.7	.0	805.4	.0	608.5	.0	2.5	4.3	.0	.0	66.4	26.8	11.9
1997	1728.4	36.4	.0	775.5	.0	815.8	.0	2.0	4.3	.0	.0	66.4	26.8	1.2
1998	1866.6	36.8	.0	786.8	.0	939.0	.0	2.0	4.3	.0	.0	66.4	30.3	1.0
1999	2032.9	39.3	.0	817.3	.0	1033.4	.0	2.3	35.3	.0	.0	66.4	30.3	8.6
2000	2179.2	62.2	120.9	693.0	200.1	961.3	.0	2.2	35.3	.0	.0	66.4	30.3	7.5
2001	2447.9	83.8	121.9	702.5	442.8	951.8	.0	2.3	35.3	.0	.0	66.4	30.3	10.8
2002	2513.5	106.3	123.0	694.3	450.6	973.3	.0	2.1	35.3	.0	.0	66.4	58.0	4.3
2003	2709.3	116.4	124.0	668.6	706.0	887.7	.0	.0	75.5	.0	.0	66.4	60.8	3.9
2004	3051.1	114.3	250.2	662.2	967.7	849.7	.0	.0	75.5	.0	.0	66.4	60.8	4.4
2005	3319.6	112.4	252.3	645.7	1235.9	822.9	.0	.0	115.7	.0	.0	66.4	63.0	5.2
2006	3644.7	120.4	254.5	646.3	1544.3	807.9	.0	.0	115.7	.0	.0	89.3	63.0	3.3
2007	3873.9	191.3	256.7	683.6	1471.3	957.2	.0	.0	155.9	.0	.0	89.3	63.0	5.5
2008	4003.2	208.5	258.9	693.6	1484.1	964.0	.0	.0	196.1	.0	.0	112.2	82.1	3.8
2009	4454.8	272.6	261.1	744.0	1636.5	1086.9	.0	.0	236.3	.0	.0	130.5	82.1	4.9
2010	4968.8	262.1	395.1	738.4	2016.9	1060.7	.0	.0	276.5	.0	.0	130.5	82.1	6.6
2011	5484.5	275.3	531.3	784.0	2200.8	1145.0	.0	.0	312.3	.0	.0	146.5	82.1	7.3
2012	6028.2	254.9	803.8	769.4	2484.9	1109.1	.0	.0	352.5	.0	.0	162.5	82.1	8.8
2013	6586.4	241.9	1081.1	629.7	2890.4	1080.0	.0	.0	392.7	.0	.0	178.6	82.1	10.0
2014	7195.1	216.0	1361.4	579.6	3323.7	992.9	.0	.0	432.9	.0	.0	194.6	82.1	11.8
2015	8034.6	220.5	1649.8	453.5	3934.1	1012.2	.0	.0	473.1	.0	.0	194.6	82.1	14.6
2016	8995.3	230.1	1941.7	426.6	4448.3	1145.0	.0	.0	513.3	.0	.0	194.6	82.1	13.8
2017	10077.1	227.0	2238.3	413.9	5097.3	1258.9	.0	.0	553.5	.0	.0	194.6	82.1	11.5
2018	11204.6	216.7	2540.1	405.1	5654.6	1502.6	.0	.0	593.7	.0	.0	194.6	82.1	15.2
2019	12417.8	222.2	2847.1	354.5	6445.7	1575.9	.0	.0	674.0	.0	.0	194.6	82.1	21.7
2020	13906.2	241.6	3015.6	201.7	6858.7	2528.1	.0	.0	754.4	.0	.0	194.6	82.1	29.5
2021	15556.6	279.4	3331.7	194.5	7128.0	3476.8	.0	.0	834.8	.0	.0	194.6	82.1	34.8
2022	17456.9	318.2	3653.2	187.4	7395.8	4673.7	.0	.0	915.2	.0	.0	194.6	82.1	36.7
		4783.0		18433.0		36637.9		32.6		.0		3620.1		762.6
TOTALS	171763.5		27413.7		70018.5		.0		8216.6		.0		1845.6	

DOMESTIC CONSTRUCTION COSTS (MILLION $)

YEAR	#	PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1	COAL	6.2	25.7	58.0	60.2	19.4	-	-	-	-	-	-	-	169.5
2000	1	DCOL	-	1.7	8.4	15.5	6.6	-	-	-	-	-	-	-	32.2
2000	2	CCIG	-	-	13.4	80.3	43.3	-	-	-	-	-	-	-	137.0
2001	1	DCOL	-	-	1.7	8.4	15.5	6.6	-	-	-	-	-	-	32.2
2001	2	CCIG	-	-	-	13.4	80.3	43.3	-	-	-	-	-	-	137.0
2001	1	GTIG	-	-	-	-	2.4	5.3	-	-	-	-	-	-	7.7
2002	1	DCOL	-	-	-	1.7	8.4	15.5	6.6	-	-	-	-	-	32.2
2003	1	DCOL	-	-	-	-	1.7	8.4	15.5	6.6	-	-	-	-	32.2
2003	2	CCIG	-	-	-	-	-	13.4	80.3	43.3	-	-	-	-	137.0
2003	1	GTIG	-	-	-	-	-	-	2.4	5.3	-	-	-	-	7.7
2003	1	NUCL	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	306.0
2003	1	JINH	-	-	-	-	5.0	25.1	46.3	19.6	-	-	-	-	96.0
2004	1	COAL	-	-	-	-	6.2	25.7	58.0	60.2	19.4	-	-	-	169.5
2004	1	DCOL	-	-	-	-	-	1.7	8.4	15.5	6.6	-	-	-	32.2
2004	2	CCIG	-	-	-	-	-	-	13.4	80.3	43.3	-	-	-	137.0
2004	1	GTIG	-	-	-	-	-	-	-	2.4	5.3	-	-	-	7.7
2005	1	DCOL	-	-	-	-	-	-	1.7	8.4	15.5	6.6	-	-	32.2
2005	2	CCIG	-	-	-	-	-	-	-	13.4	80.3	43.3	-	-	137.0
2005	1	GTIG	-	-	-	-	-	-	-	-	2.4	5.3	-	-	7.7
2005	1	NUCL	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	306.0
2005	1	TAUN	-	-	-	-	-	-	3.2	16.2	29.8	12.6	-	-	61.9
2006	1	DCOL	-	-	-	-	-	-	-	1.7	8.4	15.5	6.6	-	32.2
2006	2	CCIG	-	-	-	-	-	-	-	-	13.4	80.3	43.3	-	137.0
2006	2	GTIG	-	-	-	-	-	-	-	-	-	4.8	10.5	-	15.4
2006	1	KBG1	-	-	-	-	-	20.4	50.7	156.5	268.4	179.2	49.9	-	725.2
2007	1	DCOL	-	-	-	-	-	-	-	-	1.7	8.4	15.5	6.6	32.2
2007	1	CCIG	-	-	-	-	-	-	-	-	-	6.7	40.1	21.6	68.5
2007	1	NUCL	-	-	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	306.0
END		TOTAL	6.2	27.4	90.1	200.9	263.4	300.1	436.7	631.0	758.7	902.0	1060.7	974.3	

DOMESTIC CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	#	PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1	DCOL	-	-	1.7	8.4	15.5	6.6	-	-	-	-	-	-	32.2
2008	1	NUCL	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	-	-	306.0
2008	1	KBG2	20.4	50.7	156.5	268.4	179.2	49.9	-	-	-	-	-	-	725.2
2008	1	KOHA	16.9	41.8	129.1	221.3	147.8	41.2	-	-	-	-	-	-	598.0
2009	1	DCOL	-	-	-	1.7	8.4	15.5	6.6	-	-	-	-	-	32.2
2009	1	CCIG	-	-	-	-	6.7	40.1	21.6	-	-	-	-	-	68.5
2009	3	GTIG	-	-	-	-	-	7.2	15.8	-	-	-	-	-	23.0
2009	1	NUCL	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	-	306.0
2009	1	TA16	-	-	21.7	90.3	203.6	211.3	68.3	-	-	-	-	-	595.2
2010	1	COAL	-	-	-	6.2	25.7	58.0	60.2	19.4	-	-	-	-	169.5
2010	3	CCIG	-	-	-	-	-	20.2	120.4	64.9	-	-	-	-	205.5
2010	1	GTIG	-	-	-	-	-	-	2.4	5.3	-	-	-	-	7.7
2010	1	NUCL	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	306.0
2011	1	COAL	-	-	-	-	6.2	25.7	58.0	60.2	19.4	-	-	-	169.5
2011	1	CCIG	-	-	-	-	-	-	6.7	40.1	21.6	-	-	-	68.5
2011	7	GTIG	-	-	-	-	-	-	-	16.9	36.9	-	-	-	53.8
2011	1	NUCL	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	306.0
2011	1	BSH1	-	-	-	13.5	33.6	103.5	177.5	118.5	33.0	-	-	-	479.7
2012	2	COAL	-	-	-	-	-	12.4	51.4	116.0	120.3	38.9	-	-	339.0
2012	2	CCIG	-	-	-	-	-	-	-	13.4	80.3	43.3	-	-	137.0
2012	4	GTIG	-	-	-	-	-	-	-	-	9.6	21.1	-	-	30.7
2012	1	NUCL	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	306.0
2012	1	BSH2	-	-	-	-	13.5	33.6	103.5	177.5	118.5	33.0	-	-	479.7
2013	2	COAL	-	-	-	-	-	-	12.4	51.4	116.0	120.3	38.9	-	339.0
2013	3	CCIG	-	-	-	-	-	-	-	-	20.2	120.4	64.9	-	205.5
2013	6	GTIG	-	-	-	-	-	-	-	-	-	14.5	31.6	-	46.1
2013	1	NUCL	-	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	306.0
2013	1	BSH3	-	-	-	-	-	13.5	33.6	103.5	177.5	118.5	33.0	-	479.7
2014	2	COAL	-	-	-	-	-	-	-	12.4	51.4	116.0	120.3	38.9	339.0
2014	3	CCIG	-	-	-	-	-	-	-	-	-	20.2	120.4	64.9	205.5
2014	2	GTIG	-	-	-	-	-	-	-	-	-	-	4.8	10.5	15.4
2014	1	NUCL	-	-	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	306.0
END		TOTAL	631.0	758.7	902.0	1060.7	974.3	944.6	1057.9	1139.1	1226.7	1193.5	1052.8	1008.0	

DOMESTIC CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	# PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1 BSH4	13.5	33.6	103.5	177.5	118.5	33.0	-	-	-	-	-	-	479.7
2015	2 COAL	-	-	12.4	51.4	116.0	120.3	38.9	-	-	-	-	-	339.0
2015	4 CCIG	-	-	-	-	26.9	160.5	86.6	-	-	-	-	-	274.0
2015	8 GTIG	-	-	-	-	-	19.3	42.1	-	-	-	-	-	61.4
2015	1 NUCL	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	-	306.0
2016	1 FOL6	-	-	-	-	7.6	38.3	70.5	29.9	-	-	-	-	146.3
2016	2 COAL	-	-	-	12.4	51.4	116.0	120.3	38.9	-	-	-	-	339.0
2016	3 CCIG	-	-	-	-	-	20.2	120.4	64.9	-	-	-	-	205.5
2016	7 GTIG	-	-	-	-	-	-	16.9	36.9	-	-	-	-	53.8
2016	1 NUCL	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	-	306.0
2017	1 FOL6	-	-	-	-	-	7.6	38.3	70.5	29.9	-	-	-	146.3
2017	2 COAL	-	-	-	-	12.4	51.4	116.0	120.3	38.9	-	-	-	339.0
2017	4 CCIG	-	-	-	-	-	-	26.9	160.5	86.6	-	-	-	274.0
2017	3 GTIG	-	-	-	-	-	-	-	7.2	15.8	-	-	-	23.0
2017	1 NUCL	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	-	306.0
2018	3 FOL6	-	-	-	-	-	-	22.9	114.9	211.4	89.7	-	-	438.8
2018	2 COAL	-	-	-	-	-	12.4	51.4	116.0	120.3	38.9	-	-	339.0
2018	3 CCIG	-	-	-	-	-	-	-	20.2	120.4	64.9	-	-	205.5
2018	1 NUCL	-	-	-	-	8.6	21.4	66.0	113.3	75.6	21.1	-	-	306.0
2019	1 FOL6	-	-	-	-	-	-	-	7.6	38.3	70.5	29.9	-	146.3
2019	2 COAL	-	-	-	-	-	-	12.4	51.4	116.0	120.3	38.9	-	339.0
2019	4 CCIG	-	-	-	-	-	-	-	-	26.9	160.5	86.6	-	274.0
2019	13 GTIG	-	-	-	-	-	-	-	-	-	31.3	68.5	-	99.8
2019	2 NUCL	-	-	-	-	-	17.3	42.8	132.1	226.5	151.2	42.1	-	612.0
2020	7 FOL6	-	-	-	-	-	-	-	-	53.4	268.1	493.2	209.2	1023.8
2020	1 COAL	-	-	-	-	-	-	-	6.2	25.7	58.0	60.2	19.4	169.5
2020	1 CCIG	-	-	-	-	-	-	-	-	-	6.7	40.1	21.6	68.5
2020	4 GTIG	-	-	-	-	-	-	-	-	-	-	9.6	21.1	30.7
2020	2 NUCL	-	-	-	-	-	-	17.3	42.8	132.1	226.5	151.2	42.1	612.0
END	TOTAL	1057.9	1139.1	1226.7	1193.5	1052.8	1008.0	1099.5	1247.5	1411.2	1592.1	1821.8	1596.9	

DOMESTIC CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	# PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6 FOL6	-	-	45.7	229.8	422.7	179.3	-	877.5
2021	2 COAL	-	12.4	51.4	116.0	120.3	38.9	-	339.0
2021	7 GTIG	-	-	-	-	16.9	36.9	-	53.8
2021	2 NUCL	17.3	42.8	132.1	226.5	151.2	42.1	-	612.0
2022	6 FOL6	-	-	-	45.7	229.8	422.7	179.3	877.5
2022	2 COAL	-	-	12.4	51.4	116.0	120.3	38.9	339.0
2022	10 GTIG	-	-	-	-	-	24.1	52.7	76.8
2022	2 NUCL	-	17.3	42.8	132.1	226.5	151.2	42.1	612.0
END	TOTAL	1247.5	1411.2	1592.1	1821.8	1596.9	1015.6	313.0	23372.1

FOREIGN CONSTRUCTION COSTS (MILLION $)

YEAR	# PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1 COAL	18.6	77.2	173.9	180.5	58.3	-	-	-	-	-	-	-	508.5
2000	1 DCOL	-	6.7	33.7	62.0	26.3	-	-	-	-	-	-	-	128.6
2000	2 CCIG	-	-	53.8	321.1	173.1	-	-	-	-	-	-	-	548.0
2001	1 DCOL	-	-	6.7	33.7	62.0	26.3	-	-	-	-	-	-	128.6
2001	2 CCIG	-	-	-	53.8	321.1	173.1	-	-	-	-	-	-	548.0
2001	1 GTIG	-	-	-	-	13.7	29.9	-	-	-	-	-	-	43.5
2002	1 DCOL	-	-	-	6.7	33.7	62.0	26.3	-	-	-	-	-	128.6
2003	1 DCOL	-	-	-	-	6.7	33.7	62.0	26.3	-	-	-	-	128.6
2003	2 CCIG	-	-	-	-	-	53.8	321.1	173.1	-	-	-	-	548.0
2003	1 GTIG	-	-	-	-	-	-	13.7	29.9	-	-	-	-	43.5
2003	1 NUCL	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	714.0
2003	1 JINH	-	-	-	-	10.6	53.4	98.3	41.7	-	-	-	-	204.1
2004	1 COAL	-	-	-	-	18.6	77.2	173.9	180.5	58.3	-	-	-	508.5
2004	1 DCOL	-	-	-	-	-	6.7	33.7	62.0	26.3	-	-	-	128.6
2004	2 CCIG	-	-	-	-	-	-	53.8	321.1	173.1	-	-	-	548.0
2004	1 GTIG	-	-	-	-	-	-	-	13.7	29.9	-	-	-	43.5
2005	1 DCOL	-	-	-	-	-	-	6.7	33.7	62.0	26.3	-	-	128.6
2005	2 CCIG	-	-	-	-	-	-	-	53.8	321.1	173.1	-	-	548.0
2005	1 GTIG	-	-	-	-	-	-	-	-	13.7	29.9	-	-	43.5
2005	1 NUCL	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	714.0
2005	1 TAUN	-	-	-	-	-	-	8.5	42.7	78.6	33.3	-	-	163.1
2006	1 DCOL	-	-	-	-	-	-	-	6.7	33.7	62.0	26.3	-	128.6
2006	2 CCIG	-	-	-	-	-	-	-	-	53.8	321.1	173.1	-	548.0
2006	2 GTIG	-	-	-	-	-	-	-	-	-	27.3	59.7	-	87.0
2006	1 KBG1	-	-	-	-	-	25.0	62.0	191.3	328.1	219.0	61.0	-	886.3
2007	1 DCOL	-	-	-	-	-	-	-	-	6.7	33.7	62.0	26.3	128.6
2007	1 CCIG	-	-	-	-	-	-	-	-	-	26.9	160.5	86.6	274.0
2007	1 NUCL	-	-	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	714.0
END TOTAL		18.6	83.9	288.2	707.7	898.3	855.2	1210.5	1605.4	1698.8	1896.5	2092.2	1977.2	

FOREIGN CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	# PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1 DCOL	-	-	6.7	33.7	62.0	26.3	-	-	-	-	-	-	128.6
2008	1 NUCL	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	-	-	714.0
2008	1 KBG2	25.0	62.0	191.3	328.1	219.0	61.0	-	-	-	-	-	-	886.3
2008	1 KOHA	20.6	51.1	157.7	270.5	180.6	50.3	-	-	-	-	-	-	730.9
2009	1 DCOL	-	-	-	6.7	33.7	62.0	26.3	-	-	-	-	-	128.6
2009	1 CCIG	-	-	-	-	26.9	160.5	86.6	-	-	-	-	-	274.0
2009	3 GTIG	-	-	-	-	-	41.0	89.6	-	-	-	-	-	130.6
2009	1 NUCL	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	-	714.0
2009	1 TA16	-	-	50.7	210.7	475.0	493.0	159.3	-	-	-	-	-	1388.7
2010	1 COAL	-	-	-	18.6	77.2	173.9	180.5	58.3	-	-	-	-	508.5
2010	3 CCIG	-	-	-	-	-	80.7	481.6	259.7	-	-	-	-	821.9
2010	1 GTIG	-	-	-	-	-	-	13.7	29.9	-	-	-	-	43.5
2010	1 NUCL	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	714.0
2011	1 COAL	-	-	-	-	18.6	77.2	173.9	180.5	58.3	-	-	-	508.5
2011	1 CCIG	-	-	-	-	-	-	26.9	160.5	86.6	-	-	-	274.0
2011	7 GTIG	-	-	-	-	-	-	-	95.6	209.0	-	-	-	304.6
2011	1 NUCL	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	714.0
2011	1 BSH1	-	-	-	16.5	41.0	126.5	217.0	144.8	40.4	-	-	-	586.3
2012	2 COAL	-	-	-	-	-	37.1	154.3	347.9	361.0	116.7	-	-	1017.0
2012	2 CCIG	-	-	-	-	-	-	-	53.8	321.1	173.1	-	-	548.0
2012	4 GTIG	-	-	-	-	-	-	-	-	54.7	119.4	-	-	174.1
2012	1 NUCL	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	714.0
2012	1 BSH2	-	-	-	-	16.5	41.0	126.5	217.0	144.8	40.4	-	-	586.3
2013	2 COAL	-	-	-	-	-	-	37.1	154.3	347.9	361.0	116.7	-	1017.0
2013	3 CCIG	-	-	-	-	-	-	-	-	80.7	481.6	259.7	-	821.9
2013	6 GTIG	-	-	-	-	-	-	-	-	-	82.0	179.1	-	261.1
2013	1 NUCL	-	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	714.0
2013	1 BSH3	-	-	-	-	-	16.5	41.0	126.5	217.0	144.8	40.4	-	586.3
2014	2 COAL	-	-	-	-	-	-	-	37.1	154.3	347.9	361.0	116.7	1017.0
2014	3 CCIG	-	-	-	-	-	-	-	-	-	80.7	481.6	259.7	821.9
2014	2 GTIG	-	-	-	-	-	-	-	-	-	-	27.3	59.7	87.0
2014	1 NUCL	-	-	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	714.0
END TOTAL		1605.4	1698.8	1896.5	2092.2	1977.2	2161.0	2544.8	2621.0	2953.3	3070.0	2994.4	3080.7	

FOREIGN CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	#	PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1	BSH4	16.5	41.0	126.5	217.0	144.8	40.4	-	-	-	-	-	-	586.3
2015	2	COAL	-	-	37.1	154.3	347.9	361.0	116.7	-	-	-	-	-	1017.0
2015	4	CCIG	-	-	-	-	107.6	642.1	346.2	-	-	-	-	-	1095.9
2015	8	GTIG	-	-	-	-	-	109.3	238.8	-	-	-	-	-	348.2
2015	1	NUCL	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	-	714.0
2016	1	FOL6	-	-	-	-	22.9	114.9	211.3	89.7	-	-	-	-	438.8
2016	2	COAL	-	-	-	37.1	154.3	347.9	361.0	116.7	-	-	-	-	1017.0
2016	3	CCIG	-	-	-	-	-	80.7	481.6	259.7	-	-	-	-	821.9
2016	7	GTIG	-	-	-	-	-	-	95.6	209.0	-	-	-	-	304.6
2016	1	NUCL	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	-	714.0
2017	1	FOL6	-	-	-	-	-	22.9	114.9	211.3	89.7	-	-	-	438.8
2017	2	COAL	-	-	-	-	37.1	154.3	347.9	361.0	116.7	-	-	-	1017.0
2017	4	CCIG	-	-	-	-	-	-	107.6	642.1	346.2	-	-	-	1095.9
2017	3	GTIG	-	-	-	-	-	-	-	41.0	89.6	-	-	-	130.6
2017	1	NUCL	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	-	714.0
2018	3	FOL6	-	-	-	-	-	-	68.6	344.7	634.0	269.0	-	-	1316.3
2018	2	COAL	-	-	-	-	-	37.1	154.3	347.9	361.0	116.7	-	-	1017.0
2018	3	CCIG	-	-	-	-	-	-	-	80.7	481.6	259.7	-	-	821.9
2018	1	NUCL	-	-	-	-	20.1	49.9	154.1	264.3	176.4	49.2	-	-	714.0
2019	1	FOL6	-	-	-	-	-	-	-	22.9	114.9	211.3	89.7	-	438.8
2019	2	COAL	-	-	-	-	-	-	37.1	154.3	347.9	361.0	116.7	-	1017.0
2019	4	CCIG	-	-	-	-	-	-	-	-	107.6	642.1	346.2	-	1095.9
2019	13	GTIG	-	-	-	-	-	-	-	-	-	177.6	388.1	-	565.8
2019	2	NUCL	-	-	-	-	-	40.3	99.9	308.2	528.5	352.8	98.3	-	1428.0
2020	7	FOL6	-	-	-	-	-	-	-	-	160.1	804.2	1479.4	627.6	3071.4
2020	1	COAL	-	-	-	-	-	-	-	18.6	77.2	173.9	180.5	58.3	508.5
2020	1	CCIG	-	-	-	-	-	-	-	-	-	26.9	160.5	86.6	274.0
2020	4	GTIG	-	-	-	-	-	-	-	-	-	-	54.7	119.4	174.1
2020	2	NUCL	-	-	-	-	-	-	40.3	99.9	308.2	528.5	352.8	98.3	1428.0
END		TOTAL	2544.8	2621.0	2953.3	3070.0	2994.4	3080.7	3465.8	3837.6	4165.9	4709.7	5432.4	4633.5	

FOREIGN CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	#	PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6	FOL6	-	-	137.2	689.3	1268.1	538.0	-	2632.6
2021	2	COAL	-	37.1	154.3	347.9	361.0	116.7	-	1017.0
2021	7	GTIG	-	-	-	-	95.6	209.0	-	304.6
2021	2	NUCL	40.3	99.9	308.2	528.5	352.8	98.3	-	1428.0
2022	6	FOL6	-	-	-	137.2	689.3	1268.1	538.0	2632.6
2022	2	COAL	-	-	37.1	154.3	347.9	361.0	116.7	1017.0
2022	10	GTIG	-	-	-	-	-	136.6	298.6	435.2
2022	2	NUCL	-	40.3	99.9	308.2	528.5	352.8	98.3	1428.0
END		TOTAL	3837.6	4165.9	4709.7	5432.4	4633.5	3080.5	1051.5	63134.8

DOMESTIC INT. DURING CONSTR. (MILLION $)

YEAR	# PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1 COAL	.3	1.9	6.3	12.8	18.1	-	-	-	-	-	-	-	39.4
2000	1 DCOL	-	.1	.6	1.8	3.1	-	-	-	-	-	-	-	5.6
2000	2 CCIG	-	-	.7	5.4	12.1	-	-	-	-	-	-	-	18.1
2001	1 DCOL	-	-	.1	.6	1.8	3.1	-	-	-	-	-	-	5.6
2001	2 CCIG	-	-	-	.7	5.4	12.1	-	-	-	-	-	-	18.1
2001	1 GTIG	-	-	-	-	.1	.5	-	-	-	-	-	-	.6
2002	1 DCOL	-	-	-	.1	.6	1.8	3.1	-	-	-	-	-	5.6
2003	1 DCOL	-	-	-	-	.1	.6	1.8	3.1	-	-	-	-	5.6
2003	2 CCIG	-	-	-	-	-	.7	5.4	12.1	-	-	-	-	18.1
2003	1 GTIG	-	-	-	-	-	-	.1	.5	-	-	-	-	.6
2003	1 NUCL	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	86.8
2003	1 JINH	-	-	-	-	.2	1.8	5.5	9.4	-	-	-	-	16.9
2004	1 COAL	-	-	-	-	.3	1.9	6.3	12.8	18.1	-	-	-	39.4
2004	1 DCOL	-	-	-	-	-	.1	.6	1.8	3.1	-	-	-	5.6
2004	2 CCIG	-	-	-	-	-	-	.7	5.4	12.1	-	-	-	18.1
2004	1 GTIG	-	-	-	-	-	-	-	.1	.5	-	-	-	.6
2005	1 DCOL	-	-	-	-	-	-	.1	.6	1.8	3.1	-	-	5.6
2005	2 CCIG	-	-	-	-	-	-	-	.7	5.4	12.1	-	-	18.1
2005	1 GTIG	-	-	-	-	-	-	-	-	.1	.5	-	-	.6
2005	1 NUCL	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	86.8
2005	1 TAUN	-	-	-	-	-	-	.2	1.1	3.5	6.0	-	-	10.9
2006	1 DCOL	-	-	-	-	-	-	-	.1	.6	1.8	3.1	-	5.6
2006	2 CCIG	-	-	-	-	-	-	-	-	.7	5.4	12.1	-	18.1
2006	2 GTIG	-	-	-	-	-	-	-	-	-	.2	1.0	-	1.3
2006	1 KBG1	-	-	-	-	-	1.0	4.6	15.4	38.1	64.3	82.3	-	205.7
2007	1 DCOL	-	-	-	-	-	-	-	-	.1	.6	1.8	3.1	5.6
2007	1 CCIG	-	-	-	-	-	-	-	-	-	.3	2.7	6.1	9.1
2007	1 NUCL	-	-	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	86.8
END TOTAL		.3	2.0	8.0	23.3	48.8	41.6	62.4	118.1	128.6	183.3	233.0	244.1	

DOMESTIC INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	# PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1 DCOL	-	-	.1	.6	1.8	3.1	-	-	-	-	-	-	5.6
2008	1 NUCL	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	-	-	86.8
2008	1 KBG2	1.0	4.6	15.4	38.1	64.3	82.3	-	-	-	-	-	-	205.7
2008	1 KOHA	.8	3.8	12.7	31.4	53.0	67.9	-	-	-	-	-	-	169.7
2009	1 DCOL	-	-	-	.1	.6	1.8	3.1	-	-	-	-	-	5.6
2009	1 CCIG	-	-	-	-	.3	2.7	6.1	-	-	-	-	-	9.1
2009	3 GTIG	-	-	-	-	-	.4	1.5	-	-	-	-	-	1.9
2009	1 NUCL	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	-	86.8
2009	1 TA16	-	-	1.1	6.7	22.0	44.9	63.5	-	-	-	-	-	138.2
2010	1 COAL	-	-	-	.3	1.9	6.3	12.8	18.1	-	-	-	-	39.4
2010	3 CCIG	-	-	-	-	-	1.0	8.0	18.2	-	-	-	-	27.2
2010	1 GTIG	-	-	-	-	-	-	.1	.5	-	-	-	-	.6
2010	1 NUCL	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	86.8
2011	1 COAL	-	-	-	-	.3	1.9	6.3	12.8	18.1	-	-	-	39.4
2011	1 CCIG	-	-	-	-	-	-	.3	2.7	6.1	-	-	-	9.1
2011	7 GTIG	-	-	-	-	-	-	-	.8	3.6	-	-	-	4.4
2011	1 NUCL	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	86.8
2011	1 BSH1	-	-	-	.7	3.1	10.2	25.2	42.5	54.5	-	-	-	136.1
2012	2 COAL	-	-	-	-	-	.6	3.8	12.5	25.6	36.2	-	-	78.7
2012	2 CCIG	-	-	-	-	-	-	-	.7	5.4	12.1	-	-	18.1
2012	4 GTIG	-	-	-	-	-	-	-	-	.5	2.0	-	-	2.5
2012	1 NUCL	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	86.8
2012	1 BSH2	-	-	-	-	.7	3.1	10.2	25.2	42.5	54.5	-	-	136.1
2013	2 COAL	-	-	-	-	-	-	.6	3.8	12.5	25.6	36.2	-	78.7
2013	3 CCIG	-	-	-	-	-	-	-	-	1.0	8.0	18.2	-	27.2
2013	6 GTIG	-	-	-	-	-	-	-	-	-	.7	3.1	-	3.8
2013	1 NUCL	-	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	86.8
2013	1 BSH3	-	-	-	-	-	.7	3.1	10.2	25.2	42.5	54.5	-	136.1
2014	2 COAL	-	-	-	-	-	-	-	.6	3.8	12.5	25.6	36.2	78.7
2014	3 CCIG	-	-	-	-	-	-	-	-	-	1.0	8.0	18.2	27.2
2014	2 GTIG	-	-	-	-	-	-	-	-	-	-	.2	1.0	1.3
2014	1 NUCL	-	-	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	86.8
END TOTAL		118.1	128.6	183.3	233.0	244.1	313.6	232.1	238.5	296.3	311.6	293.8	255.3	

DOMESTIC INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	#	PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1	BSH4	.7	3.1	10.2	25.2	42.5	54.5	-	-	-	-	-	-	136.1
2015	2	COAL	-	-	.6	3.8	12.5	25.6	36.2	-	-	-	-	-	78.7
2015	4	CCIG	-	-	-	-	1.3	10.7	24.2	-	-	-	-	-	36.2
2015	8	GTIG	-	-	-	-	-	.9	4.1	-	-	-	-	-	5.0
2015	1	NUCL	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	-	86.8
2016	1	FOL6	-	-	-	-	.4	2.7	8.4	14.2	-	-	-	-	25.7
2016	2	COAL	-	-	-	.6	3.8	12.5	25.6	36.2	-	-	-	-	78.7
2016	3	CCIG	-	-	-	-	-	1.0	8.0	18.2	-	-	-	-	27.2
2016	7	GTIG	-	-	-	-	-	-	.8	3.6	-	-	-	-	4.4
2016	1	NUCL	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	-	86.8
2017	1	FOL6	-	-	-	-	-	.4	2.7	8.4	14.2	-	-	-	25.7
2017	2	COAL	-	-	-	-	.6	3.8	12.5	25.6	36.2	-	-	-	78.7
2017	4	CCIG	-	-	-	-	-	-	1.3	10.7	24.2	-	-	-	36.2
2017	3	GTIG	-	-	-	-	-	-	-	.4	1.5	-	-	-	1.9
2017	1	NUCL	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	-	86.8
2018	3	FOL6	-	-	-	-	-	-	1.1	8.0	25.1	42.7	-	-	77.0
2018	2	COAL	-	-	-	-	-	.6	3.8	12.5	25.6	36.2	-	-	78.7
2018	3	CCIG	-	-	-	-	-	-	-	1.0	8.0	18.2	-	-	27.2
2018	1	NUCL	-	-	-	-	.4	2.0	6.5	16.1	27.1	34.7	-	-	86.8
2019	1	FOL6	-	-	-	-	-	-	-	.4	2.7	8.4	14.2	-	25.7
2019	2	COAL	-	-	-	-	-	-	.6	3.8	12.5	25.6	36.2	-	78.7
2019	4	CCIG	-	-	-	-	-	-	-	-	1.3	10.7	24.2	-	36.2
2019	13	GTIG	-	-	-	-	-	-	-	-	-	1.5	6.7	-	8.2
2019	2	NUCL	-	-	-	-	-	.8	3.9	13.0	32.1	54.3	69.5	-	173.6
2020	7	FOL6	-	-	-	-	-	-	-	-	2.6	18.8	58.5	99.7	179.7
2020	1	COAL	-	-	-	-	-	-	-	.3	1.9	6.3	12.8	18.1	39.4
2020	1	CCIG	-	-	-	-	-	-	-	-	-	.3	2.7	6.1	9.1
2020	4	GTIG	-	-	-	-	-	-	-	-	-	-	.5	2.0	2.5
2020	2	NUCL	-	-	-	-	-	-	.8	3.9	13.0	32.1	54.3	69.5	173.6
END		TOTAL	232.1	238.5	296.3	311.6	293.8	255.3	218.6	239.0	268.3	313.4	359.4	387.0	

DOMESTIC INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	#	PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6	FOL6	-	-	2.2	16.1	50.2	85.5	-	154.0
2021	2	COAL	-	.6	3.8	12.5	25.6	36.2	-	78.7
2021	7	GTIG	-	-	-	-	.8	3.6	-	4.4
2021	2	NUCL	.8	3.9	13.0	32.1	54.3	69.5	-	173.6
2022	6	FOL6	-	-	-	2.2	16.1	50.2	85.5	154.0
2022	2	COAL	-	-	.6	3.8	12.5	25.6	36.2	78.7
2022	10	GTIG	-	-	-	-	-	1.2	5.1	6.3
2022	2	NUCL	-	.8	3.9	13.0	32.1	54.3	69.5	173.6
END		TOTAL	239.0	268.3	313.4	359.4	387.0	326.0	196.3	5342.7

FOREIGN INT. DURING CONSTR. (MILLION $)

YEAR	#	PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1	COAL	.9	5.7	18.8	38.4	54.3	-	-	-	-	-	-	-	118.1
2000	1	DCOL	-	.3	2.4	7.4	12.5	-	-	-	-	-	-	-	22.6
2000	2	CCIG	-	-	2.6	21.4	48.4	-	-	-	-	-	-	-	72.5
2001	1	DCOL	-	-	.3	2.4	7.4	12.5	-	-	-	-	-	-	22.6
2001	2	CCIG	-	-	-	2.6	21.4	48.4	-	-	-	-	-	-	72.5
2001	1	GTIG	-	-	-	-	.7	2.9	-	-	-	-	-	-	3.6
2002	1	DCOL	-	-	-	.3	2.4	7.4	12.5	-	-	-	-	-	22.6
2003	1	DCOL	-	-	-	-	.3	2.4	7.4	12.5	-	-	-	-	22.6
2003	2	CCIG	-	-	-	-	-	2.6	21.4	48.4	-	-	-	-	72.5
2003	1	GTIG	-	-	-	-	-	-	.7	2.9	-	-	-	-	3.6
2003	1	NUCL	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	202.6
2003	1	JINH	-	-	-	-	.5	3.7	11.7	19.9	-	-	-	-	35.8
2004	1	COAL	-	-	-	-	.9	5.7	18.8	38.4	54.3	-	-	-	118.1
2004	1	DCOL	-	-	-	-	-	.3	2.4	7.4	12.5	-	-	-	22.6
2004	2	CCIG	-	-	-	-	-	-	2.6	21.4	48.4	-	-	-	72.5
2004	1	GTIG	-	-	-	-	-	-	-	.7	2.9	-	-	-	3.6
2005	1	DCOL	-	-	-	-	-	-	.3	2.4	7.4	12.5	-	-	22.6
2005	2	CCIG	-	-	-	-	-	-	-	2.6	21.4	48.4	-	-	72.5
2005	1	GTIG	-	-	-	-	-	-	-	-	.7	2.9	-	-	3.6
2005	1	NUCL	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	202.6
2005	1	TAUN	-	-	-	-	-	-	.4	3.0	9.3	15.9	-	-	28.6
2006	1	DCOL	-	-	-	-	-	-	-	.3	2.4	7.4	12.5	-	22.6
2006	2	CCIG	-	-	-	-	-	-	-	-	2.6	21.4	48.4	-	72.5
2006	2	GTIG	-	-	-	-	-	-	-	-	-	1.3	5.8	-	7.1
2006	1	KBG1	-	-	-	-	-	1.2	5.7	18.8	46.5	78.6	100.6	-	251.5
2007	1	DCOL	-	-	-	-	-	-	-	-	.3	2.4	7.4	12.5	22.6
2007	1	CCIG	-	-	-	-	-	-	-	-	-	1.3	10.7	24.2	36.2
2007	1	NUCL	-	-	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	202.6
END TOTAL			.9	6.1	25.1	77.1	164.9	129.3	163.3	305.0	303.1	368.5	412.0	456.4	

FOREIGN INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	#	PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1	DCOL	-	-	.3	2.4	7.4	12.5	-	-	-	-	-	-	22.6
2008	1	NUCL	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	-	-	202.6
2008	1	KBG2	1.2	5.7	18.8	46.5	78.6	100.6	-	-	-	-	-	-	251.5
2008	1	KOHA	1.0	4.7	15.5	38.4	64.8	83.0	-	-	-	-	-	-	207.4
2009	1	DCOL	-	-	-	.3	2.4	7.4	12.5	-	-	-	-	-	22.6
2009	1	CCIG	-	-	-	-	1.3	10.7	24.2	-	-	-	-	-	36.2
2009	3	GTIG	-	-	-	-	-	2.0	8.7	-	-	-	-	-	10.7
2009	1	NUCL	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	-	202.6
2009	1	TA16	-	-	2.5	15.7	51.3	104.8	148.2	-	-	-	-	-	322.5
2010	1	COAL	-	-	-	.9	5.7	18.8	38.4	54.3	-	-	-	-	118.1
2010	3	CCIG	-	-	-	-	-	4.0	32.1	72.6	-	-	-	-	108.7
2010	1	GTIG	-	-	-	-	-	-	.7	2.9	-	-	-	-	3.6
2010	1	NUCL	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	202.6
2011	1	COAL	-	-	-	-	.9	5.7	18.8	38.4	54.3	-	-	-	118.1
2011	1	CCIG	-	-	-	-	-	-	1.3	10.7	24.2	-	-	-	36.2
2011	7	GTIG	-	-	-	-	-	-	-	4.7	20.3	-	-	-	25.0
2011	1	NUCL	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	202.6
2011	1	BSH1	-	-	-	.8	3.8	12.4	30.8	52.0	66.6	-	-	-	166.3
2012	2	COAL	-	-	-	-	-	1.8	11.5	37.6	76.8	108.5	-	-	236.2
2012	2	CCIG	-	-	-	-	-	-	-	2.6	21.4	48.4	-	-	72.5
2012	4	GTIG	-	-	-	-	-	-	-	-	2.7	11.6	-	-	14.3
2012	1	NUCL	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	202.6
2012	1	BSH2	-	-	-	-	.8	3.8	12.4	30.8	52.0	66.6	-	-	166.3
2013	2	COAL	-	-	-	-	-	-	1.8	11.5	37.6	76.8	108.5	-	236.2
2013	3	CCIG	-	-	-	-	-	-	-	-	4.0	32.1	72.6	-	108.7
2013	6	GTIG	-	-	-	-	-	-	-	-	-	4.0	17.4	-	21.4
2013	1	NUCL	-	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	202.6
2013	1	BSH3	-	-	-	-	-	.8	3.8	12.4	30.8	52.0	66.6	-	166.3
2014	2	COAL	-	-	-	-	-	-	-	1.8	11.5	37.6	76.8	108.5	236.2
2014	3	CCIG	-	-	-	-	-	-	-	-	-	4.0	32.1	72.6	108.7
2014	2	GTIG	-	-	-	-	-	-	-	-	-	-	1.3	5.8	7.1
2014	1	NUCL	-	-	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	202.6
END TOTAL			305.0	303.1	368.5	412.0	456.4	570.9	548.6	538.7	618.9	688.3	687.3	646.1	

FOREIGN INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	# PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1 BSH4	.8	3.8	12.4	30.8	52.0	66.6	-	-	-	-	-	-	166.3
2015	2 COAL	-	-	1.8	11.5	37.6	76.8	108.5	-	-	-	-	-	236.2
2015	4 CCIG	-	-	-	-	5.3	42.9	96.8	-	-	-	-	-	145.0
2015	8 GTIG	-	-	-	-	-	5.4	23.2	-	-	-	-	-	28.6
2015	1 NUCL	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	-	202.6
2016	1 FOL6	-	-	-	-	1.1	8.0	25.1	42.7	-	-	-	-	77.0
2016	2 COAL	-	-	-	1.8	11.5	37.6	76.8	108.5	-	-	-	-	236.2
2016	3 CCIG	-	-	-	-	-	4.0	32.1	72.6	-	-	-	-	108.7
2016	7 GTIG	-	-	-	-	-	-	4.7	20.3	-	-	-	-	25.0
2016	1 NUCL	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	-	202.6
2017	1 FOL6	-	-	-	-	-	1.1	8.0	25.1	42.7	-	-	-	77.0
2017	2 COAL	-	-	-	-	1.8	11.5	37.6	76.8	108.5	-	-	-	236.2
2017	4 CCIG	-	-	-	-	-	-	5.3	42.9	96.8	-	-	-	145.0
2017	3 GTIG	-	-	-	-	-	-	-	2.0	8.7	-	-	-	10.7
2017	1 NUCL	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	-	202.6
2018	3 FOL6	-	-	-	-	-	-	3.4	24.1	75.3	128.2	-	-	231.0
2018	2 COAL	-	-	-	-	-	1.8	11.5	37.6	76.8	108.5	-	-	236.2
2018	3 CCIG	-	-	-	-	-	-	-	4.0	32.1	72.6	-	-	108.7
2018	1 NUCL	-	-	-	-	1.0	4.6	15.1	37.5	63.3	81.1	-	-	202.6
2019	1 FOL6	-	-	-	-	-	-	-	1.1	8.0	25.1	42.7	-	77.0
2019	2 COAL	-	-	-	-	-	-	1.8	11.5	37.6	76.8	108.5	-	236.2
2019	4 CCIG	-	-	-	-	-	-	-	-	5.3	42.9	96.8	-	145.0
2019	13 GTIG	-	-	-	-	-	-	-	-	-	8.7	37.7	-	46.5
2019	2 NUCL	-	-	-	-	-	2.0	9.1	30.3	75.0	126.7	162.1	-	405.2
2020	7 FOL6	-	-	-	-	-	-	-	-	7.9	56.3	175.6	299.2	539.1
2020	1 COAL	-	-	-	-	-	-	-	.9	5.7	18.8	38.4	54.3	118.1
2020	1 CCIG	-	-	-	-	-	-	-	-	-	1.3	10.7	24.2	36.2
2020	4 GTIG	-	-	-	-	-	-	-	-	-	-	2.7	11.6	14.3
2020	2 NUCL	-	-	-	-	-	-	2.0	9.1	30.3	75.0	126.7	162.1	405.2
END TOTAL		548.6	538.7	618.9	688.3	687.3	646.1	643.0	693.4	768.1	881.5	1011.4	1070.9	

FOREIGN INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	# PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6 FOL6	-	-	6.7	48.3	150.5	256.5	-	462.1
2021	2 COAL	-	1.8	11.5	37.6	76.8	108.5	-	236.2
2021	7 GTIG	-	-	-	-	4.7	20.3	-	25.0
2021	2 NUCL	2.0	9.1	30.3	75.0	126.7	162.1	-	405.2
2022	6 FOL6	-	-	-	6.7	48.3	150.5	256.5	462.1
2022	2 COAL	-	-	1.8	11.5	37.6	76.8	108.5	236.2
2022	10 GTIG	-	-	-	-	-	6.7	29.0	35.7
2022	2 NUCL	-	2.0	9.1	30.3	75.0	126.7	162.1	405.2
END TOTAL		693.4	768.1	881.5	1011.4	1070.9	908.1	556.1	13243.2

DOMESTIC CONSTRUCTION & IDC (MILLION $)

YEAR	# PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1 COAL	6.5	27.6	64.2	73.0	37.5	-	-	-	-	-	-	-	208.9
2000	1 DCOL	-	1.8	9.0	17.3	9.7	-	-	-	-	-	-	-	37.8
2000	2 CCIG	-	-	14.1	85.6	55.4	-	-	-	-	-	-	-	155.1
2001	1 DCOL	-	-	1.8	9.0	17.3	9.7	-	-	-	-	-	-	37.8
2001	2 CCIG	-	-	-	14.1	85.6	55.4	-	-	-	-	-	-	155.1
2001	1 GTIG	-	-	-	-	2.5	5.8	-	-	-	-	-	-	8.3
2002	1 DCOL	-	-	-	1.8	9.0	17.3	9.7	-	-	-	-	-	37.8
2003	1 DCOL	-	-	-	-	1.8	9.0	17.3	9.7	-	-	-	-	37.8
2003	2 CCIG	-	-	-	-	-	14.1	85.6	55.4	-	-	-	-	155.1
2003	1 GTIG	-	-	-	-	-	-	2.5	5.8	-	-	-	-	8.3
2003	1 NUCL	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	392.8
2003	1 JINH	-	-	-	-	5.3	26.9	51.8	29.0	-	-	-	-	112.9
2004	1 COAL	-	-	-	-	6.5	27.6	64.2	73.0	37.5	-	-	-	208.9
2004	1 DCOL	-	-	-	-	-	1.8	9.0	17.3	9.7	-	-	-	37.8
2004	2 CCIG	-	-	-	-	-	-	14.1	85.6	55.4	-	-	-	155.1
2004	1 GTIG	-	-	-	-	-	-	-	2.5	5.8	-	-	-	8.3
2005	1 DCOL	-	-	-	-	-	-	1.8	9.0	17.3	9.7	-	-	37.8
2005	2 CCIG	-	-	-	-	-	-	-	14.1	85.6	55.4	-	-	155.1
2005	1 GTIG	-	-	-	-	-	-	-	-	2.5	5.8	-	-	8.3
2005	1 NUCL	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	392.8
2005	1 TAUN	-	-	-	-	-	-	3.4	17.3	33.3	18.7	-	-	72.7
2006	1 DCOL	-	-	-	-	-	-	-	1.8	9.0	17.3	9.7	-	37.8
2006	2 CCIG	-	-	-	-	-	-	-	-	14.1	85.6	55.4	-	155.1
2006	2 GTIG	-	-	-	-	-	-	-	-	-	5.1	11.6	-	16.6
2006	1 KBG1	-	-	-	-	-	21.5	55.4	171.9	306.5	243.5	132.3	-	930.9
2007	1 DCOL	-	-	-	-	-	-	-	-	1.8	9.0	17.3	9.7	37.8
2007	1 CCIG	-	-	-	-	-	-	-	-	-	7.1	42.8	27.7	77.6
2007	1 NUCL	-	-	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	392.8
END	TOTAL	6.5	29.4	98.2	224.2	312.2	341.8	499.1	749.1	887.3	1085.4	1293.7	1218.4	

DOMESTIC CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	# PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1 DCOL	-	-	1.8	9.0	17.3	9.7	-	-	-	-	-	-	37.8
2008	1 NUCL	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	-	-	392.8
2008	1 KBG2	21.5	55.4	171.9	306.5	243.5	132.3	-	-	-	-	-	-	930.9
2008	1 KOHA	17.7	45.7	141.7	252.7	200.8	109.1	-	-	-	-	-	-	767.7
2009	1 DCOL	-	-	-	1.8	9.0	17.3	9.7	-	-	-	-	-	37.8
2009	1 CCIG	-	-	-	-	7.1	42.8	27.7	-	-	-	-	-	77.6
2009	3 GTIG	-	-	-	-	-	7.6	17.3	-	-	-	-	-	24.9
2009	1 NUCL	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	-	392.8
2009	1 TA16	-	-	22.8	97.0	225.6	256.2	131.8	-	-	-	-	-	733.4
2010	1 COAL	-	-	-	6.5	27.6	64.2	73.0	37.5	-	-	-	-	208.9
2010	3 CCIG	-	-	-	-	-	21.2	128.4	83.1	-	-	-	-	232.7
2010	1 GTIG	-	-	-	-	-	-	2.5	5.8	-	-	-	-	8.3
2010	1 NUCL	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	392.8
2011	1 COAL	-	-	-	-	6.5	27.6	64.2	73.0	37.5	-	-	-	208.9
2011	1 CCIG	-	-	-	-	-	-	7.1	42.8	27.7	-	-	-	77.6
2011	7 GTIG	-	-	-	-	-	-	-	17.7	40.5	-	-	-	58.2
2011	1 NUCL	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	392.8
2011	1 BSH1	-	-	-	14.2	36.6	113.7	202.7	161.1	87.5	-	-	-	615.7
2012	2 COAL	-	-	-	-	-	13.0	55.3	128.5	145.9	75.1	-	-	417.7
2012	2 CCIG	-	-	-	-	-	-	-	14.1	85.6	55.4	-	-	155.1
2012	4 GTIG	-	-	-	-	-	-	-	-	10.1	23.1	-	-	33.2
2012	1 NUCL	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	392.8
2012	1 BSH2	-	-	-	-	14.2	36.6	113.7	202.7	161.1	87.5	-	-	615.7
2013	2 COAL	-	-	-	-	-	-	13.0	55.3	128.5	145.9	75.1	-	417.7
2013	3 CCIG	-	-	-	-	-	-	-	-	21.2	128.4	83.1	-	232.7
2013	6 GTIG	-	-	-	-	-	-	-	-	-	15.2	34.7	-	49.9
2013	1 NUCL	-	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	392.8
2013	1 BSH3	-	-	-	-	-	14.2	36.6	113.7	202.7	161.1	87.5	-	615.7
2014	2 COAL	-	-	-	-	-	-	-	13.0	55.3	128.5	145.9	75.1	417.7
2014	3 CCIG	-	-	-	-	-	-	-	-	-	21.2	128.4	83.1	232.7
2014	2 GTIG	-	-	-	-	-	-	-	-	-	-	5.1	11.6	16.6
2014	1 NUCL	-	-	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	392.8
END	TOTAL	749.1	887.3	1085.4	1293.7	1218.4	1258.3	1290.1	1377.6	1523.0	1505.1	1346.6	1263.3	

DOMESTIC CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	#	PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1	BSH4	14.2	36.6	113.7	202.7	161.1	87.5	-	-	-	-	-	-	615.7
2015	2	COAL	-	-	13.0	55.3	128.5	145.9	75.1	-	-	-	-	-	417.7
2015	4	CCIG	-	-	-	-	28.2	171.3	110.8	-	-	-	-	-	310.2
2015	8	GTIG	-	-	-	-	-	20.2	46.2	-	-	-	-	-	66.5
2015	1	NUCL	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	-	392.8
2016	1	FOL6	-	-	-	-	8.0	41.0	78.8	44.1	-	-	-	-	171.9
2016	2	COAL	-	-	-	13.0	55.3	128.5	145.9	75.1	-	-	-	-	417.7
2016	3	CCIG	-	-	-	-	-	21.2	128.4	83.1	-	-	-	-	232.7
2016	7	GTIG	-	-	-	-	-	-	17.7	40.5	-	-	-	-	58.2
2016	1	NUCL	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	-	392.8
2017	1	FOL6	-	-	-	-	-	8.0	41.0	78.8	44.1	-	-	-	171.9
2017	2	COAL	-	-	-	-	13.0	55.3	128.5	145.9	75.1	-	-	-	417.7
2017	4	CCIG	-	-	-	-	-	-	28.2	171.3	110.8	-	-	-	310.2
2017	3	GTIG	-	-	-	-	-	-	-	7.6	17.3	-	-	-	24.9
2017	1	NUCL	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	-	392.8
2018	3	FOL6	-	-	-	-	-	-	24.0	122.9	236.4	132.4	-	-	515.8
2018	2	COAL	-	-	-	-	-	13.0	55.3	128.5	145.9	75.1	-	-	417.7
2018	3	CCIG	-	-	-	-	-	-	-	21.2	128.4	83.1	-	-	232.7
2018	1	NUCL	-	-	-	-	9.1	23.4	72.5	129.3	102.7	55.8	-	-	392.8
2019	1	FOL6	-	-	-	-	-	-	-	8.0	41.0	78.8	44.1	-	171.9
2019	2	COAL	-	-	-	-	-	-	13.0	55.3	128.5	145.9	75.1	-	417.7
2019	4	CCIG	-	-	-	-	-	-	-	-	28.2	171.3	110.8	-	310.2
2019	13	GTIG	-	-	-	-	-	-	-	-	-	32.9	75.2	-	108.0
2019	2	NUCL	-	-	-	-	-	18.1	46.7	145.1	258.6	205.5	111.6	-	785.6
2020	7	FOL6	-	-	-	-	-	-	-	-	56.0	286.9	551.7	309.0	1203.5
2020	1	COAL	-	-	-	-	-	-	-	6.5	27.6	64.2	73.0	37.5	208.9
2020	1	CCIG	-	-	-	-	-	-	-	-	-	7.1	42.8	27.7	77.6
2020	4	GTIG	-	-	-	-	-	-	-	-	-	-	10.1	23.1	33.2
2020	2	NUCL	-	-	-	-	-	-	18.1	46.7	145.1	258.6	205.5	111.6	785.6
END	TOTAL		1290.1	1377.6	1523.0	1505.1	1346.6	1263.3	1318.1	1486.4	1679.5	1905.6	2181.1	1983.9	

DOMESTIC CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	#	PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6	FOL6	-	-	48.0	245.9	472.9	264.8	-	1031.6
2021	2	COAL	-	13.0	55.3	128.5	145.9	75.1	-	417.7
2021	7	GTIG	-	-	-	-	17.7	40.5	-	58.2
2021	2	NUCL	18.1	46.7	145.1	258.6	205.5	111.6	-	785.6
2022	6	FOL6	-	-	-	48.0	245.9	472.9	264.8	1031.6
2022	2	COAL	-	-	13.0	55.3	128.5	145.9	75.1	417.7
2022	10	GTIG	-	-	-	-	-	25.3	57.8	83.1
2022	2	NUCL	-	18.1	46.7	145.1	258.6	205.5	111.6	785.6
END	TOTAL		1486.4	1679.5	1905.6	2181.1	1983.9	1341.6	509.3	28714.7

FOREIGN CONSTRUCTION & IDC (MILLION $)

YEAR	# PLANT	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	SUM
2000	1 COAL	19.5	82.9	192.7	218.9	112.6	-	-	-	-	-	-	-	626.6
2000	1 DCOL	-	7.0	36.0	69.3	38.8	-	-	-	-	-	-	-	151.2
2000	2 CCIG	-	-	56.4	342.5	221.5	-	-	-	-	-	-	-	620.4
2001	1 DCOL	-	-	7.0	36.0	69.3	38.8	-	-	-	-	-	-	151.2
2001	2 CCIG	-	-	-	56.4	342.5	221.5	-	-	-	-	-	-	620.4
2001	1 GTIG	-	-	-	-	14.3	32.8	-	-	-	-	-	-	47.1
2002	1 DCOL	-	-	-	7.0	36.0	69.3	38.8	-	-	-	-	-	151.2
2003	1 DCOL	-	-	-	-	7.0	36.0	69.3	38.8	-	-	-	-	151.2
2003	2 CCIG	-	-	-	-	-	56.4	342.5	221.5	-	-	-	-	620.4
2003	1 GTIG	-	-	-	-	-	-	14.3	32.8	-	-	-	-	47.1
2003	1 NUCL	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	916.6
2003	1 JINH	-	-	-	-	11.2	57.2	110.0	61.6	-	-	-	-	239.9
2004	1 COAL	-	-	-	-	19.5	82.9	192.7	218.9	112.6	-	-	-	626.6
2004	1 DCOL	-	-	-	-	-	7.0	36.0	69.3	38.8	-	-	-	151.2
2004	2 CCIG	-	-	-	-	-	-	56.4	342.5	221.5	-	-	-	620.4
2004	1 GTIG	-	-	-	-	-	-	-	14.3	32.8	-	-	-	47.1
2005	1 DCOL	-	-	-	-	-	-	7.0	36.0	69.3	38.8	-	-	151.2
2005	2 CCIG	-	-	-	-	-	-	-	56.4	342.5	221.5	-	-	620.4
2005	1 GTIG	-	-	-	-	-	-	-	-	14.3	32.8	-	-	47.1
2005	1 NUCL	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	916.6
2005	1 TAUN	-	-	-	-	-	-	8.9	45.7	87.9	49.2	-	-	191.8
2006	1 DCOL	-	-	-	-	-	-	-	7.0	36.0	69.3	38.8	-	151.2
2006	2 CCIG	-	-	-	-	-	-	-	-	56.4	342.5	221.5	-	620.4
2006	2 GTIG	-	-	-	-	-	-	-	-	-	28.7	65.5	-	94.2
2006	1 KBG1	-	-	-	-	-	26.2	67.7	210.1	374.6	297.6	161.6	-	1137.8
2007	1 DCOL	-	-	-	-	-	-	-	-	7.0	36.0	69.3	38.8	151.2
2007	1 CCIG	-	-	-	-	-	-	-	-	-	28.2	171.2	110.8	310.2
2007	1 NUCL	-	-	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	916.6
END	TOTAL	19.5	89.9	313.3	784.7	1063.2	984.5	1373.9	1910.5	2001.9	2265.1	2504.2	2433.6	

FOREIGN CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	# PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM
2008	1 DCOL	-	-	7.0	36.0	69.3	38.8	-	-	-	-	-	-	151.2
2008	1 NUCL	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	-	-	916.6
2008	1 KBG2	26.2	67.7	210.1	374.6	297.6	161.6	-	-	-	-	-	-	1137.8
2008	1 KOHA	21.6	55.8	173.2	308.9	245.4	133.3	-	-	-	-	-	-	938.3
2009	1 DCOL	-	-	-	7.0	36.0	69.3	38.8	-	-	-	-	-	151.2
2009	1 CCIG	-	-	-	-	28.2	171.2	110.8	-	-	-	-	-	310.2
2009	3 GTIG	-	-	-	-	-	43.0	98.3	-	-	-	-	-	141.3
2009	1 NUCL	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	-	916.6
2009	1 TA16	-	-	53.2	226.4	526.3	597.8	307.5	-	-	-	-	-	1711.2
2010	1 COAL	-	-	-	19.5	82.9	192.7	218.9	112.6	-	-	-	-	626.6
2010	3 CCIG	-	-	-	-	-	84.6	513.7	332.3	-	-	-	-	930.7
2010	1 GTIG	-	-	-	-	-	-	14.3	32.8	-	-	-	-	47.1
2010	1 NUCL	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	916.6
2011	1 COAL	-	-	-	-	19.5	82.9	192.7	218.9	112.6	-	-	-	626.6
2011	1 CCIG	-	-	-	-	-	-	28.2	171.2	110.8	-	-	-	310.2
2011	7 GTIG	-	-	-	-	-	-	-	100.3	229.3	-	-	-	329.7
2011	1 NUCL	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	916.6
2011	1 BSH1	-	-	-	17.3	44.8	139.0	247.8	196.9	106.9	-	-	-	752.6
2012	2 COAL	-	-	-	-	-	38.9	165.8	385.4	437.8	225.2	-	-	1253.2
2012	2 CCIG	-	-	-	-	-	-	-	56.4	342.5	221.5	-	-	620.4
2012	4 GTIG	-	-	-	-	-	-	-	-	57.3	131.0	-	-	188.4
2012	1 NUCL	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	916.6
2012	1 BSH2	-	-	-	-	17.3	44.8	139.0	247.8	196.9	106.9	-	-	752.6
2013	2 COAL	-	-	-	-	-	-	38.9	165.8	385.4	437.8	225.2	-	1253.2
2013	3 CCIG	-	-	-	-	-	-	-	-	84.6	513.7	332.3	-	930.7
2013	6 GTIG	-	-	-	-	-	-	-	-	-	86.0	196.5	-	282.6
2013	1 NUCL	-	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	916.6
2013	1 BSH3	-	-	-	-	-	17.3	44.8	139.0	247.8	196.9	106.9	-	752.6
2014	2 COAL	-	-	-	-	-	-	-	38.9	165.8	385.4	437.8	225.2	1253.2
2014	3 CCIG	-	-	-	-	-	-	-	-	-	84.6	513.7	332.3	930.7
2014	2 GTIG	-	-	-	-	-	-	-	-	-	-	28.7	65.5	94.2
2014	1 NUCL	-	-	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	916.6
END	TOTAL	1910.5	2001.9	2265.1	2504.2	2433.6	2732.0	3093.5	3159.7	3572.2	3758.3	3681.6	3726.9	

FOREIGN CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	#	PLANT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	SUM
2014	1	BSH4	17.3	44.8	139.0	247.8	196.9	106.9	-	-	-	-	-	-	752.6
2015	2	COAL	-	-	38.9	165.8	385.4	437.8	225.2	-	-	-	-	-	1253.2
2015	4	CCIG	-	-	-	-	112.8	685.0	443.0	-	-	-	-	-	1240.9
2015	8	GTIG	-	-	-	-	-	114.7	262.1	-	-	-	-	-	376.7
2015	1	NUCL	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	-	916.6
2016	1	FOL6	-	-	-	-	24.0	122.9	236.4	132.4	-	-	-	-	515.8
2016	2	COAL	-	-	-	38.9	165.8	385.4	437.8	225.2	-	-	-	-	1253.2
2016	3	CCIG	-	-	-	-	-	84.6	513.7	332.3	-	-	-	-	930.7
2016	7	GTIG	-	-	-	-	-	-	100.3	229.3	-	-	-	-	329.7
2016	1	NUCL	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	-	916.6
2017	1	FOL6	-	-	-	-	-	24.0	122.9	236.4	132.4	-	-	-	515.8
2017	2	COAL	-	-	-	-	38.9	165.8	385.4	437.8	225.2	-	-	-	1253.2
2017	4	CCIG	-	-	-	-	-	-	112.8	685.0	443.0	-	-	-	1240.9
2017	3	GTIG	-	-	-	-	-	-	-	43.0	98.3	-	-	-	141.3
2017	1	NUCL	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	-	916.6
2018	3	FOL6	-	-	-	-	-	-	72.0	368.8	709.3	397.2	-	-	1547.3
2018	2	COAL	-	-	-	-	-	38.9	165.8	385.4	437.8	225.2	-	-	1253.2
2018	3	CCIG	-	-	-	-	-	-	-	84.6	513.7	332.3	-	-	930.7
2018	1	NUCL	-	-	-	-	21.1	54.5	169.2	301.7	239.7	130.2	-	-	916.6
2019	1	FOL6	-	-	-	-	-	-	-	24.0	122.9	236.4	132.4	-	515.8
2019	2	COAL	-	-	-	-	-	-	38.9	165.8	385.4	437.8	225.2	-	1253.2
2019	4	CCIG	-	-	-	-	-	-	-	-	112.8	685.0	443.0	-	1240.9
2019	13	GTIG	-	-	-	-	-	-	-	-	-	186.4	425.9	-	612.2
2019	2	NUCL	-	-	-	-	-	42.2	109.0	338.5	603.5	479.5	260.4	-	1833.2
2020	7	FOL6	-	-	-	-	-	-	-	-	168.0	860.6	1655.1	926.8	3610.4
2020	1	COAL	-	-	-	-	-	-	-	19.5	82.9	192.7	218.9	112.6	626.6
2020	1	CCIG	-	-	-	-	-	-	-	-	-	28.2	171.2	110.8	310.2
2020	4	GTIG	-	-	-	-	-	-	-	-	-	-	57.3	131.0	188.4
2020	2	NUCL	-	-	-	-	-	-	42.2	109.0	338.5	603.5	479.5	260.4	1833.2
END TOTAL			3093.5	3159.7	3572.2	3758.3	3681.6	3726.9	4108.8	4531.1	4934.0	5591.2	6443.8	5704.5	

FOREIGN CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	#	PLANT	2015	2016	2017	2018	2019	2020	2021	SUM
2021	6	FOL6	-	-	144.0	737.6	1418.6	794.4	-	3094.6
2021	2	COAL	-	38.9	165.8	385.4	437.8	225.2	-	1253.2
2021	7	GTIG	-	-	-	-	100.3	229.3	-	329.7
2021	2	NUCL	42.2	109.0	338.5	603.5	479.5	260.4	-	1833.2
2022	6	FOL6	-	-	-	144.0	737.6	1418.6	794.4	3094.6
2022	2	COAL	-	-	38.9	165.8	385.4	437.8	225.2	1253.2
2022	10	GTIG	-	-	-	-	-	143.4	327.6	470.9
2022	2	NUCL	-	42.2	109.0	338.5	603.5	479.5	260.4	1833.2
END TOTAL			4531.1	4934.0	5591.2	6443.8	5704.5	3988.7	1607.7	76378.0

DOMESTIC FUEL INVESTMENT (MILLION $)

YEAR	#	PLANT	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	SUM
2000	1	DCOL	.4	3.6	-	-	-	-	-	-	-	-	-	-	4.0
2001	1	DCOL	-	.4	3.6	-	-	-	-	-	-	-	-	-	4.0
2002	1	DCOL	-	-	.4	3.6	-	-	-	-	-	-	-	-	4.0
2003	1	DCOL	-	-	-	.4	3.6	-	-	-	-	-	-	-	4.0
2004	1	DCOL	-	-	-	-	.4	3.6	-	-	-	-	-	-	4.0
2005	1	DCOL	-	-	-	-	-	.4	3.6	-	-	-	-	-	4.0
2006	1	DCOL	-	-	-	-	-	-	.4	3.6	-	-	-	-	4.0
2007	1	DCOL	-	-	-	-	-	-	-	.4	3.6	-	-	-	4.0
2008	1	DCOL	-	-	-	-	-	-	-	-	.4	3.6	-	-	4.0
2009	1	DCOL	-	-	-	-	-	-	-	-	-	.4	3.6	-	4.0
END TOTAL			.4	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	3.6	.0	40.1

FOREIGN FUEL INVESTMENT (MILLION $)

YEAR	# PLANT	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	SUM
2000	1 COAL	3.0	27.5	-	-	-	-	-	-	-	-	-	-	30.5
2000	2 CCIG	1.6	15.1	-	-	-	-	-	-	-	-	-	-	16.7
2001	2 CCIG	-	1.6	15.1	-	-	-	-	-	-	-	-	-	16.7
2001	1 GTIG	-	.3	2.5	-	-	-	-	-	-	-	-	-	2.8
2003	2 CCIG	-	-	-	1.6	15.1	-	-	-	-	-	-	-	16.7
2003	1 GTIG	-	-	-	.3	2.5	-	-	-	-	-	-	-	2.8
2003	1 NUCL	-	-	-	5.3	48.7	-	-	-	-	-	-	-	54.0
2004	1 COAL	-	-	-	-	3.0	27.5	-	-	-	-	-	-	30.5
2004	2 CCIG	-	-	-	-	1.6	15.1	-	-	-	-	-	-	16.7
2004	1 GTIG	-	-	-	-	.3	2.5	-	-	-	-	-	-	2.8
2005	2 CCIG	-	-	-	-	-	1.6	15.1	-	-	-	-	-	16.7
2005	1 GTIG	-	-	-	-	-	.3	2.5	-	-	-	-	-	2.8
2005	1 NUCL	-	-	-	-	-	5.3	48.7	-	-	-	-	-	54.0
2006	2 CCIG	-	-	-	-	-	-	1.6	15.1	-	-	-	-	16.7
2006	2 GTIG	-	-	-	-	-	-	.6	5.1	-	-	-	-	5.6
2007	1 CCIG	-	-	-	-	-	-	-	.8	7.5	-	-	-	8.4
2007	1 NUCL	-	-	-	-	-	-	-	5.3	48.7	-	-	-	54.0
2008	1 NUCL	-	-	-	-	-	-	-	-	5.3	48.7	-	-	54.0
2009	1 CCIG	-	-	-	-	-	-	-	-	-	.8	7.5	-	8.4
2009	3 GTIG	-	-	-	-	-	-	-	-	-	.8	7.6	-	8.4
2009	1 NUCL	-	-	-	-	-	-	-	-	-	5.3	48.7	-	54.0
2010	1 COAL	-	-	-	-	-	-	-	-	-	-	3.0	27.5	30.5
2010	3 CCIG	-	-	-	-	-	-	-	-	-	-	2.5	22.6	25.1
2010	1 GTIG	-	-	-	-	-	-	-	-	-	-	.3	2.5	2.8
2010	1 NUCL	-	-	-	-	-	-	-	-	-	-	5.3	48.7	54.0
END TOTAL		4.6	44.5	17.6	7.2	71.2	52.3	68.5	26.3	61.5	55.6	74.9	112.4	

FOREIGN FUEL INVESTMENT (MILLION $) (CONTD.)

YEAR	# PLANT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	SUM
2011	1 COAL	3.0	27.5	-	-	-	-	-	-	-	-	-	-	30.5
2011	1 CCIG	.8	7.5	-	-	-	-	-	-	-	-	-	-	8.4
2011	7 GTIG	1.9	17.8	-	-	-	-	-	-	-	-	-	-	19.7
2011	1 NUCL	5.3	48.7	-	-	-	-	-	-	-	-	-	-	54.0
2012	2 COAL	-	6.0	55.1	-	-	-	-	-	-	-	-	-	61.1
2012	2 CCIG	-	1.6	15.1	-	-	-	-	-	-	-	-	-	16.7
2012	4 GTIG	-	1.1	10.1	-	-	-	-	-	-	-	-	-	11.3
2012	1 NUCL	-	5.3	48.7	-	-	-	-	-	-	-	-	-	54.0
2013	2 COAL	-	-	6.0	55.1	-	-	-	-	-	-	-	-	61.1
2013	3 CCIG	-	-	2.5	22.6	-	-	-	-	-	-	-	-	25.1
2013	6 GTIG	-	-	1.7	15.2	-	-	-	-	-	-	-	-	16.9
2013	1 NUCL	-	-	5.3	48.7	-	-	-	-	-	-	-	-	54.0
2014	2 COAL	-	-	-	6.0	55.1	-	-	-	-	-	-	-	61.1
2014	3 CCIG	-	-	-	2.5	22.6	-	-	-	-	-	-	-	25.1
2014	2 GTIG	-	-	-	.6	5.1	-	-	-	-	-	-	-	5.6
2014	1 NUCL	-	-	-	5.3	48.7	-	-	-	-	-	-	-	54.0
2015	2 COAL	-	-	-	-	6.0	55.1	-	-	-	-	-	-	61.1
2015	4 CCIG	-	-	-	-	3.3	30.1	-	-	-	-	-	-	33.4
2015	8 GTIG	-	-	-	-	2.2	20.3	-	-	-	-	-	-	22.5
2015	1 NUCL	-	-	-	-	5.3	48.7	-	-	-	-	-	-	54.0
2016	1 FOL6	-	-	-	-	-	1.3	12.0	-	-	-	-	-	13.4
2016	2 COAL	-	-	-	-	-	6.0	55.1	-	-	-	-	-	61.1
2016	3 CCIG	-	-	-	-	-	2.5	22.6	-	-	-	-	-	25.1
2016	7 GTIG	-	-	-	-	-	1.9	17.8	-	-	-	-	-	19.7
2016	1 NUCL	-	-	-	-	-	5.3	48.7	-	-	-	-	-	54.0
2017	1 FOL6	-	-	-	-	-	-	1.3	12.0	-	-	-	-	13.4
2017	2 COAL	-	-	-	-	-	-	6.0	55.1	-	-	-	-	61.1
2017	4 CCIG	-	-	-	-	-	-	3.3	30.1	-	-	-	-	33.4
2017	3 GTIG	-	-	-	-	-	-	.8	7.6	-	-	-	-	8.4
2017	1 NUCL	-	-	-	-	-	-	5.3	48.7	-	-	-	-	54.0
2018	3 FOL6	-	-	-	-	-	-	-	3.9	36.1	-	-	-	40.0
2018	2 COAL	-	-	-	-	-	-	-	6.0	55.1	-	-	-	61.1
END TOTAL		112.4	115.6	144.4	155.9	148.2	171.2	172.9	171.2	187.3	252.3	253.3	269.7	

FOREIGN FUEL INVESTMENT (MILLION $) (CONTD)

YEAR	#	PLANT	2016	2017	2018	2019	2020	2021	SUM
2018	3	CCIG	2 5	22 6	-	-	-		25 1
2018	1	NUCL	5 3	48 7	-	-	-		54 0
2019	1	FOL6	-	1 3	12 0	-	-	-	13 4
2019	2	COAL	-	6 0	55 1	-	-	-	61 1
2019	4	CCIG	-	3 3	30 1		-	-	33 4
2019	13	GTIG		3 6	33 0		-	-	36 6
2019	2	NUCL		10 6	97 4	-	-	-	108 0
2020	7	FOL6	-	-	9 2	84 3	-	-	93 5
2020	1	COAL		-	3 0	27 5	-	-	30 5
2020	1	CCIG	-	-	8	7 5	-	-	8 4
2020	4	GTIG		-	1 1	10 1	-	-	11 3
2020	2	NUCL	-	-	10 6	97 4	-	-	108 0
2021	6	FOL6	-	-	-	7 9	72 2	-	80 1
2021	2	COAL	-	-	-	6 0	55 1	-	61 1
2021	7	GTIG	-	-	-	1 9	17 8	-	19 7
2021	2	NUCL	-	-	-	10 6	97 4	-	108 0
2022	6	FOL6	-	-	-	-	7 9	72 2	80 1
2022	2	COAL	-	-	-	-	6 0	55 1	61 1
2022	10	GTIG	-	-	-		2 8	25 4	28 1
2022	2	NUCL	-		-		10 6	97 4	108 0
END TOTAL			171 2	187 3	252 3	253 3	269 7	250 1	2888 6

CAPITAL CASH FLOW SUMMARY OF CANDIDATES (MILLION $)

	FUEL			CONSTRUCTION			IDC			
YEAR	DOM	FOR	TOTAL	DOM	FOR	TOTAL	DOM	FOR	TOTAL	GR TOT
1993	00	00	00	00	00	00	00	00	00	00
1994	00	00	00	00	00	00	00	00	00	00
1995	00	00	00	6 19	18 56	24 75	30	91	1 22	25 96
1996	00	00	00	27 40	83 86	111 26	2 00	6 07	8 07	119 33
1997	00	00	00	90 15	288 23	378 38	8 02	25 12	33 14	411 52
1998	39	4 64	5 03	200 88	707 65	908 53	23 28	77 08	100 36	1013 92
1999	4 01	44 51	48 52	263 43	898 26	1161 69	48 78	164 93	213 70	1423 91
2000	4 01	17 60	21 61	300 13	855 18	1155 30	41 62	129 30	170 92	1347 84
2001	4 01	7 22	11 22	436 75	1210 52	1647 26	62 40	163 35	225 74	1884 23
2002	4 01	71 21	75 22	631 01	1605 43	2236 44	118 08	305 03	423 12	2734 77
2003	4 01	52 35	56 36	758 72	1698 79	2457 51	128 58	303 15	431 73	2945 59
2004	4 01	68 49	72 50	902 03	1896 53	2798 56	183 35	368 53	551 88	3422 94
2005	4 01	26 26	30 26	1060 73	2092 24	3152 97	233 01	411 96	644 97	3828 20
2006	4 01	61 53	65 54	974 32	1977 20	2951 52	244 09	456 35	700 44	3717 50
2007	4 01	55 65	59 65	944 63	2161 02	3105 65	313 65	570 95	884 60	4049 90
2008	3 61	74 87	78 49	1057 93	2544 83	3602 75	232 12	548 63	780 75	4461 99
2009	00	112 41	112 41	1139 14	2620 99	3760 12	238 48	538 67	777 14	4649 68
2010	00	115 56	115 56	1226 74	2953 31	4180 05	296 28	618 88	915 16	5210 77
2011	00	144 38	144 38	1193 46	3069 98	4263 44	311 63	688 28	999 90	5407 73
2012	00	155 89	155 89	1052 81	2994 37	4047 18	293 75	687 27	981 02	5184 08
2013	00	148 21	148 21	1008 02	3080 75	4088 77	255 32	646 12	901 44	5138 43
2014	00	171 18	171 18	1099 53	3465 80	4565 33	218 60	643 02	861 62	5598 13
2015	00	172 87	172 87	1247 48	3837 61	5085 08	238 96	693 45	932 41	6190 36
2016	00	171 23	171 23	1411 17	4165 92	5577 08	268 32	768 11	1036 43	6784 74
2017	00	187 25	187 25	1592 15	4709 73	6301 88	313 41	881 49	1194 89	7684 02
2018	00	252 30	252 30	1821 78	5432 41	7254 19	359 35	1011 37	1370 73	8877 23
2019	00	253 28	253 28	1596 88	4633 55	6230 43	387 05	1070 94	1457 99	7941 69
2020	00	269 68	269 68	1015 60	3080 53	4096 13	325 98	908 13	1234 11	5599 92
2021	00	250 07	250 07	313 04	1051 53	1364 58	196 27	556 14	752 41	2367 06
DOM	40 07			23372 05			5342 66			108021 40
FOREIGN		2888 64			63134 76			13243 22		
TOTAL			2928 71			86506 84			18585 88	

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ABBREVIATIONS

AFBC	atmospheric fluidized bed combustion
ASAG	applied systems analysis group
BBL	barrel
BTU/lb	British thermal unit per pound
C&F	cost and freight
CC	combined cycle
Cal/cm^2	calorie per square centimetre
CANDU	Canadian deuterium uranium reactor
CHASNUPP	Chashma Nuclear Power Project
CIF	cost, insurance and freight
CMI	census of manufacturing industries
CNG	compressed natural gas
DGNRER	Directorate General of New and Renewable Energy Resources
DGPC	Director General of Petroleum Concessions
DNP	Directorate of Nuclear Power
EHV	extra high voltage
EIA	environmental impact assessment
ENERCON	National Energy Conservation Center
ENPEP	energy and power evaluation program
ENS	energy not served
EPAs	environmental protection agencies (provincial)
EUAD	Environmental and Urban Affairs Division
FBC	fludised bed combustion
FBS	Federal Bureau of Statistics
FGD	flue gas desulphurization
FINPLAN	financial planning model
FO	furnace oil
GATT	General Agreement on Tariff and Trade
GDP	gross domestic product
GOP	Government of Pakistan
GT	gas turbine
GTZ	Gesellschaft für Technische Zusammenarbeit
GW	gigawatt
GWh	gigawatt hour
HDIP	Hydrocarbon Development Institute of Pakistan
HESS	Pakistan Household Energy Strategy Study
HOBC	high speed diesel
HSFO	high sulfur furnace oil
HT	high tension
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency
ICRP	International Commission for Radiological Protection
IDC	interest during construction
IIASA	International Institute of Applied Systems Analysis
IPCC	Inter Governmental Pannel on Climate Change
JICA	Japan International Cooperation Agency
KANUPP	Karachi Nuclear Power Plant
KESC	Karachi Electric Supply Corporation
kV	kilovolt
kW·h	kilowatt·hour
kWp	kilowatt peak power
LDC	load duration curve

LDO	light diesel oil
LOLP	loss of load probability
LPG	liquefied petroleum gas
LT	low tension
LWR	light water reactor
MAED	model for analysis of energy demand
MAF	million acre feet
Mcal	mega(million) calorie
MTOE	million tonnes of oil equivalent
NGO	non-government organization
NO_x	nitrogen oxides
NTRC	National Transport Research Center
O&M	operation and maintenance
OCAC	Oil Company Advisory Committee
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PAEC	Pakistan Atomic Energy Commission
PARCO	Pak-Arab Refinery Limited
PCAT	Pakistan Council for Appropriate Technology
PCSIR	Pakistan Council of Scientific and Industrial Research
PEPA	Pakistan Environmental Protection Agency
PEPC	Pakistan Environmental Protection Council
Pkm	passenger kilometer
PSAR	preliminary safety assessment report
PSEDF	Private Sector Energy Development Fund
PSIC	Pakistan Standard Industrial Code
PWR	pressurized water reactor
R/P	reserve to production ratio
REDP	regional energy development program
Rs	Rupees
SCR	selective catalytic reduction
SO_2	sulfur dioxide
T&D	transmission and distribution
TDS	total dissolved solids
TOE	tonnes of oil equivalent
TSS	total suspended solids
TWh	terawatt hours
UHV	ultra high voltage
WAPDA	Water and Power Development Authority
WASP	Wien Automatic System Planning Package
WEC	World Energy Council
WTO	World Trade Organization

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