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REPORT TO THE PRESIDENT OF THE
INTERNATIONAL BANK FOR RECONSTRUCTION AND DEVELOPMENT
AS ADMINISTRATOR OF THE INDUS BASIN
DEVELOPMENT FUND

STUDY OF THE WATER AND POWER RESOURCES OF WEST PAKISTAN

VOLUME IV

Program for the Development of Power

Prepared by a Group of the World Bank Staff

Headed by

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Volume IV consists of eleven chapters and eleven annexes, for which a detailed table of contents is given in the following pages. The Volume is bound in three separate sections:

1. The eleven chapters of the main report, immediately following the table of contents below,

2. The eleven annexes, including the full text of all of them except Annex 10, and

3. The full text of Annex 10.

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I. INTRODUCTION

1.01 This section of the Bank Group's report deals with the development of power in West Pakistan. Over a period of two years the Bank Group's consultant, Stone & Webster Overseas Consultants Inc., of New York, made a detailed study of the most practical means of developing power production in keeping with the needs of the economy. Their findings together with a vast amount of data, supporting information, reasoning, conclusions and recommendations are contained in a two-volume report dated May 1966.

1.02 At the beginning of the Study the general lines of procedure, terms of reference and the principle of full cooperation between the Bank Group, Stone & Webster, the Bank's irrigation, agricultural and dam sites consultants, and the Government of Pakistan (GOP), including its agencies and consultants were established. This excellent cooperation has been maintained through a power coordinating committee which met on several occasions, and to a greater extent informally through the exchange of views and information between all concerned.

1.03 This Bank Group's report is essentially based on the work and findings of Stone & Webster. In a number of cases, Stone & Webster's data have been reproduced as a means of documenting the Bank Group's conclusions and recommendations. In reviewing Stone & Webster's report, the Bank Group has been influenced by the views expressed by the GOP on the consultant's findings, by its own experience in Pakistan and to some extent by developments and information which have become available since the consultants completed their field work late in 1965 and their report in May 1966. In a study of this complexity, where judgment must play such an important part in the interpretation of data and analyses, it is not surprising that -- while there is a great measure of general agreement -- the Bank Group's conclusions differ in some important respects from those of its consultant.

1.04 The Bank Group's report, in accordance with the objective of the Indus Special Study, focuses attention on the development of power generation and bulk transmission facilities over the period to 1985. It further concentrates on the determination of a feasible action program capable of meeting the projected power load during the decade, 1965 to 1975. To this end, the report particularly emphasizes the generation, transmission and distribution facilities which are proposed for installation in the Third and Fourth Plan periods (1965 to 1975) in addition to ongoing projects. Such a program, however, must be developed within the context of longer term planning and development and its implications for future resource development have also been assessed in this report.

1.05 While the report does not aspire to being a master plan for power development in West Pakistan, the Bank Group considers that the action program proposed is consistent with the resources available, the immediate needs of the country and future development planning. Also, the extensive system studies carried out both by Stone & Webster and the Bank Group provide a useful guide to future planning of power development.

1.06 The work of Stone & Webster has been divided in two stages. The first stage covered the power aspects of the Tarbela Project and was completed on December 31, 1964. On March 13, 1965 the power consultant was given "Guidelines for the Comprehensive Study of Electric Power in West Pakistan". The objectives of this Study, except for minor modifications, were governed by the Terms of Reference -- Study of Electric Power -- as set forth in the Indus Special Study Terms of Reference dated June 5, 1964. The Guidelines and Terms of Reference are reproduced as Annex 11 to this volume.

1.07 The report of Stone & Webster on the second stage of the Study, presented in two volumes, was coordinated with companion reports prepared by other consultants outlining plans for the development of the water resources of the Province for use by agriculture. Releases of water stored in the reservoirs, developed by IACA, the irrigation and agricultural consultants, were utilized by Stone & Webster to calculate power benefits. The power consultant also based his work on the survey of hydroelectric resources carried out by the Bank Group's dam sites consultant, Chas. T. Main International, Inc.

1.08 Stone & Webster, in the second phase of their assignment under the Indus Special Study, prepared a $3 billion twenty-year program for the development of electric power in West Pakistan. About 50 percent of the total cost of the program was accounted for by a specific schedule of investments in generation and transmission facilities, and it is with this portion of the overall power program that this volume is primarily concerned. The generation and transmission program prepared by the power consultant was built around the Tarbela Dam which, it was envisaged, would be completed by 1975. The cost of this dam, which is about $800 million excluding power units, is not included in the figures cited above because the primary purpose of the dam would be agricultural. Besides 2,100 mw installed capacity at Tarbela, the power consultant's program also included an additional 900 mw installed hydroelectric capacity in the north of the Province and more than 3000 mw of thermal capacity, roughly equally divided between Karachi in the south and Mari in the center of the Province. The program envisaged that all the main concentrations of electrical load in the Province would be linked together in the early 1970's with a 380-kv transmission system.

1.09 The existing power supply of West Pakistan is concentrated in four main systems which are discussed below in Chapter II. The maximum capability of public utility generating units in the Province during the high water season was 822 mw by the end of 1965. This figure makes it readily apparent that the program outlined above, and particularly the Tarbela Project, is of an entirely different order of magnitude from any generating plant constructed in West Pakistan in the past. Tarbela's installed capacity of 2100 mw is more than twice the capacity of all existing generating equipment in the Province and more than five times the 1965 peak load on the largest of the existing power systems. There are other important features peculiar to a program including Tarbela that need special consideration. Under the current construction schedule it will take eight to

nine years to build Tarbela. Current schedules foresee the installation of twelve 175-mw generating sets by the early 1980's. Because the primary purpose of the dam is to create a reservoir which will store water in the flood season for subsequent release for irrigation purposes in the dry season, the heads on the turbines and hence the peak loads that they can carry will fluctuate tremendously over the course of the years; peak capability in the flood season of about 2,500 mw (with twelve units installed) may be four to five times as great as the capability available in the spring when the reservoir has been drawn down to meet irrigation requirements.

1.10 One of the prime tasks of this report is, therefore, to reassess the power benefits of Tarbela. Definition of exactly what constitutes the power benefits of a project is a disputed question. The difficulty arises because the price for which electric power is sold is an administered price and therefore may not give a good indication of the true average market value of electric power, let alone its marginal value. At the same time electric power is generally a very small item in the total budget of an enterprise or household; another characteristic is that supplies of power from an electric utility can usually be substituted by generation by an enterprise itself or by other forms of energy. In this sense electric power is different from irrigation water, which is critical to the agricultural production process and a less easily substitutable input than electricity supplied by a utility. However, the fact that a number of other ways exist to produce electricity does mean that it is possible to define alternative development programs for the power sector all capable of meeting projected power loads. One program, for instance, can be built up including Tarbela and another excluding it, and both have to be refined to ensure that they are reasonable approximations to what would be the best courses of action, as far as can now be foreseen, under the two assumptions. Then the economic costs of the two programs (i.e. costs excluding duties, taxes and interest during construction) can be discounted to a common basis -- generally 1965 in the following chapters -- and compared, in order to indicate which of the two places a smaller burden on the economic resources of West Pakistan. Costs discounted to 1965 are generally referred to in this volume as "present-worth costs". Net benefits of a particular project, e.g. Tarbela, are defined as the difference between the present-worth cost of the best program including Tarbela and the present-worth cost of the cheapest alternative program excluding Tarbela which can meet the same requirements of power with equivalent reliability of supply.

1.11 All the present-worth calculations in this volume, as in most of the other volumes of the Indus Special Study Report, are made in terms of a synthetic discount rate of 8 percent. The level at which this rate should be set depends primarily on the rate of return obtainable on capital used outside the power sector (i.e. the opportunity cost of capital) and on the time preference of individuals in Pakistan -- both of which are extremely hard to estimate in a meaningful way. The rate of 8 percent finally chosen for the Study is somewhat above the interest rate at which the Government of Pakistan raises money and somewhat below typical rates of return on private investments.

1.12 Adoption of an approach of this nature for evaluation of the Tarbela Project has two implications for the load forecast used. The first implication relates to the time element. The sheer physical fact that the Tarbela Dam will take eight to nine years to build means that the earliest load of relevance is that of 1975. Moreover, since under any foreseeable circumstances, the load of the Province will not be sufficient at that time to absorb the whole of Tarbela's contribution to power supplies, the growth of the load in the years following 1975 will be of critical importance. It will determine how quickly it is worth installing the power units at the dam and hence how quickly the power benefits can be realized. The question of the speed with which Tarbela units can be absorbed actually has a space dimension as well as a time dimension, since before Provincial power load as a whole becomes relevant the different power markets described above have to be linked together by a transmission system capable of carrying large quantities of power. Hence the geographical pattern of load growth is important, and the power aspects of Tarbela, including the scheduling of its units, cannot be studied in isolation from power transmission. However, a considerable part of the benefit of an EHV (Extra High Voltage) transmission system, as will be seen below in Chapter VI will arise in later years, after 1985. Thus the load forecast that is needed for evaluation of Tarbela must be at least twenty years long, and must include considerable detail on the regional distribution of load growth. The critical role of the long-term forecast becomes still more apparent when attention is turned from definition of the overall "benefits" of the project to consideration of its optimum timing; a large project of this nature may show substantial benefits if constructed immediately, but it may also show yet more substantial benefits if postponed to some later date when the demand for power has increased. This question is examined in Chapter VI, where it is found that delay in the execution of Tarbela would in fact be disadvantageous.

1.13 Adoption of this approach puts the physical load forecast in a place of tremendous importance. The power load is forecast and those power projects are selected which meet the forecast load at least cost. The calculations of benefits as defined in the above paragraphs are almost entirely internal to the power sector once the load forecast has been made. Everything depends on the load forecast. If it is too high relative to the growth in demand then the net benefits of a project will appear too high and, in addition, unduly large amounts of money will be devoted to the power sector. On the other hand, if it is too low, then serious disruption may result in the rest of the economy. Thus, the approach used puts on the load forecast the burden of ensuring balance between the growth of the power sector and the growth of other sectors of the economy. Therefore, while it is interesting to consider the sensitivity of the power benefits of a project to different load forecasts in view of the uncertainty that inevitably surrounds 20-year projections, it is essential to ensure that the main load forecast used is consistent with all that is known

about the prospective development of other sectors of the economy. This is why much attention is concentrated in Annexes 1-3 on examining the consistency of the power load forecast with the Pakistan Perspective Plan and with the implications of the rest of this report for economic growth in West Pakistan. The regional load forecasts which came out of those studies and which were used as the basis for most of the analyses presented in this volume are shown in Chapter IV, along with an alternative higher load forecast for the Northern Grid area which was used in certain of the studies, such as that involving different transmission programs.

1.14 It is not only the power load forecast which has to be considered on a long-term basis and in the context of the prospective growth of other sectors of the economy, but also the whole question of alternative sources of electric power, against which a specific hydroelectric project can be compared in order to assess its benefits. There are three main alternative primary sources of power generation which, as far as can now be foreseen, may be relevant for West Pakistan over the next 20 to 30 years (see detailed discussion in Annex 4): other hydroelectric schemes, gas-fired thermal equipment and nuclear plant. Each of these has to be considered and carefully compared in order to reach a reasonable version of the 'cheapest alternative' program; and consideration has to be given to the value of the main scarce resources. But these resources will be used for other purposes besides the generation of electric power, so that a proper appraisal of their scarcity value cannot be made in isolation from the requirement of other sectors of the economy for them. As regards foreign exchange, for example, use has been made in this volume of the results of a study discussed in the Economic Annex to the Report which suggested that the current scarcity value of foreign exchange should be considered, for planning purposes, to be in the neighborhood of twice the current official exchange rate. Consideration of the Perspective Plan suggested that the general scarcity value of foreign exchange would not fall; consideration of the energy sector itself in Annex 4 suggested that foreign exchange stringency in that sector might become more acute. As regards natural gas detailed consideration was given to alternative uses and their likely growth over the coming 20 to 30 years, as described in Annexes 4 and 5. Besides long-term trends in Pakistan, some view has to be taken as to long-term trends in the world at large -- for instance in the price of liquid fuel, the export market for fertilizer, and technological development in the nuclear power industry. The extent to which it may be desirable to use natural gas reserves for power generation depends partly on alternative uses for gas in coming years and partly on the extent of technological progress foreseeable in the development of other energy sources. If nuclear power or liquid fuel were to become cheap, say, in 20 years' time, and if the foreign exchange that Pakistan would have to set aside to import them would not curtail too seriously the import of other needed commodities, then it would matter little if most of the Province's gas reserves were to be used up in the meantime. Thus, a long-term view of the overall energy situation is as essential as a long-term view of the demand for electric power in evaluation of Tarbela; and both views must be adopted within the framework of the overall pattern of growth to be expected in the Province.

1.15 Some of the points made in the last few paragraphs can be illustrated by reference to the agricultural sector which accounts for a very high proportion of the output (over 40 percent) and of the employment (about 55 percent) of the West Pakistan economy. Integration of the power load forecast used in these studies with proposals made elsewhere in this report with regard to agriculture was largely a matter of using a forecast of tubewell pumping load (including its monthly distribution) consistent with those proposals, a forecast of rural electrification that took cognizance of the extensive tubewell fields that were proposed, and a forecast of industrial load consistent with requirements of the agricultural sector for manufacture of inputs such as fertilizer and for processing of agricultural output. With regard to the availability of fuel, account had to be taken of the large amounts of natural gas that would be required to produce sufficient fertilizer to meet the needs of the agricultural development program; the more fertilizer needed the more natural gas would be required to produce it, the less gas would be available for power generation and the higher would be the scarcity value of the gas (see Annexes 4 and 5). The fact that the Tarbela Dam is a multipurpose project also means that there is a need for rather precise specification of its power benefits, since the project is justified on the basis of the sum of its agricultural and its power benefits. Moreover, decisions regarding operation of the reservoir will often require comparison of agricultural benefits of one operational policy -- such as a low minimum drawdown level -- against the power benefits of a conflicting operational policy -- such as a higher minimum drawdown level.

1.16 These various dimensions of a comprehensive long-term approach converge not only in an expression of the benefits of the Tarbela Dam or of a particular mode of operation of its reservoir, but also in a program for the development of the power sector which recognizes that Tarbela will be completed about 1975 and includes appropriate interim and concurrent additions to the Province's energy system. The chapters toward the end of this volume give considerable attention to the implications of the advent of Tarbela in 1975 for system development in the interim, all within the framework of the overall energy and fuel price outlook that may be anticipated with Tarbela completed by that date. Chapter VI for instance reaches the conclusion that if Tarbela is completed by 1975 then a large-scale transmission system is warranted, and it is worth bringing it in, especially some parts of it, prior to the completion of Tarbela. There are many other implications of the long-term perspective with Tarbela for short-term development in the next five to ten years, especially regarding the types and location of thermal equipment which should be installed, the types of fuel that should be used for thermal generation, and the types of facilities that should be built to supply gas, especially for purposes of thermal generation. Such matters are discussed at various points in the following chapters.

1.17 Most of the discussion in the paragraphs above has been in terms of alternative power programs rather than alternative power projects, and it was in fact largely by means of comparison of programs that the Bank Group carried out its studies. An electric power system is such a tightly integrated entity that it is hard to see what will be the impact of any particular system addition except in the context of an overall program. The difficulty arises chiefly from the fact that fuel costs represent a relatively large proportion of the total expenses of an electric utility and that they are determined by the complex interaction of different system elements. For example, fuel accounts for about 30 percent of the total expenses, including interest and depreciation, of the Karachi Electric Supply Corporation, Ltd. (KESC) and for between 15 and 20 percent of the total expenses of the Water and Power Development Authority of West Pakistan (WAPDA) Power Wing (considerably less mainly because of the dominance of hydroelectric supplies in the WAPDA system). Addition of a new thermal plant to a system may have the effect of reducing total system fuel costs if it is much more efficient than existing plants and consequently takes over supply of most of the energy previously produced by them. The effect of a new hydroelectric plant on total system fuel costs will be much more complicated, especially if, like Tarbela, it has a power output which varies significantly at different times of the year. Depending on the size of the power demand and on the variation of demand over the course of the days and weeks it may, for instance, be impossible to absorb all the energy that the hydroelectric plant can produce even though thermal equipment has to be brought into use at the same time. This may sometimes be the case with Tarbela in the spring when the heads on the turbines are low so that the instantaneous load which they can carry is severely limited. In some other months, such as during the release period, it may be energy rather than peaking capacity which will be limited at Tarbela, while in yet other months Tarbela may simply produce more energy and have more capability than the system can absorb. The extent of the effect of these varying patterns of power output at Tarbela on system fuel costs will vary considerably according to what other hydroelectric plants are on the system at the same time and the nature of their power outputs at different times, and depending on whether transmission capacity is available to carry power to the South, and also on the extent and location of thermal capability on the system.

1.18 The ability of the Bank Group to study the problems of system development in a program context was largely due to the availability of a computer model which simulated the operation and growth of the electric power system of West Pakistan, month by month, over the period 1966-85. This simulation model was set up essentially as a tool for comparing alternative programs for the development of generation and bulk transmission in all the main power markets of West Pakistan. Data were fed into the computer regarding the capabilities, heat rates, fuel cost and operating costs of possible new thermal plants; the capital and operating costs and monthly patterns of capability and energy output, with different numbers of units installed, of the existing and proposed hydroelectric

plants; the capital and operating costs and carrying capacities of proposed transmission lines between Lyallpur and Mari and between Mari and Karachi; economic factors such as discount rates and foreign exchange rates; and finally, details of the prospective monthly loads over the 20-year period 1966-85, in each of the three markets mentioned above. The computer was then given a 'strategy', or schedule, according to which the various thermal plants, hydro plants and transmission lines will be added to the system (or, in the case of plant retirements, removed from the system) over the 20-year period. The computer calculated and added up all the costs involved in the operation of the system (capital costs, maintenance and operating costs and fuel costs) in each year of the Plan period, computing them under different assumptions regarding fuel prices and the foreign exchange rate, and discounted them back to 1965. The end result was an array of figures representing the present worth of total system costs over the 20-year period, at different fuel prices and foreign exchange rates.

1.19 In addition to summarizing the total costs of a development program over the Plan period the computer was also programmed to print out a large amount of additional material -- about 25 pages in all -- regarding each development program studied. Most of this material (which is described in detail in Annex 10) concerns the operation of the system in each month of the 20-year planning period. It shows approximately how the hydro plants and thermal plants in each market and the transmission lines linking the markets may be used most effectively under the conditions created by the development program being studied. This information is extremely valuable because it helps to show why the total costs of any particular development tt program turn out as they do relative to the costs of other programs. Much use was made of the detailed data regarding system operation in the refinement of programs and in studies of matters such as fuel requirements in different areas and the effect of transmission line capacity on the absorption of hydro energy.

1.20 One major advantage accruing from the availability of detailed data on system operation was that it made possible the adoption of an approach to fuel pricing, discussed in detail in Annex 5, which took some cognizance of the differences between programs in their requirements of thermal fuel -- not only absolutely over the whole 20-year period, but year by year, as depletion of fuel reserves continued. A number of the most important comparisons discussed in the following chapters are presented in terms of so-called 'economic' fuel prices (as well as financial fuel prices) and this means that the total amount of thermal fuel required in each year was derived from the computer print-out, revalued in terms of the appropriate economic fuel price series shown in Annex 5, discounted back to 1965 and added back into total system costs in place of the fuel costs computed in the simulation model on the basis of a fuel price that was uniform over the whole 20-year period.

1.21 The experience that the Bank Group had in the preparation of this report convinced it that a computer model which simulates the operation of the West Pakistan power system could be of considerable assistance to the Pakistan authorities in reaching decisions regarding investments in power generation and transmission. One of the difficulties facing the Bank Group in the completion of its report was that, soon after Stone & Webster finished their work, important changes took place in the best estimate of fuel reserves in West Pakistan. As a result, as will become apparent in following chapters, important conclusions regarding transmission and the location of thermal capacity had to be reanalyzed. WAPDA is continuously up against this difficulty; almost every report which it receives (and this will of course apply equally to this one) is, by the time that it finally appears, to greater or lesser degree out of date. The conclusions and recommendations regarding system development which are presented in this volume are based on the best data available to the Bank Group in early 1967. Inevitably there will soon be further changes in basic data -- perhaps, for instance, about the thermal value of Lakhra coal or the price of gas turbines -- which will make it necessary to reanalyze some of the conclusions reached here. Planning has to be a continuous process; but it also has to be a quick process if decisions are to be based on the best information available at the time they are made. It is essential therefore that WAPDA develop some approach which will enable it to identify the implications for system development of changes in knowledge of fuel resources, expectations regarding loads, etc., as and when they occur. It is because of its belief in the usefulness of a simulation model for this purpose that the Bank Group has included in this report a considerable amount of detail about the particular model which it used and about the way it works. The model itself could undoubtedly be improved and made more comprehensive, but the Bank Group feels that the type of approach which use of a system simulation model makes possible is one that could help considerably both to accelerate and to improve Government decisions regarding power system development.

1.22 In summary, the chapters which follow in this report divide themselves roughly into two parts. The first four are largely concerned with discussing the existing power situation in West Pakistan, the past growth in power demand and conclusions regarding the forecast of future demand within which a power development program should be formulated. Chapters V-VII are concerned with drawing out the implications of the conclusions reached in the first four chapters for development of the power potential at Mangla and Tarbela and for the assimilation of this potential into the power system. Chapter VII presents an outline program for the development of bulk power supply and transmission, covering the period 1966-85, but with particular emphasis on the years up to 1975. Chapter VIII discusses briefly the very important problem of distribution -- which accounts for nearly half the investment cost of the whole 20-year program proposed. Chapter IX discusses tariffs and organizational problems and Chapter X sets forth the financial requirements of the program. Finally, Chapter XI gives a summary of the conclusions of this volume.

1.23 Following the chapters are 11 annexes and their appendices which discuss in greater detail the various generation and transmission projects considered and indicate how the conclusions presented in the main report were reached. The first three annexes discuss the load forecasting problem and experiment with some techniques for forecasting residential and industrial loads; they also give the details of the load forecasts which underlie the study. Annex 4 sets the overall framework of past and prospective demand for energy, both electrical and non-electrical, within which the power program was prepared, and discusses the major primary sources of energy available to West Pakistan and the costs of developing them. Annex 5 presents the method used for determining an economic price of fuel and also gives other detailed information regarding fuel prices. Annex 6 discusses West Pakistan's hydroelectric potential, indicates the place of Tarbela and Mangla within that total and discusses some of the economic questions that arise in connection with hydroelectric development; in addition it presents technical and financial details of the various hydroelectric projects considered; the methods used for simulating the operation of the reservoirs at Mangla and Tarbela on a 10-day basis are also described in this annex and its accompanying appendices. Annex 7 outlines the analyses that were made of the Tarbela Project -- regarding both its overall power benefits and also operating policy on the reservoir once built. Annex 8 covers the questions that arise concerning Mangla -- the timing of the addition of power units, operating policy, and the possibility of raising the dam some 50 feet. Annex 9 discusses the analyses that were made of electricity transmission and, intimately related to that, of gas transmission. Annex 10 describes at length the simulation model which was built for the West Pakistan power system and which was used extensively in the analyses underlying the report. It starts with a non-technical introduction of the simulation model and the way it works and subsequently gives full details of the various subroutines which make up the model. Finally, Annex 11 presents the Guidelines and Terms of Reference for the power consultant.

II. THE EXISTING SITUATION

2.01 The consumption of energy in West Pakistan has been moderate even by the standard of countries which are the lowest consumers of energy. Until quite recently the major uses of energy were in the form of animal power or relatively simple conversion of minerals into forms of heat for cooking and space heating. It is only recently, as transport and industry have grown in importance, that energy in the form of power -- and particularly in the form of electric power -- has been needed on a large scale. It has been substituted for mechanical power in older industries, electric lights have been replacing kerosene lamps in homes and electricity has been introduced into new areas to render services not previously performed.

2.02 The Bank Group has prepared rough estimates which indicate that in 1950 the level of total energy consumption in West Pakistan was about 275 trillion Btu's. Of that, only about 40 trillion Btu's or about 15 percent was in the form of commercial energy. Electricity consumption was only 200 million kwh, equivalent to about 3 trillion Btu's -- or only a little more than 1 percent of total energy supplied. By 1964 commercial energy consumption was up to nearly 40 percent of total energy consumption -- about 185 trillion Btu's out of a total of 500 trillion. The share of electricity in total supplies of energy had risen above 10 percent. In absolute terms the supply of electricity in West Pakistan increased from about 780 million kwh in 1955 to over 3,700 million kwh in 1965 or at an average annual growth rate of about 17.0 percent. Out of nearly 40 countries for which data are readily available (see Annex 1) only one country had a growth rate of electricity production over these same years in excess of this level. This growth rate had meant an increase in per capita consumption of electricity of nearly 50 kwh over a nine-year period, i.e from about 20 kwh in 1955 to some 70 kwh in 1965.

2.03 At the time of Independence, West Pakistan's electric system was in an extremely primitive state. The total installed capacity of public utilities in the Province was only 70 mw consisting of 60 mw in the North and the Sind and 10 mw at Karachi. The rapid development of industry in West Pakistan together with the discovery of natural gas near Sui in 1952 greatly altered this picture. By 1956 a decision had been made to proceed with a large high pressure, high temperature modern thermal station at Multan, based on Sui gas and with a large hydroelectric station on the Kabul River near Warsak. Substantial thermal developments were also taking place in Karachi based on natural gas burning stations.

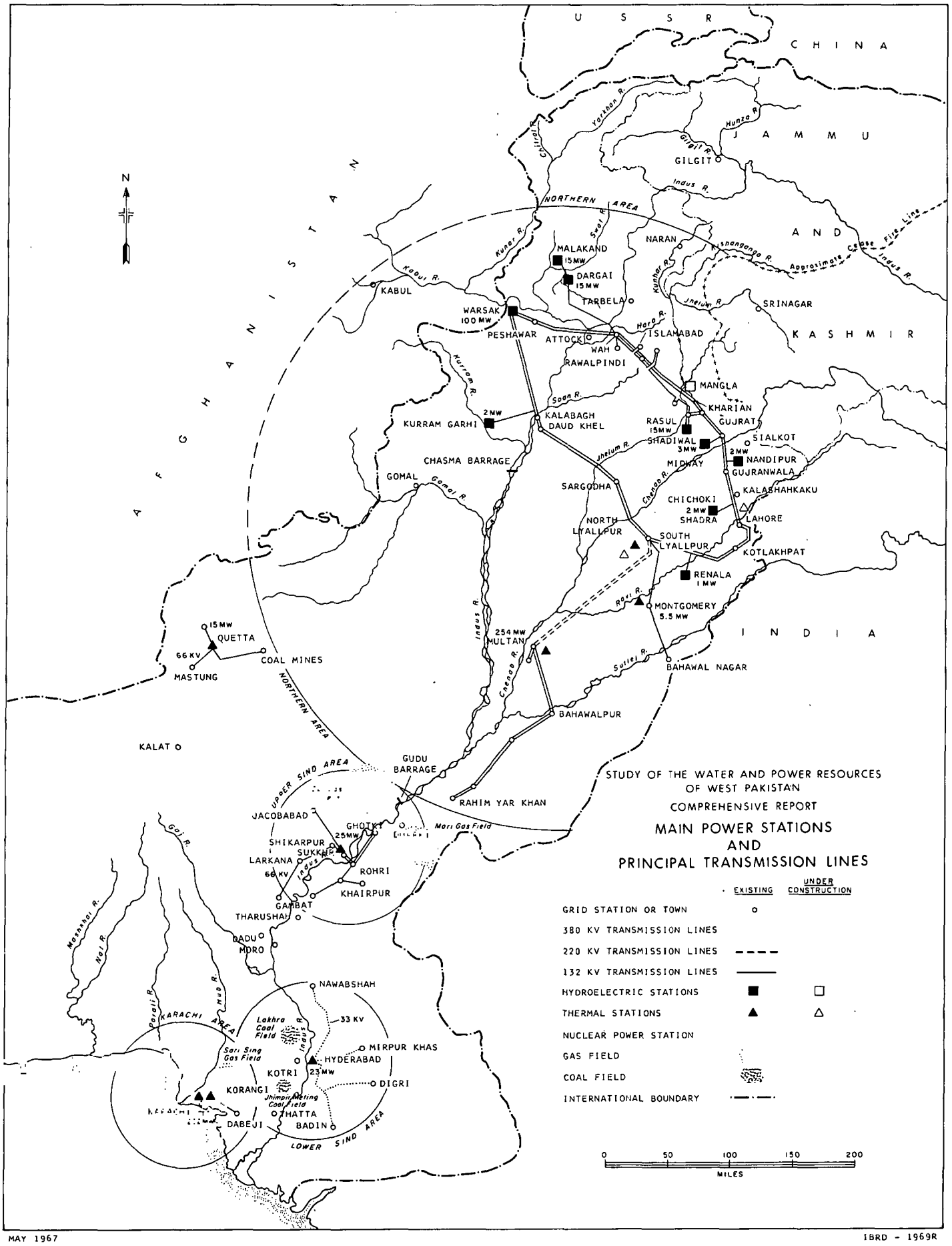
2.04 The growth in the use of gas continued at a rapid pace. By 1964 locally produced gas accounted for nearly 30 percent of commercial energy consumption -- compared with 1.5 percent nine years before. About 45 percent of the gas sold in 1964 went directly to the electric utilities. In addition, with the introduction of the large hydroelectric

facility at Warsak, a situation has been reached where the installed capacity of public utilities is eleven times higher than it was at Independence. The total electric generating capacity in public and private utilities in the Province exceeded 800 mw by the end of 1965. The firm capacity in the low water season was over 700 mw.

The Structure of the West Pakistan Power System

2.05 West Pakistan is served by four regional power systems. These systems, which are not interconnected, cover the following areas: (a) the Northern Area which is the largest of the four and contains all of the hydroelectric capacity in the Province, (b) the Upper Sind, centering on a thermal station at Sukkur, (c) the Lower Sind, centering on thermal stations at Hyderabad, and (d) Karachi, West Pakistan's largest city and its largest seaport and industrial center. These systems, with the exception of Karachi and a few privately owned stations, have been owned and operated since 1959 by WAPDA. Their service areas are shown on the following map and are described below.

2.06 (a) Northern Area. This area extends from the Swat Valley near the border of Afghanistan eastward to the Indian border and southward almost to the Sui and Mari gas fields. It contains more than 75 percent of the population of West Pakistan and accounts for most of the agricultural and much of the industrial production of the Province. The population is 85 percent rural, but the urban population is increasing at a rate of about 5 percent a year. The Northern Area covers altogether about 90,000 square miles and it extends over 500 miles north and south. However, 60 percent of the power load is concentrated in an area about 100 miles square around the major cities of Lahore and Lyallpur. The WAPDA system in this area, often referred to as the Northern Grid, includes all of the hydro plants in the Province. At the time Stone & Webster prepared their study at the end of 1965, the system had a maximum capability in the high water season of 522 mw which was about 65 percent of the total utility capacity in West Pakistan. In the low water season the capability of the system reduced to 432 mw. Of this capacity 16 mw is scheduled to be retired in the next few years. Thermal capacity in the system amounted to 277 mw and consisted of a modern gas-fired steam plant at Multan with a capacity of 250 mw, an older steam plant at Lyallpur of 10.5 mw, and a small steam plant at Montgomery with 5.5 mw. A 6-mw gas turbine at Multan and a 7-mw diesel plant at Lyallpur can be operated during system peaks. The hydro capacity is installed in one large station on the Kabul River near Warsak and in eight small stations on irrigation canals. The Warsak station has four 40-mw generators. These have a capability of 160 mw in the summer but this is reduced to 100 mw in winter owing to downstream conditions. The relatively small hydroelectric stations on irrigation canals contain 28 generators. Their combined capability in summer is about 85 mw which is reduced to about 55 mw in the winter, the variations being governed by available water and irrigation needs. In addition to the above,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NARAN
Kunhar R.
Kishanganga R.
Approximate Cease Fire Line
Jhelum R.
SRINAGAR
WARSAK
100 MW
PESHAWAR
ATTOCK
WAH
RAWALPINDI
Haro R.
ISLAMABAD
Kurram R.
Soan R.
MANGLA
KHARIAN
GUJRAT
KURRAM GARHI
2 MW
KALABAGH
DAUD KHEL
RASUL
15 MW
SHADIWAL
3 MW
SIALKOT
2 MW
NANDIPUR
GUJRANWALA
CHASMA BARRAGE
MIDWAY
GOMAL
Gomal R.
SARGODHA
Chenab R.
KALABAHKAKU
CHICHOKI
2 MW
SHADRA
LAHORE
NORTH LYALLPUR
SOUTH LYALLPUR
KOTLAKHPAT
RENALA
1 MW
Ravi R.
MONTGOMERY
5.5 MW
15 MW
QUETTA
66 KV
MASTUNG
COAL MINES
NORTHERN AREA
254 MW
MULTAN
Indus R.
Chenab R.
Sutlej R.
BAHAWAL NAGAR
BAHAWALPUR
KALAT
GUDU BARRAGE
UPPER SIND AREA
RAHIM YAR KHAN
JACOBABAD
GHOTKI
25 MW
Mari Gas Field
SHIKARPUR
SUKKUR
LARKANA
66 KV
Indus
ROHRI
KHAIRPUR
GAMBAT
THARUSHAH
Gol R.
Mashkhel R.
Nal R.
DADU
MORO
NAWABSHAH
Hub R.
Porali R.
KARACHI AREA
Lakhra Coal Field
33 KV
Sari Sing Gas Field
MIRPUR KHAS
HYDERABAD
KOTRI
23 MW
KORANGI
DIGRI
Jhimpir Meting Coal Field
KARACHI
THATTA
DABEJI
BADIN
LOWER SIND AREA
STUDY OF THE WATER AND POWER RESOURCES
OF WEST PAKISTAN
COMPREHENSIVE REPORT
MAIN POWER STATIONS
AND
PRINCIPAL TRANSMISSION LINES
EXISTING
UNDER CONSTRUCTION
GRID STATION OR TOWN
380 KV TRANSMISSION LINES
220 KV TRANSMISSION LINES
132 KV TRANSMISSION LINES
HYDROELECTRIC STATIONS
THERMAL STATIONS
NUCLEAR POWER STATION
GAS FIELD
COAL FIELD
INTERNATIONAL BOUNDARY
0
50
100
150
200
MILES

there are several privately owned utilities operating in the area. The two largest serve the cities of Rawalpindi and Multan. The Rawalpindi Company (REPCO) has a steam plant with a capability of 8.5 mw and the Multan Company (MESCO) has a diesel plant with a capability of 4.5 mw. Both companies purchase their base supply from WAPDA and use their own equipment at peak periods. Their purchases from WAPDA totaled about 65 million kwh in 1965.

2.07 (b) The Upper Sind contains the Sui and Mari gas fields. Sui gas, which is piped northward to Multan and Lyallpur and southward to Hyderabad and Karachi, is extensively used for the generation of electricity. The Mari gas field is, as yet, not utilized. The Upper Sind system became operative as an interconnected system only in 1965 when a 25-mw gas-fired steam station at Sukkur was completed by WAPDA. Prior to this the area was served with high cost isolated diesel stations. Two more 12.5-mw steam units were added to the Sukkur station in 1967. Several small privately and municipally owned plants are still operating in the area, but it is expected that they will soon be retired.

2.08 (c) The Lower Sind has had a small interconnected system for a number of years. In 1961, as part of a WAPDA system, a new 7.5-mw steam unit was added to the small existing capacity and was quickly absorbed. A second 7.5-mw steam unit was completed in December, 1961, and a 7.0-mw gas turbine was added during 1963 bringing the total capacity of the system to 23 mw. This capacity was absorbed by mid-1964 and load curtailment became necessary. The system is now fully loaded. An 8-mw steam unit was added to the system in 1966 and a 15-mw steam unit was near completion early in 1967.

2.09 (d) Karachi. KESC (Karachi Electric Supply Corporation), which supplies Karachi and the surrounding area, is jointly owned by the Government and private shareholders with the Government holding the majority of the shares. Its total service area encompasses 960 square miles with a population estimated at 2,550,000 in 1965. According to the Pakistan census the population of the city of Karachi grew from 436,000 in 1941 to 1,065,000 in 1951, 1,913,000 in 1961, and 2,044,000 in 1965. This rapid increase resulted both from the substantial influx of refugees from India and from its change of status as one of Old India's seaports to the capital of Pakistan and the country's largest industrial center. (The seat of the Government, however, has been moved to Islamabad and the transfer is expected to be completed in 1968 or 1969.) The generating facilities of KESC in Karachi consist of 247 mw of steam plant and approximately 25 mw of diesel plant. Some units of the diesel plant are 30 years old and have been derated so that its total effective capacity is now only 20 mw. The effective total generating capacity is therefore 267 mw while the firm capacity, with the largest unit out of commission, is 201 mw. The steam plant is concentrated in two stations, Karachi B at West Wharf and Karachi C at Korangi. Karachi B, in the dock area, with a total capacity of 115 mw, contains eight units varying in size from 4 mw to 30 mw installed

between 1946 and 1962; Karachi C is a new station on the eastern boundary of the city with an installtion of two 66-mw sets. The diesel plant is concentrated in two stations. One, with an effective capacity of 4 mw, contains a miscellaneous collection of diesel units varying in size from 370 kw to 2,000 kw each installed between 1936 and 1951. The other station, with an effective capacity of 16 mw, contains 12 identical machines installed between 1961 and 1964. About 15 mw of steam and diesel plant is due to be retired in the next few years. The Pakistan Atomic Energy Commission is constructing a 125-mw nuclear power plant near Buleji, about 15 miles West of Karachi, which is scheduled for commissioning in mid-1970. KESC has agreed to purchase energy from the plant when it becomes available.

2.10 In addition to the four systems described above, there is a small system centering on Quetta in Baluchistan where WAPDA has recently completed a 15-mw steam power plant fired by coal. The plant, which consists of two units of 7.5 mw each, serves the coal mines and two nearby communities through low voltage transmission lines. The demand stated at the end of 1965 was insufficient to load even one of these 7.5-mw units. Baluchistan is mostly a desert and mountainous region situated between the Afghanistan-Iranian border and the lower part of the Indus River. It covers roughly 40 percent of West Pakistan, but contains only 3 percent of its population.

2.11 In recent months the Northern Grid area and Lower Sind have been confronted with serious power crises, while the other two main power markets -- Karachi and the Upper Sind -- appear to have adequate supplies of electricity. The situation in the Northern Grid area has been especially acute, largely as a result of unforeseen mishaps to the units at the main thermal station in the North at Multan and delays in the completion of a new thermal station at Lyallpur. By the middle of 1966 WAPDA had a peak capacity of about 550 mw net (160 mw at Warsak hydro station, 85 mw on eight small hydroelectric stations on rivers and canals, 250 mw in four modern gas-fired steam units at Multan, 26 mw in the two new gas turbines at Lahore, and about 25 mw in miscellaneous small thermal units). Peak demand in August was estimated at about 520 mw net, but the peak which could actually be met was only about 400 mw. Equipment failure at Multan had resulted in the complete outage of one of the units and reduction in capacity of the three other units. The necessity for load shedding grew to even larger proportions in the winter of 1966/67 as a result of the reduction in the capabilities of the hydro units that occurs with the reduced river flows in the winter months. The Lower Sind system has been overloaded for a number of years and load growth was consequently suppressed. Peak demand in 1966 was estimated by WAPDA at about 38 mw but due to the failure of a boiler in a new 15-mw unit, the peak load actually met was only about 28 mw.

2.12 These shortages which have resulted in serious loss of agricultural and industrial production over the last six months

or more should be largely overcome during 1967. By the end of April 1967, with the increase of flows in the rivers and the reduction in tubewell loads, the worst of the power crisis was over. By the middle of the year the first two units at Mangla should be in operation (minimum combined capacity in March-May about 90 mw and maximum capacity in August-September about 260 mw) and two 66-mw steam units should be completed at Lyallpur. In the latter part of 1967 four 13-mw gas turbines should be added to the Lahore station. Therefore, if proper use is made of the time when there will be surplus capacity on the system due to high flood flows on the Jhelum in order to repair the Multan units, it might be possible to bring them back to full rated capacity. In such an event the total net capacity on the system with hydro units stated at their minimum loads by March 1968 would be as follows:

Table 1

W WAPDA Northern Grid Net Capability, March 1968 8
(Megawatts, net of station use)

Warsak Units 1-4	100
Mangla Units 1-2	90
Small hydels	75
Multan steam station	250
Lyallpur steam station	124
Lahore gas turbines	78
Miscellaneous thermal	23
	740

Net capability of 740 mw in March 1968 compares with projected load of about 600 mw on the main load forecast used in this report and 620 mw on the contingency load forecast. Both of these loads are given net of interruption of public tubewells at the peak (see Chapter IV below).

2.13 The existing capacity in the Lower Sind area of about 30 mw should be increased by about 28 mw during 1967 as a result of final completion of the 15-mw steam unit at Hyderabad and installation of a 13-mw gas turbine at Kotri. WAPDA plans to add two more 13-mw gas turbines at Kotri by early 1968 and by the middle of that year a 132-kv transmission connection should be completed between Hyderabad and Karachi.

Transmission

2.14 The various systems described above are reasonably well served with transmission facilities. WAPDA has integrated most of the Northern Grid with a high tension transmission system serving all of the large towns and cities. This network consists of over 1,000 route miles of 132-kv lines and 134 route miles of 220-kv circuits. A double circuit 132-kv line connects the large Warsak hydro facility and other hydro plants in the North with the main load

centers at Lyallpur, Lahore and Rawalpindi. A 220-kv double circuit line, completed in 1965, connects the large gas-fired steam station at Multan with the market area around Lyallpur. The lack of adequate transformer capacity has, until recently, somewhat limited the capacity of this 220-kv line. With the exception of this bottleneck, WAPDA's transmission lines are modern, well laid out and terminate at well equipped substations where the primary voltage is reduced to 66 kv for the secondary network. A complete 66-kv network has been installed to transmit energy to the larger distribution centers where it is reduced to 11 kv, the primary distribution voltage. A new well equipped dispatching center is located near Lahore.

2.15 Karachi is served by a 66-kv loop 55 miles long which encircles the city and interconnects all but one of the six generating stations supplying the city. A second loop of 132 kv has been started which connects a new plant at Korangi into the system. A 69/132-kv double circuit line 18 miles long extending northeastward to Dhabeji is being completed. The distance from Dhabeji to the southernmost part of the Hyderabad system is only 70 miles, and WAPDA expects to start construction soon on a 69/132-kv line to close the gap and interconnect the KESC and Hyderabad systems. The transmission system is generally well constructed and maintained.

2.16 Transmission lines, mostly 66 kv and 33 kv, radiate from Sukkur, Hyderabad and Quetta to serve about 20 small surrounding communities.

Distribution

2.17 At the time of Independence, the power system was relatively small and the distribution networks in the Province were most seriously overtaxed. KESC, in the early 1950's, began renovation and expansion of its distribution system and at present Karachi is reasonably well served with distribution facilities.

2.18 The distribution systems which WAPDA inherited were not designed to cater for the loads which developed rapidly after Independence. WAPDA undertook an extensive renovation and expansion program. Despite the lack of adequate funds and manpower, WAPDA has made progress in providing distribution facilities in many areas under its jurisdiction. However, it recognizes that much remains to be accomplished and in the last few years it has allocated larger amounts of funds for this purpose.

2.19 The total number of customers served by public utilities in West Pakistan is nearly 1,000,000 of which 90 percent are residential and commercial customers. The remainder are industrial, agricultural and miscellaneous. (A customer is defined as a metered connection. The number of people served is estimated to be over six times this number of residential and commercial customers.) Of the 1,000,000 customers in the Province, more than

800,000 are in the areas served by WAPDA and about 155,000 are in Karachi. The power consultant estimated that only 10 percent of all houses in the Province are electrified. The overall figures include both urban and rural customers, and the two categories are discussed below.

2.20 Urban. Stone & Webster estimated that about 34 percent of the houses in urban areas are electrified. This is a reflection of the fact that, while all of the large cities and towns in the Province have electric service, very few of them outside of Karachi have adequate distribution facilities. The cost of making a large number of connections is a deterrent. Nonetheless, a renovation program to upgrade the systems in seven of the larger cities served by the Northern Grid is nearing completion. This program, however, renovates only a small part of the older systems and leaves at least 80 percent of the existing distribution systems in a poor state of repair and much of the area not served in any way. There is, moreover, a substantial backlog of customers waiting to be connected. This is estimated to be in the order of 40,000 in the Northern Grid area alone. It is estimated that the number awaiting connections in Karachi is about 1,800.

2.21 Rural. Stone & Webster, defining rural to include all settlements with less than 25,000 population each, estimated that only about 5 percent of the houses in rural areas are electrified. Such rural electrification as there is has been mainly the work of the last ten years: in the late 1950's a number of villages in the Peshawar area were electrified in connection with the hydroelectric developments there and in the early 1960's many villages in Rechna and Chaj Doabs in the Punjab were electrified in connection with the public tubewell programs in the area. There are in West Pakistan some 40,000 villages of all sizes and types, but about 75 percent of them have less than 1,000 inhabitants each, By mid-1966 there were about 2000 villages electrified in the Province. The achievement in rural electrification has fallen below expectations. In 1961 WAPDA selected 5,000 villages, of at least 1,000 inhabitants each, for electrification during the Second Five Year Plan period. But the program never received the financial support it required. According to WAPDA figures, about 900 villages were electrified during the Second Plan. Most of the rural distribution lines serve tubewells as well as rural communities. It is estimated that by 1965 there were 14,665 electrified public and private tubewells in the Province; they are heavily concentrated in the North, but there are also a few in the Sind and in the vicinity of Karachi. The fact that tubewell programs are now designed to spread over most of the Indus Plains may substantially enhance the prospects of the village electrification program. Plans for tubewell electrification generally provide for surplus line capacity which could serve a part of the rural and village requirements.

III. PAST GROWTH

Generation

3.01 The use of electricity in West Pakistan since Partition in 1949 has, as stated above, grown very rapidly. The rate of growth in the period 1955-65 has been estimated at about 17 percent a year. Accurate statistics prior to 1960 for the area now served by WAPDA are difficult to obtain and the data available for that period can be considered as rough orders of magnitude. Partial information on generation by private utilities (mainly Rawalpindi Electric Power Company and Multan Electric Supply Company) and in industrial plants supplied by their own equipment was available from surveys carried out by the Electrical Inspector in the Central Statistical Office. KESC has kept reasonably good statistics on its generation and sales since Partition.

3.02 From the data available, it is estimated that the annual rate of growth in generation of electricity, including that of industrially owned plants, for the period 1950-55 was about 30 percent but this growth was from a rather low base. From 1955 through 1960 the growth rate was lower, about 16 percent per year, owing largely to the lack of adequate generating capacity throughout the Province. With the establishment of WAPDA in 1959 and the commissioning of large hydro and thermal plants in the North and the expansion of KESC's facilities in Karachi, the rate of growth from 1960 to 1965, including generation by industrially owned plants, was about 17 percent per year. The growth of sales by utilities (which excludes industrially owned generation) in this period, however, was about 21 percent annually.

3.03 By the end of 1965, the total annual generation of electricity was some 3.7 billion kwh. The share of WAPDA was approximately 65 percent; 18 percent was supplied by KESC and an additional 2.5 percent was produced by privately owned utilities located mostly in the North and Baluchistan.

3.04 The remaining 14.5 percent of the 3.7 billion kwh total was accounted for by industrially owned generating equipment. So far as can be ascertained, such establishments produced during the 1950's 25 to 35 percent of the total electric energy generated in West Pakistan. As total electric generation grew, while industrially owned generation remained constant, that share has declined. According to the Central Statistical Office a capacity of about 230 mw was installed by 1963 in industrially owned establishments.

3.05 Energy generated in the Province in 1960 and in 1965 by public utilities and industrially owned equipment is shown in Table 2 below which also shows the generation by various regions of the Province.

Table 2

Electric Energy Generated in West Pakistan, 1960 and 1965
(Million kwh)

	1960	1965
WAPDA		
North	777.4	2,296.0
Upper Sind	2.0	26.7
Lower Sind	28.8	126.1
Baluchistan	0.1	21.2
Subtotal	809.3	2,470.0
Private Utilities	67.6	66.0
KESC	292.1	644.0
Subtotal	1,169.0	3,180.0
Industrially owned generation	520.0	544.0
	1,689.0	3,724.0

3.06 The growth of generation in the North between 1960 and 1965 was about 23 percent per annum and in Karachi it was about 17 percent per annum. Industrially owned generation remained practically static. The principal reason for this was the fact that after 1961 when a reasonably sufficient supply of utility-generated electric power became available to satisfy industrial demands, the Government imposed controls on the importation of industrial generating equipment. New industries were then permitted to install new generating equipment only when utilities were unable to provide the power required; hence, most of the new industrial demand since 1962 has been supplied by utilities. Therefore, the rapid growth of sales by WAPDA and KESC in recent years partially reflects sales to industries previously generating their own power and sales to privately owned industries which did not increase their power producing facilities. It also reflects sales by WAPDA for pumping and for construction power at Mangla.

Peak Demand

3,07 During the early 1960's, there had been substantial load shedding in different areas because of shortages in capacity or distribution facilities. Thus the historical figures on peak loads were not a good guide to actual demand. Stone & Webster therefore built up estimates of non-suppressed demand and energy requirements for 1965 to form the starting point of their projections. Even without this correction the total column on the right in Table 3 gives a good picture of how the demand for power has increased since 1960, although it should be treated with caution because the various utility systems are not interconnected.

Table 3

Peak Demand on Public Utility Systems in West Pakistan, 1960-65
(Megawatts, net of station use)

Year	WAPDA Northern Grid a/	WAPDA Sind and Baluchistan	KESC Karachi	Total c/
1960	152	25	50	227
1961	195	34	58	287
1962	251	37	76	364
1963	314	40	94	448
1964	369	45	110	524
1965 b/	409	34	121	564
1965 without load shedding b/	473	44	136	653

a/ Interconnected system Northern Area.
b/ The 1965 figures are actual peaks. The line below 1965 indicates the base-year figures used by the power consultant for his load forecasts; they represent the peaks which he estimated would have been achieved had there been no load shedding.
c/ The totals are non-diversified peaks. Diversified peaks, however, would apparently be only slightly different.

3.08 The effect of load shedding is indicated in the last line of the table above. Had there been no load shedding, the actual combined peaks would have been about 90 mw higher than the 564 mw achieved in 1965. The Northern Grid and the Sind were proportionally more affected than Karachi.

3.09 Table 4 below shows the fluctuations in the annual load factors in the Northern Grid and in KESC's system. (Load factors are a general indication of the percentage of time the generating facilities are utilized.) Monthly load factors would show greater fluctuations. The decreases in load factor from time to time reflect the addition of new generating capacity to a fully loaded or overloaded system.

Table 4

Annual Load Factors WAPDA and KESC, 1960-65
(Percentages)

	1960	1961	1962	1963	1964	1965
WAPDA Grid	58.2	60.0	61.6	61.9	63.7	61.1
KESC	66.6	64.6	58.0	58.1	61.5	57.0

Consumption by Classes

3.10 The five classifications of sales generally used by public utilities are: residential and commercial (together also termed general); industrial which includes all industrial customers, except railroads and certain other large customers covered by the bulk classification; public lighting which includes all street lighting; bulk which includes residential colonies attached to industrial enterprises, licensees engaged in local distribution for resale, railroads, military establishments and other Government institutions having distribution facilities; agricultural pumping which includes Government and private tubewell consumption.

3.11 The rates of growth of sales during the period 1960-65 varied between regions as shown in Table 5, although complete figures are available only for the Northern area and for Karachi. Total sales in the Northern area grew by 25 percent per year and in Karachi by 18 percent per year. In the North, agricultural pumping grew about two and a half times as fast as industrial sales but sales for pumping grew from a rather low base. In Karachi industrial sales grew substantially faster than residential and commercial sales.

Table 5

Average Annual Growth of Sales by Utilities 1960-65
(Percentages)

Class of Consumer	Total for All Utilities a/	Northern Area	Karachi
Residential and Commercial	21	25	13
Industrial	18	16	20
Bulk and Other	13	30	10
Agricultural Pumping	43	43	-
	21	25	18

a/ Separate figures for the Upper and Lower Sind are not available.

3.12 Figures for actual sales and generation of electricity, distributed by classes, are shown in Table 6.

Table 6

Distribution by Classes of Energy Generated in West Pakistan in 1960 and 1965

	1960		1965	
	Millions of kwh	% of Total	Millions of kwh	% of Total
Residential and Commercial	193	16.5	488	15.4
Industrial a/	576	49.3	1,321	41.5
Bulk and Other Uses	116	9.9	216	6.8
Agricultural Pumping	87	7.4	538	16.9
Total Sales	972	83.1	2,563	80.6
Losses and Theft	197	16.9	617	19.4
Total Utility Generated	1,169	100.0	3,180	100.0

a/ Exclusive of industrially owned.

3.13 It may be seen from Table 6 that the share of industrial consumption in the total has declined somewhat, the share of agricultural pumping has increased, while the share of residential and commercial consumption (the largest part of which is made up by private homes) has remained relatively constant. These different categories will be discussed in more detail in the following paragraphs.

Residential and Commercial Consumption

3.14 The growth of residential and commercial consumption from 1960 to 1965 averaged about 17 percent per year. The number of customers in this classification increased from 412,000 in 1960 to 753,000 in 1965. The increase would probably have been even greater if adequate distribution facilities had been available and if new lines could have been installed more rapidly. The average annual use per customer grew from 535 kwh to about 650 kwh in the five-year period. Table 7 below shows sales to the two classes combined from 1960 to 1965 for the various regions of the Province.

Table 7

Sales to Residential and Commercial Customers, 1960-65
(Million kwh)

	1960	1961	1962	1963	1964	1965
North	95.6	122.0	151.9	175.3	210.6	292.0
Upper Sind	-	2.2	2.6	3.5	4.6	6.0
Lower Sind	6.9	10.5	13.6	15.9	20.7	22.0
Karachi	90.3	95.5	114.4	129.2	154.7	168.0
	192.8	230.2	282.5	323.9	390.6	488.0

3.15 To be truly useful the figures for the combined categories of residential and commercial consumption should be separated into their component parts. This is not easy. Up to 1965, WAPDA, KESC and the other utilities in West Pakistan did not keep separate records either of the customers in each category or of the amount of electricity purchased by them. Records were kept in accordance with tariffs; therefore, when a tariff -- e.g. for lighting -- applies both to residential and commercial customers, the only precise figures obtainable are for the two classes combined. Furthermore, it has not been possible to distinguish accurately between urban and rural customers.

3.16 The power consultant, however, in order to establish a base for his separate forecasts of residential and commercial consumption, devised methods for approximating the consumption in the two classifications in 1965. On this basis, the average use per residential customer in 1965 is estimated to be about 575 kwh annually, while the average use per commercial customer is estimated to be some 1,650 kwh annually. The total consumption of the combined category was around 500 million kwh. Of this, residential consumption alone accounted for nearly 380 million kwh. Out of this total, nearly 350 million kwh was consumed in urban areas (i.e. in towns having a population in excess of 25,000). It was estimated that the level of consumption per house in urban areas was at least six times the level in rural areas.

3.17 The Bank Group was interested in trying to develop a relationship between income distribution and residential electrification to assist in projections of the residential load inasmuch as the residential load is starting from such a low base. Adequate data are not available, but the Bank Group did work up some estimates on the basis of data gathered by Stone & Webster and certain socioeconomic surveys. Table 8 shows the proportion of people in different income groups in urban areas who were estimated to be receiving residential supplies of electricity in the different regions of the country in the period 1960-64.

Table 8

Relationship Between Urban Income Distribution & Electrification 1960-64

	Northern Grid			Sind & Baluchistan			Karachi		
(1) Family Income Group PRs/mo.	(2) % of Pop.in each group	(3) % of (2)con-Nected	(4) % of Pop.con-nected (2x3)	(5) % of Pop.in each group	(6) % of (5)con-nected	(7) % of Pop.con-nected (5x6)	(8) % of Pop.in each group	(9) % of (8)con-nected	(10) % of Pop.con-nected (8x9)
< 100	40.0	15.3	6.1	54.1	9.7	5.2	29.2	7.5	2.2
100-200	39.0	40.8	15.9	32.7	22.6	7.6	38.6	16.4	6.3
200-400	11.0	70.1	7.7	9.0	26.3	2.4	22.0	41.7	9.2
> 400	10.0	95.0	9.5	4.2	50.0	2.1	10.2	75.4	7.7
	100.0		39.2	100.0		17.3	100.0		25.4

Urban electrification is lowest in the Sind and highest in the North. One striking aspect of these numbers is the extent to which electrification reaches families in quite low income groups especially in the North. In the North 15 percent of those with family incomes of less than PRs 1,200 per annum receive domestic supplies of electricity. An explanation of this fact is that poor families are able to have electricity because they join up with others and live several families to one house. In Karachi lower levels of electrification apply to each income group than in the North. This is probably accounted for by the high charges for connections required by KESC.

3.18 The table also indicates that the vast majority of people, even in the relatively prosperous urban areas, has family incomes of less than PRs 200 per month -- about 70 percent in Karachi, 80 percent in the North and nearly 90 percent in the Sind and Baluchistan.

3.19 The number of residential and commercial customers has grown rapidly in recent years, especially in the North. WAPDA has been adding between 70,000 and 80,000 new customers in these groups each year of the Second Plan period. KESC has been adding on average a little over 10,000 new residential and commercial customers each year. No figures are available on the other smaller utilities, but 99 percent of the new connections in these classifications have probably been made by WAPDA and KESC. The figures in the following table refer to customers in the case of WAPDA and to connections in the case of KESC; the two do not correspond exactly -- sometimes there are several connections to one customer and sometimes several customers to one connection -- but the figures presented give an indication of what has been happining in this field. WAPDA figures refer to June 30th of each year, KESC figures to December 31st.

Table 9

Recent Growth of Residential and Commercial Connections
(Number in Existence - in '000s)

	1960	1961	1962	1963	1964	1965
WAPDA	295	339	414	486	564	636
KESC	91	97	110	121	135	147
	386	436	524	607	699	783

Industrial Consumption

3.20 Industrial customers have in the past consumed more electricity than all other classifications combined. Sales to industry increased at an average rate of about 18 percent per year from 1960 to 1965. The industrial sales in the various areas during 1960 and 1965 are shown below. As the figures are for sales, industrially owned generation is excluded. Sales for construction power at Mangla being such a large item are shown separately.

Table 10

Estimated Industrial Sales, 1960 and 1965
(Million kwh)

	1960	1965
North	397.0	726.3
Dam Site (Mangla)	1.8	112.0
Total North	398.8	838.3
Upper Sind	-	4.0
Lower Sind	14.0	76.0
Karachi	163.4	403.7
TOTAL	576.2	1,322.0

3.21 From the above Table 10 it can be seen that in 1960, 70 percent of the industrial sales were in the North, 27 percent in Karachi and 3 percent in the Upper and Lower Sind. By 1965, the North's percentage of total sales had declined to 63 percent while Karachi's and the Sind's shares of the total had increased to 31 percent and 6 percent, respectively. These figures reflect the trend toward increasing industrialization in the South.

3.22 Industrial production appears to have been growing more rapidly in Karachi and the Sind than in the rest of the Province. Also industrial growth there appears to have been rather more power intensive than in the North where it has centered mainly on agricultural processing and consumer goods industries. Moreover, industrial sales in the North in 1964 and 1965 were somewhat curtailed by insufficient utility generating capability.

3.23 In the Upper Sind before the 25-mw steam station and associated transmission lines came into operation in 1965, almost all industries supplied their own electric power. In addition to some agriculture-related plants there were a cement plant and a railway repair shop at Sukkur. The Government is attempting to encourage industry to grow in the area by declaring tax holidays and establishing industrial parks. Esso Eastern Oil Company is constructing a fertilizer plant on the western edge of the Mari gas field. In addition, at the end of 1965, the Government had sanctioned 16 new industries for the area.

3.24 The Lower Sind has had an interconnected electric power system for a number of years. Industry in recent years has grown rapidly and at times faster than the power systems could supply it. As the power system expanded, its capacity was quickly absorbed and industry had to wait until more capacity was added. In 1963, one year when an adequate amount of power was available, electricity consumption increased by 28 percent. In 1965 there were 32 industries in operation and 70 more were sanctioned by the Government. Of the 32 existing industries, 24 were agriculture related; these included textile mills, cotton gins, flour mills and food processing plants. In addition there were a cement plant, a tannery, a glass factory and a number of small plants.

3.25 At the time of Partition Karachi had 41 industrial establishments; by 1965 the number exceeded 4,500. Many of these enterprises had to install their own generating equipment because the KESC system could not meet the demand in the early years. Much of the growth in electricity sales by KESC in recent years stems from the transfer of these industries to public supply. In 1965 the largest industrial demand for energy in Karachi was from textile plants; the remainder came from the Karachi shipyard, a steel company and a large number of smaller industries. The future trend is expected to be toward heavy industry including a large petrochemical complex, a steel mill, a machine tool manufacturing plant, and fertilizer plant expansions.

Bulk and Other Uses

3.26 Most of the bulk consumption is in the North where WAPDA supplies energy to various utilities for resale, to the Wah Ordnance Factory, to Government institutions, to railroads and to industrial estates. Street lighting is a relatively minor user of electricity. The sales to bulk consumers and for street lighting for the Province as a whole are shown for 1960 and 1965 in the following table.

Table 11

Sales to Bulk Consumers and Street Lighting, 1960 and 1965
(Million kwh)

	1960	1965
Bulk Sales	107.8	191.0
Street Lights	8.2	25.0
	116.0	216.0

Agricultural Pumping

3.27 Pumping groundwater for irrigation with tubewells is concentrated in the North where both the Government and private owners have undertaken extensive programs. Small numbers of wells are located in the Upper Sind and in the vicinity of Karachi. The sales for tubewell pumping have grown rapidly since 1960, from a level of about 85 million kwh to well over 500 million kwh by 1965. The average annual increase in sales in the 1960-65 period was 43 percent per year. The sales in the various areas are given in the following table.

Table 12

Agricultural Pumping Sales
(Million kwh)

	1960	1961	1962	1963	1964	1965
North	86.7	123.8	222.2	379.7	470.4	529.0
Upper Sind	-	0.4	0.5	1.6	2.0	3.0
Karachi	-	-	-	-	4.0	6.0
	86.7	124.2	222.7	381.3	476.4	538.0

3.28 A breakdown of the sales in the North for Government and private agricultural pumping is given below.

Table 13

Sales in the North for Government & Private Agricultural Pumping
(Million kwh)

	1960	1961	1962	1963	1964	1965
Government	49.0	72.1	157.3	203.7	236.3	285.0
Private	37.7	51.7	64.9	176.0	234.1	244.0
	86.7	123.8	222.2	379.7	470.4	529.0

3.29 The Government wells have an average capacity of about 3.0 to 3.5 cusecs; tubewells installed by farmers are generally about one cusec in capacity. The number of private electrified tubewells installed and in operation each year prior to 1965 is not known accurately. The number of Government tubewells connected in the five-year period July 1, 1960 to June 30, 1965 was about 2,000 and varied widely year by year. The number of Government and private electrified tubewells in the North, the Sind and near Karachi in operation in 1965 was estimated by the power consultant to be as follows:

Table 14

Estimated Number of Electrified Tubewells in 1965

	North	Sind	Karachi	Total
Government, Fresh	1,900	100	-	2,000
Government, Saline	-	15	-	15
Private, Fresh	12,250	-	400	12,650
	14,150	115	400	14,665

3.30 Since 1961, pumping at government-owned wells has been interrupted for two hours at the time of daily peak. This resulted in a reduction in peak demand of increasing amounts. The private wells were not interrupted, although there has been a large number of shutdowns during the recent power crisis. Pumping reaches a seasonal peak in the winter. The following table shows the composition of the December pumping demand and the amount of the reduction resulting from the two-hour shutdown of government wells.

Table 15

Reduction in Peak Demand Resulting from Interruption
(Megawatts)

	1960	1961	1962	1963	1964
Government Pumps	8	9	24	22	24
Private Pumps	4	6	12	34	42
Total	12	25	36	56	66
Reduction at Peak	0	0	12	13	14
Net Pumping	12	25	24	43	52

Loses and Unaccounted For

3.31 Losses and theft have increased substantially in the past five years in the North. From 1960 to 1965 losses increased from about 17 percent to about 20 percent reaching a peak of 22.5 percent in 1962. The high losses are partially the result of the long distances over which power is transmitted and of inadequate distribution facilities. Lack of proper metering, meter failures and illegal diversions add substantially to the losses and unaccounted for. In Karachi, the losses have averaged about 12 percent, but of course KESC, with its relatively compact system, does not have comparable lengths of transmission or amounts of transformer capacity to contend with.

IV. FORECASTS OF ENERGY REQUIREMENTS AND POWER DEMANDS

4.01 The load forecast plays a critical role in planning the development of the electric power system in West Pakistan. The growth of the system is expected to be so large that the size of the margin of error itself can greatly influence the amount of generating capacity that must be added to meet the loads of some given date. Beyond this purely physical point of view, the load forecast adopted has important economic and financial implications for system planning , as pointed out in Chapter I.

4.02 The Bank Group believes that it is right to adopt a 20-year load forecast as a basis for planning. Given that as much as four years may elapse in Pakistan between a definite decision to add thermal capacity and the completion of the installations, a five-year load forecast is the minimum that is adequate to ensure the physical availability of capacity to meet loads. Given the context of Pakistan planning, a ten-year load forecast is the minimum that is adequate to ensure that the correct decisions about the type, size and location of any significant new installation may be taken as well as about its most economic integration into the system. Given the substantial hydro developments an even longer perspective -- a 20-year load forecast -- should be adopted if the right decisions about installation are to be taken and if the potential of other projects is to be correctly assessed.

4.03 Both Mangla and Tarbela, for instance, have capabilities at full development that far exceed the 1967 peak of about 500 mw on the Northern Grid. Critical questions are when the units should be installed at each plant, whether and when thermal capability will be required to firm them up, and what amount of energy will be available from them for long-distance transmission to areas outside the Northern Grid system. The 20-year load forecast can thus have considerable relevance to early decisions regarding matters such as dam design, transmission-line investment and the interim installation of thermal capacity. To enable correct decisions to be reached on these matters, reasonable estimates are needed for a 20-year period not only of peak loads but also of energy requirements and of the regional distribution of loads.

Stone & Webster Forecast

4.04 For the purpose of their load forecast Stone & Webster divided West Pakistan into the five areas previously described (paragraphs 2.10-2.15) -- the large Northern Grid area, the Upper Sind centered on Sukkur and Khairpur, the Lower Sind or Hyderabad area, Karachi or the service area of KESC, and the extensive but very sparsely populated area of Baluchistan (Civil Divisions of Quetta, Kalat and Lasabela).

4.05 Stone & Webster's load forecasts were divided into two main portions: basic loads and agricultural pumping loads. Forecasts of the agricultural pumping load were made by IACA, the irrigation and agriculture consultants, with the assistance of Stone & Webster. Because IACA had not completed its studies by the time Stone & Webster were ready to begin compiling their forecasts, only preliminary estimates of the amount

of pumping were available. As will be seen, the difference between the preliminary and final estimates of pumping requirements was fairly large.

4.06 Stone & Webster projected requirements of electric energy for various classes of consumers in the key years 1970, 1975, 1980, and 1985. Annual hours of use were assigned to each class of consumers in each of the areas noted in paragraph 4.04 to derive the peak demand of each class. Class demands were totaled and a diversity factor was applied to obtain total area demand. Monthly energy requirements and peak loads were derived for the key years. This was done on the basis of the existing pattern of demand with consideration to likely changes in the pattern resulting from the growth of tubewell load, the increasing use of air-conditioning and the diminishing relative weight of the industrial load. Loads were then interpolated between years to arrive at a detailed monthly picture of energy requirements and peak loads for each area and for each month of the 20-year planning period. In all their calculations, Stone & Webster followed U.S. Federal Power Commission techniques, as required by their terms of reference and used loads net of station use. Because station use differs so much between thermal plants (about 5 percent of capacity) and hydro plants (about 0.5 percent of capacity) the use of gross demands could lead to exaggeration of the projected loads in later years when the system is more heavily hydro-based. Stone & Webster also used, for their base year, estimated figures for 1965 which contained no curtailment owing to load shedding (see para 3.06).

Residential Forecasts

4.07 As Stone & Webster did not have historical records of residential consumption on which to base their projections to 1985, they had to devise a method from material available. That method is briefly described in the paragraphs which follow.

4.08 From data supplied by WAPDA and by field checks Stone & Webster estimated the number of electrified houses and obtained an approximate idea of the amount of energy used per house in the territory served by WAPDA (see para 2.09). For this purpose Stone & Webster also made use of socioeconomic surveys of six large cities which provided information on the number of occupants per house, types of houses, wage levels and the degree of electrification.

4.09 Using the updated 1960 Housing Census and the updated 1961 Census of population, Stone & Webster calculated the number of persons per house in 1965. They concluded that about 10 percent of the population of West Pakistan or five million people (5 percent of the rural population and 34 percent of the urban population) had electricity in their houses in 1965.

4.10 Stone & Webster then made a population projection broken down into urban and rural components using an average overall growth rate of 2.75 percent per year, but an urban growth rate which averaged about 5.3 percent. The results of this projection are shown below:

Table 16

Population Projection of West Pakistan
(Thousands of People)

	1965	1970	1975	1980	1985
Urban	9,960	12,950	16,800	21,700	28,000
Rural	41,240	45,750	50,500	55,300	60,200
TOTAL	51,200	58,700	67,300	77,000	88,200
Percent Urban	19.5	22.1	25.0	28.2	31.7

On the basis of this projection the consultant then estimated the number of houses there would be in each of the key years, 1970, 1975, 1980 and 1985.

4.11 After establishing a customer/house ratio, Stone & Webster estimated what proportion of houses might be expected to be electrified by each key year. The numbers of residential customers (connected meters) expected to be served in the WAPDA territory and in Karachi are shown below:

Table 17

Number of Residential Customers
(Thousands)

	1965	1970	1975	1980	1985
WAPDA	577	1,010	1,616	2,360	3,228
KESC	90	137	200	290	405
	667	1,147	1,816	2,650	3,633

The gradual growth of electricity consumption per house was also projected on the basis of estimated use in 1965. This forecast is shown in the following table, on a per customer basis.

Table 18

Electricity Consumption Per Customer
(kwh per year per customer)

	1965	1970	1975	1980	1985
North	465	510	583	676	800
Sind & Balûchistân	518	593	655	732	802
Karachi	1,230	1,490	1,850	2,258	2,765
Average for West Pakistan	573	634	730	857	1,020

4.12 Multiplication of the number of electrified houses in each area by the projected average annual consumption per house gave a figure for total residential consumption in each area in each key year.

Table 19

Total Residential Consumption in Key Years
(Million kwh)

	1965	1970	1975	1980	1985
North	243	462	833	1,380	2,180
Sind and Baluchistan	28	61	122	234	400
Karachi	111	204	370	655	1,120
Total West Pakistan	382	727	1,325	2,269	3,700

4.13 On this basis, Stone & Webster expects that residential electrification, available to 10 percent of the population in 1965, will be available to about 34 percent of the population by 1985. During the same period average annual use per house would rise from about 510 kwh to about 1,070 kwh in the Northern cities, from about 1,090 kwh to about 2,240 kwh in Karachi, and from about 110 kwh to 250 kwh in the rural areas.

4.14 Reflected in these forecasts is the consultant's belief that income will rise to levels that will enable families to consume electricity in the amounts estimated and that the cost of electric service will decrease in the future as average use goes up. At present the average cost per residential customer is 21.5 paisas (US cents 4.5) per kwh in the WAPDA area and 16.0 paisas (US cents 3.3) per kwh in Karachi. The residential rates are, thus, somewhat higher in the WAPDA service areas than in Karachi, but in Karachi the prospective customer has to pay the entire capital cost for connections over 100 feet from the nearest line. The total capital cost including wiring for a small dwelling, would average about PRs 400; this is a large amount for the average worker. WAPDA does not charge for connection but adds a meter rental to the monthly bill which relieves the customer of the initial capital outlay. The rental fee is, however, without termination. The lowest bracket in the rate schedule in Karachi is 8.75 paisas (US cents 1.8) per kwh, whereas the WAPDA minimum is 12 paisas (US cents 2.5).

4.15 The Bank Group reviewed Stone & Webster's residential load forecasts and, in the process of doing so, tried to develop the outline of a procedure for integrating residential load forecasting more closely with overall economic planning in West Pakistan. Stone & Webster, as described above, broke down the growth of residential load into two component parts -- growth of the number of electrified houses and growth in the average consumption per house. The Bank Group tried to go one stage further by distinguishing between old and new customers in each five-year period and their respective average levels and rates of growth of consumption. The Bank Group's analyses are described more fully in Annex 2 to this volume.

4.16 The growth of residential connections will depend chiefly on three factors -- the growth of family incomes, the availability of electricity in new areas and the ability of the utilities to make new connections. It will also be affected by the way in which charges are levied for new connections, as the difference between the current situations in the WAPDA and KESC service areas makes clear. Availability of electricity in rural areas will depend mainly on expansion of the tubewell program and on the funds and personnel assigned to rural electrification. Apart from this the potential for increase of customers, whether in rural or urban areas, will depend heavily on the growth of incomes. Despite the evidence cited in para 3.15 that a substantial proportion of existing residential consumers has very low incomes, the Bank Group thinks that, for planning purposes, a reasonable 'household' income for new residential electrification is a monthly family income of PRs 200. Families achieving this income level should before long be able to meet the costs of housewiring, some elementary appliances, and a monthly electricity bill. The relatively high level of electrification observed among some of the poorest families in the Northern towns at the present time seems to be correlated with very high density living in old townhouses electrified in the past. This may therefore be a characteristic of the past situation which is not a good guide to the potential for new electrification. On the basis of a 'threshold' monthly family income of PRs 200 it is possible to identify from Table 8 a 'backlog' of urban families having already incomes above this level who should be able to meet the costs involved in consumption of electricity at home. This backlog is relatively small in the WAPDA area but large in Karachi (probably because of the initial connection charge there). On the basis of the 'threshold' income concept together with the growth of family income implied by the Perspective Plan, tentative projections can be made as to the amount of residential electrification implicit in the Perspective Plan. The Plan envisages approximately a doubling of family incomes between 1964/65 and 1984/85.

4.17 The fact that most of the families who will be newly connected to the electric power system in coming years will apparently be only just above the threshold income level, suggests that their initial consumption level will be low, perhaps about 200-250 kwh per year, enough to support a light bulb or two and an iron, radio or fan. The rate of growth of a family's consumption of electricity depends on the amount it can invest in electricity consuming appliances. Initially it may be quite high, as relatively inexpensive appliances are added. But the average rate of growth of consumption by established consumers will probably be substantially less because of the high price of many appliances and the length of time it will consequently take to accumulate them. Many of the heavy consumers of electricity, such as air-conditioning units, are so expensive that they cannot be expected to become widespread for a long time.

4.18 The Bank Group drew a number of conclusions from these studies (for detail see Annex 2). On an income basis, assuming the general income and income distribution targets of the Perspective Plan to be achieved, the number of residential consumers might grow somewhat more

rapidly than Stone & Webster had projected. This would be the case in Karachi and also in rural areas, given the wide coverage that the distribution system should have in later years as a result of the tubewell program. However, the Bank Group's studies also suggested that current average levels of consumption per household were somewhat below those suggested by Stone & Webster and that they might grow in future rather more slowly, especially in the early part of the Perspective Plan period. As regards rural electrification, Stone & Webster's targets were already quite ambitious, implying that West Pakistan would have a much higher level of rural electrification by 1985 than now exists in countries with income levels comparable with what West Pakistan should then achieve. The tubewell program would give West Pakistan a marked advantage over other countries in this regard; nevertheless, extension of electrification to all rural families in the 'eligible' income groups living in tubewell areas would represent a very large financial burden for WAPDA. As regards the overall residential load in the Province, the Bank Group concluded that Stone & Webster's projection was reasonable, though perhaps somewhat high, especially in the early part of the Plan period, as a result of the rather rapid early increase in average consumption per household they had projected.

Commercial Sales Forecast

4.19 It was explained earlier that forecasting of commercial loads is made difficult by the lack of records which distinguish commercial sales clearly from other categories. For the WAPDA areas, however, the power consultant found that two of the three accounting divisions in the North had kept statistics covering commercial and residential sales separately for all months of 1964. By using ratios based on these two divisions, WAPDA's commercial sales were estimated for 1965. The commercial sales in Karachi were determined from KESC's billings. The Stone & Webster forecast of commercial sales to 1985 is shown below.

Table 20

Commercial Sales Forecast
(Million kwh)

	1965	1970	1975	1980	1985
North	60	140	262	460	760
Sind and Baluchistan	14	35	77	138	243
Karachi	68	149	294	535	900
TOTAL	142	324	633	1,133	1,903

4.20 The annual use per customer is expected by Stone & Webster to vary widely. As the WAPDA territory includes all of the rural areas and as Karachi is entirely urban, a higher consumption in Karachi is to be expected. The following table shows the estimated annual use per customer in the various areas.

Table 21

Annual Use per Customer
(kwh per year per customer)

	1965	1970	1975	1980	1985
North	1,395	1,890	2,220	2,720	3,333
Sind & Baluchistan	1,077	1,346	1,638	1,663	1,869
Karachi	2,267	3,239	4,455	5,750	6,920
Average West Pakistan	1,651	2,219	2,740	3,281	3,900

Combined Residential & Commercial Sales Forecast

4.21 The power consultant combined residential and commercial classifications into a 'General Sales' category. The average rate of growth of sales in this classification was forecast to be about 14 percent per year. The annual use per general customer was forecast to increase from 536 kwh in 1965 to 1,360 kwh in 1985. The sales forecast is given in the table below for the Province as a whole.

Table 22

General Sales Forecast
(Million kwh)

	1965	1970	1975	1980	1985
General Sales	524	1,051	1,958	3,402	5,603

Industrial Forecast

4.22 Stone & Webster forecast that the industrial use of electricity would increase at a rate somewhat over 13 percent between 1965 and 1975 and then increase at a slower rate averaging about 9 percent between 1975 and 1980 and about 8 percent between 1980 and 1985. By 1985 industrial sales would account for over 50 percent of the total sales.

4.23 Stone & Webster projected a continuation of the trend away from self-generation by diesels in industry towards purchase of power from the utilities as the distribution system is extended, but, nevertheless foresaw a gradual growth in the total amount of energy generated in industrial plants. There are certain loads, such as the load of the projected Karachi Steel Mill, which probably could not be completely absorbed by the utilities in the early years. Moreover, there are many industries -- especially petrochemicals and fertilizer, which are expected to make important contributions to industrial growth in the Province -- which use process steam in their manufacturing and might therefore readily pass the steam initially through an extraction turbine and produce cheap power. Industrially owned generation would, in 1985, comprise 4 percent of the total.

4.24 Industrial sales in the Northern area are expected to be principally to agriculture-related industries such as food processing,

to textiles and other light industries, and to some more power-intensive industries such as cement. The most important single demand on the WAPDA system in the North has in recent years been for construction power for the Mangla Dam. As this demand declines, the demand for construction power for the Tarbela Dam is expected to increase and to reach a peak of about 220 million kwh in 1970, then decline to zero in 1976. No other major demands for construction power are set out separately in the estimates.

4.25 In the Upper Sind, industry is somewhat agriculture related but is expected to become more diversified in the future. The fertilizer plant which Esso Eastern Company is constructing near the Mari gas field is expected to purchase part of its requirements from WAPDA after 1970. Because fertilizer production is expected to double or triple in the next 20 years, WAPDA's electric sales in this area as projected by Stone & Webster would increase substantially.

4.26 Industrial consumption of energy is forecast to grow more rapidly in the Karachi-Hyderabad area than in the North. The trend is expected to be toward heavy industry, including the large petrochemical complex now under construction, the steel mill and other power intensive industries. By 1985 Karachi's proportion of total industrial sales of electric energy is projected by Stone & Webster to be 47 percent and the North's proportion 40 percent as opposed to 31 and 63 percent respectively in 1965.

4.27 Industrial sales forecast of Stone & Webster for the various areas is given in the following table.

Table 23

Stone & Webster Forecast of Industrial Energy Requirements
(Million kwh, net of station use)

	1965	1970	1975	1980	1985	Annual Rate of Growth (%)
Northern Grid a/	820	1,410	2,270	3,480	5,030	9.5
Upper Sind	10	145 b/	220 c/	300	409	20.0
Lower Sind	83	204	420	720	1,130	14.0
Karachi	355	850	1,750	2,950	4,440	13.5
Quetta	3	14	24	40	60	16.1
Self-generation	544	650	915	1,000	1,103	3.6
Karachi Petrochemical	-	130	480	920	1,390	
Subtotal	1,815	3,403	6,079	9,410	13,562	10.5
North: Dam sites	138	220	30	-	-	
TOTAL	1,953	3,623	6,109	9,410	13,562	

a/ Excludes consumption at dam sites, but includes an annual item of 30 million kwh which the power consultant estimated as the past and future supply of the Wah Ordnance Factory and included in the Bulk classification.
b/ Estimate assumes WAPDA would serve Esso fertilizer factory in 1970 with 100 million kwh at maximum load of 15 mw.
c/ Forecast based on power consultant's anticipation of substantial expansion in the fertilizer, cement, textile and food processing industries.

4.28 The Bank Group attempted to test the industrial load forecast on the basis of the Perspective Plan. A detailed Provincial plan was still under preparation at the time the power consultant and the Bank Group were making their studies. The information that was made available to the Bank implied that the average annual growth rate of industrial production over the 20-year period was expected to be about 8 percent, which is substantially lower than the average annual rate of about 16 percent at which West Pakistan's industrial output grew in real terms during the Second Plan period.

4.29 As discussed in more detail in Annex 3, so that uncertainty regarding the future may be allowed for, the Bank Group assumed a rate of growth for industrial output higher than that implied by the Planning Commission's framework. Because of the importance of the cement and fertilizer industries in West Pakistan, both of high power intensity, separate projections for these two industries were made. Then a series of exercises were undertaken in full recognition that owing to the weakness of the statistical base in West Pakistan and the relative newness of the techniques adopted, the results must be regarded as tentative. Nevertheless, the Bank Group feels that these exercises do afford some basis for judgment on the validity of Stone & Webster's forecasts.

4.30 The Bank Group attempted to analyze the relationship between industrial value added 1/ and the growth in industrial use of electricity. On the basis of information supplied by the Planning Commission and other material gathered by the power consultant, the Bank Group estimated the amount of electricity consumed by each major industrial sector (food, textiles, chemicals, machinery, etc.) and the net output of each sector in millions of rupees at factor cost. From these data the power intensity (kwh per PRs 10 value added) of each industry in each sector was calculated for a base year (1964/65). The following table gives the Bank Group's estimate of electricity consumption and power intensities for each major industrial sector. The figures for large scale manufacturing, however, do not present a picture of total industrial consumption of electricity in the Province as mining and small-scale industry are not included. With the addition of the consumption of these industries, a figure closely comparable with the power consultant's 1964 figure of 1,680 million kwh is obtained, especially if the consumption of the Wah Ordnance Factory of 30 million kwh is added to the consultant's total. (Stone & Webster included the Wah consumption in the Bulk category. The Bank Group included it in the Industrial Category).

1/ Value added is defined here as output at factor cost, net of intermediate purchases.

Table 24

Consumption of Electricity by Large-Scale Manufacturing in West Pakistan: Estimated Power Intensities, 1964/65

	Value Added (Million PRs)	Estimated Power Consumption (Million kwh)	Power Intensity (kwh/PRs 10 Value Added)
Capital goods	507	230	4.53
Consumer goods	1,408	680	4.82
Cement, concrete products	56	212	37.90
Nitrogen fertilizer	29	126	44.30
Other intermediates	670	235	3.50
	2,670	1,483	5.55
Mining	134	24	
Small Industry	1,071	210	
	3,875	1,717	

4.31 The above figures may be compared with the actual consumption figures for WAPDA for the fiscal year 1964/65 plus estimates for KESC and other utilities in the Province; the table below gives the details.

Table 25

Estimated Industrial Consumption of Electricity 1964/65

WAPDA a/ - Industrial Sales	902
Deduction - estimated consumption at dam sites	120
	782
KESC b/ - Industrial Sales	325
Individually-owned generators c/	544
Other utilities' industrial sales c/	45
TOTAL	1,696

a/ Taken from WAPDA's annual reports and including estimated sales to Wah Ordnance Factory.

b/ Interpolated from KESC's recorded sales (calendar year basis) to large industry and to small industry.

c/ Estimates based on Central Statistical Office, Census of Electricity Undertakings, 1962/63 and power consultant's report.

4.32 For purposes of projection, the Bank Group made certain assumptions about the overall power intensity structure of industry in West Pakistan and about future changes, either within industries or resulting from the growing importance of industries having a different power intensity

from the prevailing average. It had to decide what effect changes of this sort would have on the regional load distribution. Using the assumed growth rate in industrial output it calculated energy requirements by key years and made some estimates as to its likely regional distribution.

4.33 The results are presented below; for the sake of comparison, Stone & Webster's forecast of industrial requirements (including self-generation) is also shown. The Bank Group's figures are for fiscal years, e.g. 1969/70, one half year ahead of the calendar years, e.g. 1970, to which the Stone & Webster figures refer.

Table 26

Bank's and Consultant's Forecasts of Industrial Energy Requirements a/
(Million kwh)

	1964/65	1969/70	1974/75	1979/80	1984/85
Bank Group	1717	3460	5650	8520	12,800
Stone & Webster	1815	3403	6079	9410	13,562

a/ Excluding dam sites.

4.34 In very general terms the Bank Group reached the conclusion that, while Stone & Webster's industrial load forecast may err on the high side, it is not too far out of line. The Bank Group felt that the rapid rate of growth in industrial load projected for the Third Five Year Plan by the consultant may be attained, largely as a result of concentrated development in a number of very power-intensive industries such as fertilizer, petrochemicals, and cement. Thus, during the Third Plan period, total industrial load may well grow more rapidly than total industrial output. This will be in contrast to the Second Plan period when total industrial load grew at an average rate of about 12 percent per annum while output of large-scale industry (in real terms) grew at an average rate of about 16 percent per annum. On the other hand, during the Fourth Plan period the growth of industrial demand for electricity may slow down as industrial growth stabilizes somewhat and agriculture grows more rapidly, and as some of the most power-intensive industries such as fertilizer take advantage of modern techniques relying less on purchase of electricity and more on generation from process steam. The same trend might continue through the Fifth Plan period.

4.35 Economic studies undertaken in the Bank tend to confirm the general judgment of Stone & Webster that the load will grow more rapidly in future in the South (Karachi and the Sind) than in the North where it is at present larger. This is because few power-intensive industries are presently foreseeable in the North, whereas Karachi has all the advantages of being the major port of the country and having the relatively highly developed industrial infrastructure which is most crucial to the success of modern industry. The Sind benefits from its extensive natural gas resources, and also from its convenient location relatively close to the port of Karachi and midway between the country's major markets, the

Punjab on the one hand and Karachi and the export market on the other. This is not to say that industrial development will be slow in the North but that it will be mainly concentrated in consumer-goods industries and agricultural processing industries which are not major consumers of power. Even the machinery complexes planned for the North do not compare in their power requirements with some of the major industries planned for the South.

4.36 Within the South there might be some redistribution of the loads projected by Stone & Webster. The consultant appears to allow a growth of industrial load in the Upper Sind barely sufficient to meet the demands for purchased power that may arise from the fertilizer industry there. On the other hand Stone & Webster has allowed high growth rates for the more established industrial area around Hyderabad, and some of the fertilizer production might take place there, depending on the choice of gas field for use in fertilizer production and on the extent to which economic reasons make it mandatory to locate production on the gas field itself. The petrochemical load which Stone & Webster project for Karachi appears a little high in comparison with some of the more detailed planning undertaken more recently. On the other hand latest plans do envisage some railroad electrification in the South which would add a small additional load not included in the power consultant's load forecast.

Agricultural Pumping Forecast

4.37 When Stone & Webster were making their agricultural pumping forecast they used, as a basis, preliminary material prepared by IACA. This covered drainage and crop-water requirements, a schedule of tubewell projects, and a pattern of integrated use of groundwater and surface water deduced from computer studies. The irrigation engineers also determined pumping utilization factors for different types of wells in different areas in order to assess peak load per tubewell and estimated a diversity factor to be applied to the aggregation of tubewell loads in an area. In order to reduce the system peak at critical times, an allowance was made for interrupting tubewells during the four-hour evening peak periods. The assumption made for the purposes of the load forecast was that public wells in saline areas could all be shut down throughout the four-hour period while public wells in usable groundwater areas could be partially shut down, 35 percent for the first two-hour period and another 35 percent for the second two-hour period.

4.38 On the basis of this preliminary material, which envisaged that public and private tubewells would increase from 14,265 in 1965 to 121,500 in 1985, Stone & Webster estimated that energy sales for pumping would increase from 579 million kwh in 1965 to 5,224 million kwh in 1985. The rate of growth of pumping requirements was estimated to increase rapidly until 1975 and then grow at a declining rate. The following table gives Stone & Webster's estimated growth rates for Government and private pumping requirements.

Table 27

Average Annual Growth of Pumping Requirements
(Percentages)

	1966-70	1970-75	1975-80	1980-85
Government	19.4	17.1	7.5	3.3
Private	11.9	13.3	8.9	3.7
Total Pumping	16.7	15.8	8.0	3.4

4.39 Stone & Webster's sales forecast for pumping in the various areas is given below; agricultural pumping in 1965 was concentrated in the North but is expected to expand into the Sind.

Table 28

Stone & Webster's Agricultural Sales Forecast
(Million kwh)

	1965	1970	1975	1980	1985
North					
Government	305	740	1,634	2,340	2,753
Private	262	460	861	1,320	1,581
Upper Sind					
(Gov't. & Pvt.)	3	275	584	705	805
Baluchistan (Private)	-	2	5	9	15
Karachi (Private)	6	11	14	19	25
Total Sales	576	1,488	3,098	4,393	5,179
Pumping Losses	114	327	677	842	976
Total Requirements	690	1,815	3,775	5,235	6,155

4.40 The power consultant emphasized that by proper control, the publicly owned wells could be shut down daily as noted above, and this could result in a reduction in demand at the time of the system peak by fairly substantial amounts. The table below shows the gross pumping demands, the reductions which would result from a two-hour shutdown and the net demands.

Table 29

Pumping Demands 1965-85
(Megawatts)

	1965	1970	1975	1980	1985
Gross Demand	134	366	739	1,014	1,252
Reduction	25	61	115	162	192
Net Demand	109	305	624	852	1,061

4.41 Stone & Webster commented that a major constraint to the installation of the number of tubewells envisaged by IACA might be the inability of WAPDA to expand its distribution systems rapidly enough to electrify the proposed number of tubewells.

4.42 After Stone & Webster completed their report, IACA carried the studies further and made considerable revisions to the forecast of tubewell pumping load. There were two important aspects to the revisions. In the first place, as the agriculture consultant firmed up the proposed development program,he came to much more definite conclusions as to the number of tubewells that would be required. This consisted of a substantial decrease in the total number of private and public wells proposed for 1985; from the 121,500 noted in para. 4.38 to 67,100. The number of private and public electrified wells used by the power consultant as a basis for his estimates and the number finally estimated and projected into the future by IACA are shown in the table below for key years (excluding wells in Karachi).

Table 30

IACA's Original and Revised Projection of Electrified Tubewells

	(Number of Tubewells) 1965	1970	1975	1980	1985
IACA's Revised Program					
Private	9,000	17,000	24,000	18,000	23,000
Public Fresh	2,200	9,500	19,800	32,200	34,300
Public Saline	-	-	200	4,500	9,800
TOTAL	11,200	26,500	44,000	54,700	67,100
IACA's Original Program					
Private	12,250	27,150	49,050	70,150	88,350
Public Fresh	2,000	10,400	23,350	25,300	27,250
Public Saline	15	165	4,300	5,100	5,900
TOTAL	14,265	37,715	76,700	100,550	121,500

4.43 In the second place, final integration of the surface and groundwater programs recommended in IACA's report led to a much more refined notion of the optimum monthly pattern of tubewell loads. The monthly distribution of the pumping load was much improved by making it, to the degree possible given surface water supplies, higher in months when there was ample surplus hydro generating capacity available and lower in months when system capability is closest to system load.

4.44 The main effects of both these revisions were to reduce the estimate of energy required for pumping by about 20 percent by 1975 and also to reduce the peak loads. The Bank Group agrees with these revisions. The following table shows the major changes in the projected pumping loads introduced by the irrigation consultant. The changes have noticeably different effects on the development of loads in the Northern Grid and Sind.

Table 31

Comparison of Original and Revised IACA Programs

a) IACA Program Given in Stone & Webster's Report

	1965		1975			1985		
	Energy	Peak	Energy	May Peak	Pumping Peak	Energy	May Peak	Pumping Peak
North	680	109(Sep)	3,044	448	561(Oct)	5,157	710	976(Sep)
Sind	4	1	712	71	116(Feb)	958	95	140(Mar)
			3,756	519		6,115	805	
Critical Year Addition				0			219	
				519			1,024	

b) IACA's Revised Program of July 1966

	1965		1975			1985		
	Energy	Peak	Energy	May Peak	Pumping Peak	Energy	May Peak	Pumping Peak
North	680	109(Sep)	2,628	327	521(Oct)	4,793	570	809(Oct)
Sind	4	1	388	43	54(Jan)	1,192	132	157(Oct)
			3,016	370		5,985	702	
Critical Year Addition				30			130	
				400			832	

NOTE:

All peak loads given in mw, net of interruptible. All energy figures in million kwh; they include losses. Peak load figures are given for May as well as for the peak pumping months because May will normally be the critical month, as far as generating capability is concerned, after completion of Tarbela Dam. "Critical year additions" refer to the additional capability required to meet pumping loads in years of low rabi surface water supplies.

Bulk and Other Uses

4.46 As mentioned before, the "Bulk and Other" classification includes sales to licensees and certain non-licensees for resale for local distribution, the railways, military establishments and other Government organizations and street lighting. For some of these items, Stone & Webster have made separate projections which cover identifiable prospective loads, such as sales of construction power for Mangla and Tarbela Dams, railway electrification and the load of Wah Ordnance Factory. They also cover classes which make up relatively small portions of the total load such as public lighting. For this last category, Stone & Webster applied a rate of growth somewhat above that experienced in developed countries.

4.47 Most of the bulk sales are supplied by WAPDA. These sales have been growing rapidly, but Stone & Webster projects that future growth will average about 7 or 8 percent. At this rate, this classification would account for only 5 percent of the total in 1985. The following table gives Stone & Webster's forecast for street lighting and bulk sales for the various areas.

Table 32

Forecast of Street Lighting and Bulk Sales
(Million kwh)

	1965	1970	1975	1980	1985
North					
Street Lights	17	25	35	47	62
Bulk	140	250	365	485	580
Sind and Baluchistan					
Street Lights	3	7	13	20	29
Bulk	5	10	14	20	28
Karachi					
Street Lights	5	7	10	14	20
Bulk	89	150	242	362	515
TOTAL	259	449	679	948	1,234

Losses and Unaccounted For

4.48 An important portion of WAPDA's total load in recent years has been transmission and distribution losses. It is estimated that on the Northern Grid system they rose from 17 percent of total energy generated in 1960 to a peak of about 22.5 percent in 1962. In 1964 they were about 20 percent of energy generated. Stone & Webster estimates that much of these losses, which are due to inadequate maintenance of the system, the bad state of the distribution network and illegal diversion of energy, can be eliminated by better management. Therefore, despite the greatly increased amount of long-distance transmission that will be involved in later years, it is estimated that losses and unaccounted for could fall to about 17.5 percent of total generation on the Northern Grid system by 1975 and to about 15.7 percent by 1985 and by similar amounts in the other WAPDA areas. They are already down to about 12 percent on the KESC system. For the country as a whole Stone & Webster assumed that losses and diversions could be gradually reduced from 19.4 percent in 1965 to 14.3 percent in 1985 and that diversions could be converted into sales in the future.

Summary of Stone & Webster's Forecast

4.49 The projections presented separately in the preceding pages led Stone & Webster to the following summary conclusions. Total net electric requirements will increase from a non-suppressed 3,933 million kwh in 1965 to nearly 30,000 million kwh in 1985. The average annual rate of increase over the 20-year period 1965-85 would be 10.6 percent per year, ranging from 14.8 percent during the Third Plan period to 7.0 percent in 1980-85. Industrial consumption of
kwh in 1965 to 13,500 million kwh in 1985, or at an average rate of 10.5 percent per year, falling from 13.0 percent in the Third Plan period to

7.6 percent in the period 1980-85. Residential consumption of electric energy would grow from about 380 million kwh in 1965 to about 3,700 million kwh in 1985 or at an average rate of 12.0 percent per year, falling from nearly 14 percent in the Third Plan period to about 10 percent in the period 1980-85. Agricultural consumption of energy would grow from about 576 million kwh in 1965 to about 5,179 million kwh in 1985 or at an average rate of 11.6 percent per year, falling from 21 percent in the Third Plan period to 3.3 percent in the period 1980-85. The details of this load forecast are summarized in the tables below.

Sales by Classes of Consumers

4.50 The sales forecasts to the various classes of consumers are summarized in the following table.

Table 33

Energy Sales by Public Utilities to Various Classes of Consumers
(Million kwh)

Class	1965	1970	1975	1980	1985
Residential & Commercial	524	1,048	1,958	3,401	5,603
Industrial a/	1,379	2,953	5,164	8,380	12,429
Bulk and Others	259	449	679	948	1,234
Agricultural Pumping	576	1,488	3,098	4,393	5,179
Total Sales	2,738	5,938	10,899	17,122	24,445
Losses and Unaccounted For	651	1,246	2,102	3,015	4,085
Total Utility Generation	3,389	7,184	13,001	20,137	28,530

a/ Exclusive of industrially owned generation.

4.51 The percentage of total sales of each class of service is given in the table below.

Table 34

Class of Service as Percent of Sales

	1965	1970	1975	1980	1985
General	19.3	17.6	18.0	19.9	22.9
Industrial	50.2	49.7	47.4	48.9	50.9
Bulk & Others	9.5	7.6	6.2	5.5	5.0
Agricultural Pumping	21.0	25.1	28.4	25.7	21.2
TOTAL	100.0	100.0	100.0	100.0	100.0
Losses a/	19.7	17.3	16.2	15.0	14.3

a/ The percentages relate to total sales and losses to total generation.

4.52 The maximum utility demand, derived from the estimated energy requirements, is shown in the table below. The demands of the industrially owned generation were not included as they were not obtainable with any reasonable degree of accuracy.

Table 35

Utility Demands

	1965	1970	1975	1980	1985
Utility Demand (mw)	650	1,337	2,372	3,771	5,437
Load Factor (%)	59.5	61.3	62.6	61.0	59.8

Final Forecast of Energy and Peak Loads

4.53 The impact of the reduction in pumping load which resulted from the irrigation consultant's further studies is apparent from comparison of Table 36 below with the foregoing tables. The most marked differences occur in 1975 and 1980 in each of which total energy requirements were reduced by nearly 1,000 million kwh. The change in the projection of peak load is not proportionate to change in energy requirements because of the difference between the two pumping load forecasts in the monthly pattern of tubewell pumping.

Table 36

Final Forecast of Energy Consumption (including losses)
(Million kwh)

	1965	1970	1975	1980	1985
Basic	2,705	5,374	9,245	14,932	22,415
Pumping	684	1,570	3,016	4,227	5,985
Subtotal	3,389	6,944	12,261	19,159	28,400
Industrially owned	544	650	915	1,000	1,103
TOTAL	3,933	7,594	13,176	20,159	29,503

4.54 The average estimated annual growth for five-year periods from 1960 through 1985 is shown below.

Table 37

Average Annual Growth Rates
(Percentages)

Period	Basic Req'mts. a/	Pumping Req'mts.	Total Net Generation
1960-65	15.4	47.0	18.4
1965-70	13.1	18.0	14.0
1970-75	10.9	14.0	11.6
1975-80	9.4	7.0	8.9
1980-85	8.1	7.2	7.9

a/ Including industrially owned generation.

Summary of Energy Generated and Demands by Areas

4.55 The following tables summarize the energy estimated to be generated by public utilities net of station use for the various areas in West Pakistan as forecast by Stone & Webster and adjusted for the final pumping estimates.

Table 38

Forecast of Energy Generated by Public Utilities a/
(Million kwh net)

Area	1965	1970	1975	1980	1985	Annual Rate of Growth(%)
North	2,480	4,606	7,228	10,589	15,063	9.5
Upper Sind	31	271	650	976	1,518	21.5
Lower Sind	152	349	778	1,405	2,309	14.6
Baluchistan	16	43	85	134	210	13.8
Karachi	710	1,675	3,520	6,055	9,300	13.8
TOTAL	3,389	6,944	12,261	19,159	28,400	11.2

Table 39

Forecast of Peak Loads on Public Utilities a/
(mw)

Area	1965	1970	1975	1980	1985
North	473	889	1,402	2,021	2,878
Upper Sind	8	45	105	162	250
Lower Sind	31	73	154	266	424
Baluchistan	5	12	22	32	48
Karachi	136	309	642	1,114	1,730
TOTAL	653	1,328	2,325	3,595	5,330

a/ Exclusive of industrially owned generation.

4.56 In 1965 about 73 percent of the total utility generation was consumed in the Northern Grid, and 21 percent in Karachi. By 1985 the Northern Grid is estimated to consume 53 percent of the total, and Karachi 33 percent. The pattern in 1985 reflects the expected development of industry in the South.

Stone & Webster's Lower-Level Forecast

4.57 Stone & Webster's forecast was prepared on the basis of the relatively optimistic growth rates of the Perspective Plan. For such growth rates to take place Stone & Webster pointed out that large sums of investment capital would be required; for the execution of the development programs envisaged, an expansion of skilled labor for farms and factories would also be required and more managerial talent would be necessary.

4.58 If there were insufficient capital to develop the heavy industry envisaged there would be a reduction in the demand for electricity particularly in Karachi. If the tubewell program should proceed at a slower pace than originally forecast, then village electrification would be reduced. If agricultural and industrial production have slower growth rates than projected, then the growth of family incomes would be less than the 84 percent predicted during the next 20 years. Lower family income would mean that fewer families could afford electricity.

4.59 The power consultant believes that the utility demand of 5,437 mw which he forecast is consistent with the targets of the Perspective Plan for 1985. For the cases where the Perspective Plan targets are not reached by 1985 he has made a lower level forecast, in which the projected demand of 5,437 mw would be reached in 1990 instead of 1985. In order to determine what effect this postponement would have on both the total and pumping demands, the power consultant plotted a curve of his higher level forecast of all demands, including pumping, and a curve for the pumping demand covering the period 1965-85. On the same chart he plotted curves of the two demands reaching the same ultimate levels five years later. From these two curves he approximated the amount of the reduction that would occur as shown in the table below.

Table 40

Reductions in Peak Demands
(Megawatts)

	1965	1970	1975	1980	1985
As forecast	650	1,337	2,372	3,771	5,437
Lower Level	650	1,186	2,000	3,000	4,100
Reduction	--	151	372	771	1,337
Reduction (%)		11.3	15.7	20.4	24.6

4.61 The reduction in the annual growth rates for five-year periods is shown below.

Table 41

Growth Rates with Lower Level Forecast
(Percentages)

	1965-70	1970-75	1975-80	1980-85
As forecast	16.1	12.1	9.7	7.6
Lower Level	14.1	11.0	8.4	6.4

Comparison with Short-Term Forecasts

4.62 While the Bank Group has, as described, made its own checks upon the validity of the Stone & Webster forecast over the full 20-year period, it thought it would be useful also to make a detailed survey of prospective loads for the Third and Fourth Plan periods since the load

forecast must, in this case, serve as the basis of an "Action Program" as well as a guide to long-term planning. The Bank Group made a comparison between Stone & Webster's forecast and short-term forecasts prepared by, or on behalf of, WAPDA and provided to the Bank Group by WAPDA first in November 1966 and with slight revisions in April 1967.

4.63 KESC has been making detailed short-term load forecasts for its area for some years, but the first comprehensive survey of the power market in the remainder of West Pakistan was carried out by Harza Engineering Company under the auspices of WAPDA in 1961/62. The results of the survey were published in a report entitled Power Market Survey and Forecasts of System Loads (June 1963). The survey attempted to give a comprehensive coverage of existing loads (whether on WAPDA, other utilities or supplied by self-generation), potential loads (i.e., including loads in existence but not yet electrified) and actual prospective WAPDA loads over a five-year period. Loads were built up item by item to give a comprehensive picture for each of the eleven Civil Divisions outside Karachi and they were then reassembled on a load-center basis. Most of the procedures now used by WAPDA for load forecasting were originally established during the course of this survey.

4.64 WAPDA set up its own Power Market Survey Organization (PMS) in 1963 and annual reports have been published since that time, often with considerable delay, updating the load forecast and extending it one more year so as to maintain the five-year perspective. These surveys group energy consumption into six main classifications: Residential and Commercial, Small Industry (less than 70 kw connected load), Medium and Large Industry, Agriculture, SCARPS (Government tubewell projects), Dam Sites and Losses. The loads are grouped on a Divisional basis, again by load centers, and finally aggregated by grid systems to produce five-year forecasts of annual peak demand for each of the four main WAPDA service areas.

4.65 Unfortunately, at least for comparative purposes, small industrial loads are grouped with residential and commercial loads and agricultural loads (both public and private pumping, except for SCARPS) are grouped with medium and large industrial loads. The installed capacity of prime movers and estimated peak-load experienced are used to assess probable demands of existing industries which are expected to be connected to the WAPDA system. Information about likely new industrial loads is obtained from Government sanctioning agencies and the industrialists responsible for the projects; sometimes it seems, insufficient selectivity is applied in the inclusion of these loads despite the historical evidence that sanctioned industries sometimes never materialize and often come to fruition more slowly than initially anticipated. In the absence of specific information, existing industrial loads like existing residential and commercial loads are increased at a rate of about 6 percent per annum for the purposes of the projection.

4.66 In the aggregation of industries and tubewells into settlements and of settlements into District totals, various diversity factors are used and a 14 percent allowance for distribution losses is added to District

totals. SCARPS, including their own somewhat lower allowance for losses, and a further seven percent allowance for transmission losses are then added. Further diversity factors are applied in the aggregation of loads into totals for each grid system. WAPDA's historical statistics on sales cannot easily be related to the figures used for the base year in the Power Market Surveys. The Surveys present the existing loads and load forecasts in a form that combines the different classes of load into a few very general categories. PMS also uses gross requirements (i.e., including station use) whereas Stone & Webster uses net figures.

4.67 These differences in concepts and classification severely limit the possibility of comparison; the most relevant comparison that seems possible is that between the rates of growth for the various main classifications of load given in the WAPDA reports and those implied by Stone & Webster. The following table presents from the 1965 Power Market Survey, the latest available at the time of writing, annual growth rates for 1964-69 for different classes of energy requirements which can be compared with the growth rates given in brackets in the summary of the Stone & Webster load forecast (Table 47).

Table 42

WAPDA's Power Market Survey Projections of Load Growth 1964-69

	Annual Average Rates of Growth (in %)				
	North	Upper Sind	Lower Sind	Quetta	Total d/
Industrial and Agricultural a/	16.5	85	41	60	20
Residential and Commercial b/					
Cities	8.0	26	8.0	19	8.6
Towns	12.7	41	11.8	47	14.1
Villages	17.0	60	18.8	46	17.8
TOTAL ENERGY c/	19.6	85	33	39	22.0

a/ Excluding SCARPS, dam sites and losses.
b/ Including Small Industry.
c/ Including SCARPS, dam sites and losses.
d/ Including Kalat.

4.68 Comparison reveals that the overall growth rates implicit in the Stone & Webster forecast for 1965-70 are lower in all four areas than the growth rates suggested by the WAPDA Power Market Survey. 1/ In the two

1/ To some extent the Stone & Webster growth rates are lower because of the difference in the (1964) base-year figures used. WAPDA's figures purport to be the actual loads supplied by the Authority in the base year, adjusted in the case of residential and commercial load for an eight percent allowance for required higher voltages. The Stone & Webster base-year figures include supplies from other utilities. This probably does not distort the comparison significantly except in the case of Upper Sind.

most significant areas, Northern Grid and Lower Sind, PMS has a growth rate of 19.6 percent against Stone & Webster's 13.0 percent and 33 percent against about 20-25 percent (including some Sind pumping), respectively. The divergence in the small load areas is even greater. The main differences in all these areas occurs on the industrial load; differences on the residential and commercial load are smaller, and Stone & Webster's projections are in fact generally higher for these groups. For the North WAPDA has a much higher growth rate for its agricultural and industrial category (16.5 percent) than Stone & Webster has for either its industrial category (11.4 percent) or private pumping (11.9 percent). For the Lower Sind WAPDA has a growth rate of about 40 percent in industrial and agricultural loads against Stone & Webster's 20 percent growth rate in industrial loads.

4.69 The relatively slight increase in residential loads projected by the Power Market Survey Organization is all the more striking when account is taken of the ambitious village electrification program which is said to underlie its forecasts. Electrification of over 60 towns (i.e, settlements of between 5,000 and 100,000 inhabitants) and of about 1,500 villages was projected in the PMS for the period 1965 to 1969. In the last year of the Second Plan period (1964/65) WAPDA electrified about 100 villages and in the first year of the Third Plan period about 200 villages were electrified so that the town and village electrification targets seem ambitious, though they may be attainable with a concentrated effort. Nevertheless WAPDA's projection of growth in residential and commercial load seems low, and this may result from the assumption of only a 6 percent rate of increase in existing "general" loads. WAPDA's residential and commercial sales in fact grew at an average annual rate of nearly 20 percent between 1960 and 1966.

4.70 As far as the scheduling of new capacity is concerned, the most important part of the load forecast is the projection of peak loads. Tables 43-45 present comparatively the several short-range load forecasts made by Harza and WAPDA and the Stone & Webster load forecasts for the three main WAPDA service areas. Table 43 for the Northern Grid area indicates that Harza's original forecast has so far proved remarkably accurate although it may have been slightly too low to cover the 1965 non-suppressed peak. If allowance is made for the fact that WAPDA's load forecast fails to make adjustment for interruption of tubewells even on annual peak days, then it is clear that the Stone & Webster forecast is slightly above the WAPDA forecast for 1966 and then gradually diverges until, by 1970, it is about 100 mw below the peak load projected in the draft of the latest PMS. Stone & Webster include private pumping as well as public pumping under tubewell load, and adjustment for this reveals that practically all of the difference between their load forecast and that of WAPDA's occurs in the basic load. Scrutiny of the PMS reveals that several discreet factors account for a substantial part of this divergence. WAPDA allows a peak load for Tarbela construction power of about 80-85 mw against Stone & Webster's 50-55 mw. 1/ WAPDA also allows 5 mw for further work at Mangla,

1/ The amount of power required for the construction of Tarbela will not become clear until the main contract is finally let. WAPDA's estimate is based on the assumption that the contractor will make extensive use of power-driven conveyor belts for transporting dirt and rockfill. Stone & Webster point to alternative construction methods and state that their estimate represents an "intermediate situation".

Table 43

Comparative Load Forecasts,[a] WAPDA Northern Grid System
(mw)

	Harza, June 1963			PMS July, 1964	PMS, July, 1965			PMS, July 1966			ACTUAL			Stone & Webster[c]			
	Basic	Public Tube-wells	Total	Total	Basic	Public Tube-wells	Total	Basic	Public Tube-wells	Total	Basic	Public Tube-wells	Total	Basic	Tube-well	Inter-ruption	Total
1961	197	5	202								197	5	202				
1962	239	21	260								239	21	260				
1963	298	25	323								304	22	326				
1964	358	35	393	390							364	20	384				
1965	417	50	467	475	427	33	460				-	-	431[b]				475
1966	477	81	558	555	500	50	550	514	37	551				412	161	28	545
1967	536	108	644	640	575	79	654	598	67	665				439	208	28	619
1968	596	146	742	728	653	112	765	687	104	791				494	248	34	708
1969					749	151	900	780	153	933				544	288	43	789
1970								875	188	1063				623	342	55	910

a/ Gross peak loads.

b/ This is the actual recorded peak in December 1965 at a time when there was load shedding which has been estimated by Harza at 63 (basic 36 and tubewell 27) and in the 1966 Power Market Survey at 40 (basic 10 and tubewell 30).

c/ Stone & Webster Northern Grid load forecast grossed up 4 percent in 1966 and 1967 (when the system is heavily thermal) and 3.5 percent in following years (when Mangla will be meeting an important share of the load). Stone & Webster's division of the load between "basic" and "tubewell" differs from WAPDA's in that Stone & Webster includes private wells and all types of public well under the tubewell load, whereas the PMS public tubewell classification includes only the SCARP wells (WAPDA's Salinity Control and Reclamation Projects). The Stone & Webster Pumping figures presented here are as originally projected by them; they have not been revised to take account of the final revision in pumping loads by IACA.

Table 44

Comparative Load Forecasts, a/ Upper Sind Grid System
(mw)

	Harza, June 1963	PMS, July 1964	PMS, July 1965			PMS, July 1966			ACTUAL	Stone & Webster		
				Public			Public				Public	
	Total	Total	Basic	Tubewells	Total	Basic	Tubewells	Total		Basic	Tubewells	Total
1961												
1962												
1963	10.9 b/								2.6			
1964	13.9 b/	4.5							3.9			
1965	15.7	18.0	9.0	-	9.0				5.3			
1966	17.4	29.0	15.7	5.7	21.4	12.3	-	12.3		10	14 c/	24
1967	19.2	38.9	18.8	14.4	33.2	19.2	17.2	36.4		14	25	39
1968		49.4	21.9	23.1	45.0	23.7	22.2	45.9		18	33	51
1969			25.0	31.9	56.9	28.2	40.6	68.8		23	47	70
1970						32.8	61.9	94.7		37	67	104

a/ Gross Peak Loads.
b/ Including isolated WAPDA and non-WAPDA loads, expected to be subsequently connected to the grid system.
c/ Interruption omitted for the sake of comparability with the WAPDA figures; these figures have not been revised to take account of IACA's final adjustments to the pumping load.

Table 45

Comparative Load Forecasts,[a] WAPDA Lower Sind Grid System
(mw)

	Harza, June 1963	PMS, July 1964	PMS, July 1965			PMS, July 1966			ACTUAL	Stone & Webster		
				Public			Public				Public	
	Total	Total	Basic	Tubewells	Total	Basic	Tubewells	Total		Basic	Tubewells	Total
1962	17.2 [b]								17.2			
1963	19.7 [b]								17.4			
1964	22.1	32.7							24.7			
1965	25.1	47.9	35.0		35.0				27.8			
1966	28.2	61.0	46.6	0.7	47.3	38.3		38.3		38	-	38
1967	31.2	73.5	59.0	1.0	60.0	48.8	2.0	50.8		45	-	45
1968		87.2	74.0	1.3	75.3	66.0	2.0	68.0		53	-	53
1969			93.1	1.7	94.8	83.2	2.4	85.6		63	2	65
1970						100.4	2.4	102.8		73	3	76

a/ Gross Peak Loads.
b/ Including loads on WAPDA isolated power stations, later attached to the local grid.

Table 46

Karachi Electric Supply Corporation Ltd.
Forecasts of Maximum Demand
1966-75
(mw)

Year	Laramore, Douglass & Popham for KESC			Stone & Webster for the Bank	KESC	
	Without Petro-chemical Industry	With Petro-chemical Industry		With Petro-chemical Industry	With Petro-chemical Industry	
	(gross)	(gross)	(estimated net)	(net)	(gross)	(estimated net)
1965	149	149	141	133	129*	121
1966	182	195	183	156	153	144
1967	216	241		180	186	
1968	253	291	274	218	210	198
1969	291	342		258	244	
1970	333	395	371	309	292	275
1971	376	455		358	342	
1972	423	516	485	418	397	373
1973	471	580		487	457	
1974	526	650		560	522	
1975	585	724	661	642	600	564

* Actual Maximum Demand.

NOTE:

1. Laramore, Douglass & Popham's estimates were made early in 1965 before the September war with India and are gross station demands.
2. Stone & Webster's estimates were made at the end of 1965 before the full effect of the war could be assessed and are net of station use.

not included in Stone & Webster's forecast. Other major differences are: an increase of 15 mw in WAPDA's allowance for the Wah Ordnance Factory (a load which Stone & Webster holds constant), and a saving of about 10 mw which Stone & Webster considers attainable by reduction of losses (an item which WAPDA projects at an unchanged percentage of total load). The remaining difference of about 40-50 mw is attributable tc general industrial load. Between 1960 and 1964 WAPDA's industrial sales in the Northern Grid area are estimated to have grown at about 13 percent per annum and the rate of growth implicit in the new WAPDA load forecast appears to be higher. There is no evidence of unanticipated power-intensive industries being established in the Northern Grid area in the near future, and the PMS may have somewhat exaggerated the speed with which santioned industrial projects will be undertaken. However WAPDA should have more up-to-date information regarding the immediate future than Stone & Webster had.

4.71 It is much harder to assess the load forecasts for the Sind because loads there have been so insignificant in the past and because the Sind has suffered so severely from shortage of capacity. Moreover Stone & Webster's load forecast as distinct from the others does not break down the pumping load between Upper and Lower Sind; this has been done for the purposes of Tables 44 and 45 on the basis of the schedule of projects which was behind IACA's pumping load forecast. As in the North, the main divergence appears to be in the basic load, and specifically in the industrial portion of it. Stone & Webster have a slightly higher forecast than WAPDA of basic load in the Upper Sind, presumably as a result of their assumption that the Esso fertilizer plant would be supplied by WAPDA by 1970, which now seems less likely because Esso plans to install generating equipment initially. Exclusion of this load would put the Stone & Webster load forecast for Upper Sind about 10 mw below that of the PMS. For the industrially more significant Lower Sind (Hyderabad area), Stone & Webster projects a rate of industrial load growth of 20 percent per annum between 1965 and 1970. Yet their forecast of basic load is still more than 25 percent below the PMS forecast of basic load in the area. The PMS has evidently foreseen intensive industrial growth at Kotri as well as Hyderabad. Here again projections may have been unduly influenced by santioned industries which may not materialize as quickly as forecast.

4.72 Although WAPDA is responsible for the planning of power development throughout West Pakistan, responsibility for load forecasting in the Karachi area has remained entirely with KESC. Table 46 presents a number of load forecasts that have been made for Karachi. The forecast by KESC itself is the most recent, having been made in June 1966 -- it is intended to be a conservative forecast, having been made largely for financial purposes. It includes an allowance of 17 mw in 1970 for the load of a projected petrochemical complex. Further development has now taken place on this matter and KESC foresees by 1970 a possible petrochemical peak demand as much as 63 mw. This would make KESC's gross load equivalent to about 355 mw by 1970, corresponding to about 325 mw net load, or about 15 mw more than Stone & Webster projected. However there is still some doubt as to whether the full 63 mw of petrochemical load will be achieved by 1970; many of the projects are still in the planning stage or awaiting financing. Therefore the Stone & Webster figure, which in effect assumes that about 40-50 mw of the petrochemical load will actually be achieved by 1970, seems reasonable for planning purposes.

4.73 A major prospective load in Karachi about which uncertainty continues is the proposed steel mill. The latest report by the National Steel Corporation of Pittsburgh recommends an arc-furnace mill to produce about 500,000 tons of finished products each year from local and imported scrap. A 120 mw power plant to serve the needs of the mill has been included in the scheme. There is uncertainty whether the load, with its large voltage fluctuations, could be met by KESC by the early 1970's. The source of power, as well as the completion date for the mill, still remain open questions. Stone & Webster assume that the mill will be established with its own generating plant early in the 1970's, but that from 1973 it will be taking increasing quantities of energy from KESC. The steel mill, as well as the petrochemical complex, would serve to raise KESC loads by 1975 from the level forecast by KESC to the level forecast by Stone & Webster.

4.74 In summary, this comparison between the power consultant's load forecast and the short-term load forecasts made by others shows that, despite the numerous differences in methodology and in composition of the prospective loads, the significant differences regarding the near future are confined to the basic load, and the only difference of real importance seems to be on the peak to be expected on the Northern Grid system. It is true that the difference between the forecasts of peaks on the Lower Sind Grid system is a larger proportion of the likely peak there (about 25-30 percent in 1970) but it is much smaller in absolute terms. Moreover, it is much more unpredictable because of the very small base from which economic development will be taking place there, and is to some extent compensated by a difference in the other direction in the forecasts of Upper Sind peak loads. On the other hand the difference between the expected peaks on the Northern Grid system is about 100 mw in 1970.

Conclusion

4.75 In the selection of a load forecast for purposes of long-term planning the role which the load forecast will play in the planning exercise has to be kept in mind. The main questions at issue in the development of West Pakistan's electric power system concern the selection of hydroelectric projects, the scheduling of installations of the units in the hydroelectric plants, EHV transmission and the type, extent and location of thermal capacity that should be introduced over the next 10-20 years to firm up the hydroelectric plants. A load forecast appropriate for studying these questions will not be the same as a load forecast appropriate, for example, for financial projections. It should rather err on the generous side in order to make sure that plans are made sufficiently far in advance to cope with the loads when they come. On the other hand, it is important that this should not lead to exaggeration of likely future loads. Firm hydroelectric capacity will be relatively expensive and, other things being equal, the longer the units can be deferred the better. The type of thermal units which are appropriate for installation over the next ten years depends quite intimately on the extent to which they will be used after Tarbela comes into operation. Peaking units or extended rating turbines, which are relatively cheap in capital cost, will be more

appropriate if they are used relatively little between 1975 and 1985; whereas regular steam units, with their higher capital costs, will be more appropriate if they are likely to carry substantial load at that time because of their operating economies. So it is important that the order of magnitude of the load forecast be correct. It is also important that the load forecast give a fair indication of the likely regional distribution of load growth (especially as between the North and South) because the merits of different transmission systems depend closely on this.

4.76 The Bank Group believes that the Stone & Webster forecast of basic load generally meets these criteria. The order of magnitude is reasonable. The growth of residential consumption may be a little less than projected by the power consultant especially in the earlier part of the period but it is preferable, as pointed out above, for long-term planning purposes to err on the generous side. The growth in industrial load may be slightly less than projected by Stone & Webster in the Fourth and Fifth Plan periods (see para. 4.34). On the other hand Stone & Webster's forecasts of both industrial load and overall basic load imply that growth will tail off quite severely in the Sixth Plan period (1980-85), as indicated by the following summary of their load forecast, Table 47. Annual rate of growth in the power load does, of course, tend to taper off as systems mature although the annual increments in load may be as great as, or even larger in absolute terms, than those attained in earlier years. But West Pakistan will not have the "mature economy" typical of the more industrial countries by 1985 and continuing rapid growth of industrial output and of family incomes will likely tend to sustain a rate of growth in systemwide basic load of at least 9-10 percent per year. Therefore, while the growth rate attributed to the industrial load in the Stone & Webster forecast may be a little too high in the middle of the Perspective Plan period, it may also be a little too low at the end of the period. On balance the Stone & Webster load forecast, adjusted for the revised pumping load, appears appropriate for planning a long-term power program. The forecasts should, of course, be reviewed every year and adjusted for significant changes in future requirements, as and when recognized.

4.77 The Bank Group also firmly believes that Stone & Webster's prediction as to the regional distribution of the load is also reasonable for planning purposes. Stone & Webster predicted that power requirements will grow more rapidly in the South (Karachi and the Sind) than in the North. The Bank Group's studies suggested that there is somewhat greater potential for rapid increase of the residential load in Karachi than elsewhere, but the main matter affecting the regional pattern of overall load is the distribution of industry. This is discussed more fully in paras. 4.68-4.74 above. Karachi, the largest city in the Province, has the advantage of a relatively well developed industrial infrastructure and the Sind has the advantage of its extensive natural gas resources. In the North, industrial development will probably be mainly concentrated in consumer goods industries and agricultural processing factories which are not major consumers of power. The trend in Karachi on the other hand is toward generally power intensive industry.

TABLE 47

ENERGY FORECASTS: STONE & WEBSTER'S BASIC LOAD AND IRRIGATION AND AGRICULTURE CONSULTANTS' REVISED PUMPING LOAD a/

(Million of kwh net)

	1965 b/		1970		1975		1980		1985	Average Annual Rate of Growth 1965-85(%)
Northern Grid										
Industrial c/	820	(11.4)	1410	(10.0)	2270	(8.9)	3480	(7.6)	5030	9.5
Residential-Urban d/	207	(11.9)	364	(11.1)	616	(10.4)	1012	(9.6)	1600	10.7
Rural	36	(22.0)	98	(17.2)	217	(11.3)	370	(9.4)	580	14.9
Comm. & Pub. Lighting	77		165		297		507		822	12.6
Bulk	130		220		335		455		550	
Dam Sites	138		220		30		-		-	
WAPDA Use & Losses	412		615		835		1218		1688	
Agricultural Pumping e/	680	(17.8)	1514	(11.6)	2628	(6.2)	3547	(6.2)	4793	10.3
TOTAL	2480	(13.2)	4606	(9.4)	7228	(7.9)	10589	(7.3)	15063	9.5
Upper Sind										
Industrial	10	(70.0)	145 f/	(8.7)	220	(6.4)	300	(6.4)	409	20.0
Residential-Urban	4.8	(16.7)	10.4	(16.0)	21	(14.3)	41	(11.0)	69	14.2
Rural	1.3	(29.0)	4.6	(23.0)	13	(17.4)	29	(12.8)	53	20.3
Comm. & Pub. Lighting	3		10		24		58		81	
Bulk	1		4		5		6		8	
WAPDA Use & Losses	7		41		67		97		145	
TOTAL	27	(52)	215	(10.2)	350	(8.3)	521	(7.8)	765	19.6
Lower Sind										
Industrial	83	(19.9)	204	(15.5)	420	(12.8)	720	(9.4)	1130	14.0
Residential-Urban	14.7	(16.1)	31	(13.3)	58	(12.6)	105	(10.5)	173	13.1
Rural	1.3	(25.0)	4	(17.5)	9	(19.5)	22	(14.3)	43	19.1
Comm. & Pub. Lighting	11		24		48		86		154	
Bulk	4		6		9		14		20	
WAPDA Use & Losses	38		80		146		233		350	
TOTAL	152	(18.1)	349	(14.6)	690	(11.4)	1180	(9.6)	1870	13.4
SIND PUMPING g/	4		56	(47.5)	388	(11.9)	680	(11.9)	1192	33.0
TOTAL SIND	183	(28.0)	620	(18.2)	1428	(10.8)	2381	(10.0)	3827	16.5
Karachi										
Residential	111	(12.9)	204	(12.6)	370	(12.1)	655	(11.3)	1120	12.2
Commercial	68		149		294		535		900	
Industrial h/	355	(22.0)	980	(17.9)	2230	(11.6)	3870	(8.5)	5830	15.0
Street Lighting	5		7		10		14		20	
Misc. & Bulk	89		150		242		362		515	
Agriculture	6		11		14		19		25	
Losses	76		174		360		600		890	
TOTAL	710	(18.7)	1675	(16.1)	3520	(11.5)	6055	(8.9)	9300	13.8
Quetta Total	16		43		85		134		210	
Total Utility	3389	(15.4)	6944	(12.0)	12261	(9.4)	19159	(8.2)	28400	11.2
Industrial Generation	544		650		915		1000		1103	3.6
Total Generation	3933	(14.1)	7594	(11.6)	13176	(8.9)	20159	(7.9)	29503	10.6

a/ Figures in brackets represent annual growth-rates over the relevant periods in percentages.
b/ Base, as estimated by Stone & Webster, represents a consolidation of all utilities on the assumption that their service areas will shortly be supplied entirely from WAPDA sources.
c/ Excludes consumption at dam sites but includes an annual item of 30 million kwh which the power consultant estimated as the past and future supply of the Wah Ordnance Factory.
d/ "Urban" is defined by the power consultant as including those places which were cited by the 1961 census as having a population in excess of 25,000 in 1961.
e/ Public and private tubewells including pumping load losses.
f/ Estimate assumes WAPDA would serve Esso fertilizer plant in 1970 with 100 million kwh at maximum load of 15 mw; subsequent development of this industrial load also assumes substantial expansion of fertilizer, cement, textiles and food processing industries.
g/ Including losses.
h/ Including sales to proposed petrochemical complex.

4.78 Expressing its belief that the power consultant's load forecasts are appropriate for planning, the Bank Group stresses that this is based on its judgment of what now seems likely. Obviously things can change rapidly in a country that is developing as dynamically as Pakistan has in recent years. For this reason it is all the more important to keep the load forecasts under constant surveillance. WAPDA does make its short-term forecasts, but the Bank Group believes that WAPDA's load forecasting could be strengthned (see suggestions in Annex 1). More attention should be devoted to the long-term perspective. Stone & Webster have developed some useful concepts for this purpose and recommended that there should be more coordination between economic planning and load forecasting. Load forecasts, like the Perspective Plan, should be frequently revised and updated in the light of recent information and new prospects.

4.79 Continuous review and revision of load forecasts helps to cope with the very great uncertainties which inevitably surround predictions made 20 years into the future. Another procedure which helps to deal with uncertainty and which the Bank Group recommends WAPDA to adopt is the use of alternative load forecasts; studies can be made, for instance, to see whether or not a recommended addition to the power system is appropriate for both a higher and a lower load forecast. This can help considerably to clarify the task of the decision-maker.

4.80 Chiefly because it believes that use of alternative load forecasts is a helpful procedure, the Bank has made an alternative load forecast for the area in which there seems to be the greatest uncertainties and it has used this for certain of its studies. It was pointed out above that the most significant divergence between the load forecasts prepared by the Pakistan Authorities and those prepared by Stone & Webster arises over the basic load in the Northern Grid zone. The Bank Group strongly believes that Stone & Webster have made a sound judgment on this matter. Nevertheless there are some major uncertain factors regarding prospective loads in the North. Some were referred to above, e.g. the size of the Tarbela construction power load. There are others which may affect the loads at later dates. Several technical consultants have investigated the iron ores at Kalabagh, and some believe that, with the aid of a new process, the iron could be economically recovered in a plant producing 500,000 tons of finished products and consuming about 260 million kwh per annum. Another industrial possibility that is being investigated and that could be important from the power point of view is the production of sulphuric acid from gypsum deposits in the North for use in the manufacture of phosphatic fertilizer.

4.81 The forecast adopted for handling these uncertainties is based on a trend prepared by Harza, WAPDA's consultant, and provided to the Bank Group during discussions in Pakistan in November 1966. This forecast represents a rough extrapolation of the trend implied by the Power Market Survey Organization for the Third Plan period. It makes ample allowance for the uncertain factors discussed above and it ends with a basic load in 1985 some 50 percent higher than that used by the power consultant. The following table shows the two forecasts of basic load for the Northern Grid area. It will be noted that both forecasts adopt the same base-year data.

Table 48

Northern Grid: Alternative Forecasts of Basic Load (Net) a/

	Stone & Webster		Harza	
	Energy (mln kwh)	Peak (mw)	Energy (mln kwh)	Peak (mw)
1965	1,820 (11.2%)	375 (Dec)	1,820 (13.8%)	375 (Dec)
1970	3,100 (8.2%) b/	602 (Oct)	3,480 (11.1%)	705 (Sept)
1975	4,600 (8.9%)	881 (Oct)	5,900 (10.2%)	1,150 (Sept)
1980	7,040 (7.8%)	1,440 (Sept)	9,596 (10.0%)	1,940 (Sept)
1985	10,270	2,080	15,453	3,130 (Sept)

a/ Figures in brackets are rates of growth in percent. Harza's forecast of basic load in the North has been used for the purpose of some comparative calculation in the Bank's studies in conjunction with the Stone & Webster's projections of basic loads for other areas and the revised pumping load forecast prepared by the irrigation & agriculture consultant (see Table 47 for summary). The Bank Group used the load factors implicit in Stone & Webster's projections for converting the 'Harza' energy forecast into peak loads.

b/ Sharp decline in rate of growth in this period partly due to the fact that Stone & Webster have peak requirements for Tarbela construction in 1970 and they do not include any allowance for further major construction work after Tarbela.

4.82 In its studies the Bank Group has made greatest use of the Stone & Webster load forecasts. This is mainly because, for many specific reasons cited in the above paragraphs, it believes that Stone & Webster's forecasts are sound. However some of the major questions affecting power system development have been examined from the point of view of both load forecasts. Some reference is made in Chapter VI to the implications that the higher load forecast would have for the development of the power system, as an indication of the kind of contingency planning for which the Bank Group believes an alternative load forecast is helpful.

V. THE POWER SUPPLY PROGRAM 1966-1985

5.01 To meet the requirements of the load growth set forth in Chapter IV, Stone & Webster developed a program to supply power throughout West Pakistan, using essentially three main building blocks: the expansion of the hydro potential in the North, the commitment of the whole of the reserves at the Mari gas field in the Sind to 1500 mw of locally sited generating facilities and the continuation of substantial thermal development based on Sui gas in the Karachi area.

5.02 The program proposed by Stone & Webster envisages the installation of the following new electric generating facilities over the period 1966-1985:

Table 49

Proposed Generating Facilities
(mw)

	Northern Grid		Sind	Karachi	
	Hydro	Thermal	Thermal	Thermal	Total
1966-1970	277	176	75	226	754
1971-1975	359	0	516	125	1,000
1976-1980	436	0	300	525	1,261
1981-1985	400	0	630	680	1,710
Total	1,472	176	1,521	1,556	4,725

5.03 The details and the timing of the various installations are shown in Table 50. The capabilities of the hydro units included are on the basis of minimum critical flow periods at Mangla, Tarbela and Warsak in the years indicated.

5.04 With the addition of 4,725 mw in the North, the Sind and Karachi and 32 mw at Quetta in the period 1966-85 to the existing capacity in the Province in 1965, less the 51 mw to be retired by 1985, West Pakistan would, according to the Stone & Webster program, have a power system with a capability of 5,557 mw in 1985 (at the time of the minimum hydro capability in May). That system would include the units and stations shown in Table 51.

Summary of Stone & Webster Power Generating Equipment and Transmission Line Installation
1966-85
(mw)

	Generating Equipment*/						
	Northern Grid		Upper Sind		Lower Sind & Karachi		EHV Transmission Lines
1965	Existing	431	Existing	25	Existing	275	
66	Lahore-Gas Turbines	26	Sukkur-Steam	25	Hyderabad	23	
67	Lahore-Gas Turbines	26		-	-	-	
	Lyallpur-Steam a/	124				-	
68	Mangla 1, 2 b/	131		-	Lower Sind-Gas Turb.	26	
					Hyderabad-Retire	(3)	
69	Mangla 3 c/	66	Mari-Gas Turbines	26	Lower Sind-Gas Turb.	52	
1970	Warsak 5, 6	80	Mari-Gas Turbines	24	Korangi 3 f/	125	
71	Mangla 4	65	Mari-Gas Turbines	96	Karachi-Nuclear #1	25	Mari to Karachi g/
72	Mangla 5, 6	132		-	Karachi-Nuclear #1	100	
	Retire	(16)					
73	-	-	Mari-Steam-1	120	Karachi-Retire	(15)	Mari to Lyallpur g/
74	-	-	Mari-Steam-2	150	-	-	Mari to Karachi Tarbela to Lyallpur
1975	Tarbela 1, 2 d/	162	Mari-Steam-3	150	-	-	
76	Tarbela 3, 4	162	-	-	-	-	
77	Tarbela 5, 6	149	-	-	Korangi 4	125	Tarbela to Lyallpur Lyallpur to Mari
78	Tarbela 7, 8	125	-	-	Korangi 5	200	
79	-	-	Mari-Steam-4	150	-	-	
1980	-	-	Mari-Steam-5	150	Korangi 6	200	
81	Mangla 7, 8	139	Mari-Steam-6	150	-	-	
82	Tarbela 9, 10	125	-	-	Karachi X	200	Tarbela-Lyallpur
83	Tarbela 11, 12 e/	136	-	-	Karachi Y	240	Lyallpur-Mari
84	-	-	Mari-Steam-7	240	Karachi Z	240	
1985	-	-	Mari-Steam-8	240	-	-	
Total Capabilities		2,063		1,546		1,813	

a/ Units expected in service by February 1967 and July 1967.
b/ Units expected in service by June 1967
c/ Units expected in service by third quarter of 1968.
d/ Units expected in service by fourth quarter of 1974.
e/ Difference between 1985 and 1980 water releases adds 11 mw capability to Mangla units.
f/ Units expected in service March 1969
g/ Operated at 220 kv until 1974.

*/ Retired equipment capacity in brackets. Units assumed to be in commercial operation by January 1 of year designated except as noted.

Table 51

Amounts of Hydro and Thermal Capacity in System as of 1985

	Megawatts
Hydro units in the North (May)	1,717
Gas turbines at Lahore, Multan, Mari and Hyderabad	288
Diesel units at Lyallpur and Karachi	27
Steam stations at Multan, Lyallpur, Sukkur and Hyderabad using Sui gas	459
Steam stations at Karachi using Sui gas	1,547
Nuclear station at Karachi	125
Steam stations at Mari	1,350
Steam stations at Quetta using coal	44
Total	5,557

5.05 The development of this program was influenced, for the short term, by additions to the system already authorized or expected, and for the long term, by certain basic assumptions and thinking about the future shape of the power system of West Pakistan.

Additions Expected During 1966-70

5.06 It may be seen from Table 49 that Stone & Webster proposed the addition, in the period 1966 to 1970, of 477 mw of thermal capacity. Of this part of the program 323 mw were already authorized. The authorized additions were: in the Northern Grid, 26 mw of gas turbines being installed at Lahore and two steam turbine generators of 62 mw net each expected to be in operation by mid-1967 in Lyallpur; at Sukkur, two 12.5-mw steam turbine units which were scheduled to be in service by 1967 to supplement the first two units of the same size at that station to bring the capability of this area up to 50 mw; at Hyderabad two steam turbine units having a combined capability of 23 mw were expected in service during 1966 to bring the capability of this area to 43 mw; at Karachi, a 125-mw steam turbine was planned for operation in March 1969. In addition, a 125-mw net nuclear power generating unit was approved which was scheduled to commence operations during 1970.

5.07 Stone & Webster also proposed for the period 1966-70 the addition of some 380 mw of hydro capability. Of this, three 100-mw nominally rated hydro units at Mangla were scheduled for operation, two in the second quarter of 1967 and the third in the third quarter of 1968 plus two additional units at Warsak giving 80 mw more of capacity.

5.08 Since Stone & Webster submitted their report, WAPDA has announced that orders have been placed for 39.0 mw of gas turbines to be installed in the Hyderabad area in 1967; for an additional

26 mw of gas turbines to be installed in Lahore early in 1968; for 200 mw of steam capacity to be installed near the Mari gas field for operation about 1969, and for another steam unit at Mari perhaps in 1970/71. On the hydro side, WAPDA has announced that orders have been placed for a fourth generating unit at Mangla for operation in 1969 and that units 5 and 6 would be installed at Warsak without a re-regulating dam downstream as soon as practicable. These units were scheduled, in the power consultant's program (as noted above), to be installed in 1970, but with the addition of the costly re-regulating dam.

5.09 The schedule of these installations varies considerably from the timing envisaged by Stone & Webster and consequently will affect the timing and direction of the interconnection proposed between the different regions which, as described in Chapter II, are at present isolated from each other electrically. It may also affect the initial voltages of the transmission lines. These changes do not necessarily affect the basic thinking and assumptions which underlie Stone & Webster's long-term program as will be discussed in the following pages.

Basic Thinking Underlying Stone & Webster Program

Interconnection

5.10 The Stone & Webster program is based on the premise that the different regions of West Pakistan will be progressively interconnected. West Pakistan's electrical load is concentrated in the Northern Grid which, in 1965, had a peak load of over 400 mw and in Karachi which had a load of about 120 mw. These two load centers are separated by 575 air miles. Hydroelectric power plants having an annual output of 20 billion kwh a year are planned for installation along the northern rim of the Northern area. What was considered, at the time Stone & Webster were working, to be a large reserve of inexpensive low-quality gas adequate to supply electric generating capacity is located almost exactly between the two major load centers. Bulk transmission lines could connect the sources of generation to the load areas (see Map 2 at the end of Chapter VII). Such ties could, according to Stone & Webster, have several benefits among which would be the ability to:

1) Provide an outlet for much of the excess hydro energy at times of high discharge in the rivers. (The distance from Tarbela to Karachi is about 845 miles.)

2) Make available to the Lower Sind and Karachi and also to the North, during periods of low hydro capability, electricity generated from low-cost Mari gas at the gas field.

3) Share generating capacity reserves between areas permitting an overall reduction in reserves and some possible increase in size of units, particularly in the Hyderabad and Sukkur areas.

5.11 Stone & Webster therefore worked with the following schedule of interconnection:

Lower Sind (Hyderabad)to Karachi	1967 (132 kv)
Upper Sind (Mari) to Karachi	1971 (380 kv)
North to Upper Sind (Mari)	1973 (380 kv)
Upper Sind to Quetta	1981 (220 kv)

Since the interconnection between Hyderabad and Karachi will be carried out in the near future, the two areas are treated as one in the Stone & Webster evaluation. On the other hand, until 1973, at which time the interconnection between the North and Karachi is proposed, the requirements for Karachi/Hyderabad, Upper Sind and the North and the reserves for each area are treated separately. After the North-South interconnection has been made, reserves of about 9 to 12 percent are envisaged in May under mean-year conditions, and somewhat less (but always at least six to seven percent) under critical water-year conditions. Quetta is treated separately throughout.

5.12 Stone & Webster believed that the bulk transmission needs of the Province could be met more advantageously through the use of high voltage alternating current transmission rather than by high voltage direct current transmission. Their studies of 500-kv and 380-kv high voltage transmission lines led them to the conclusion that economics and other factors favor the use of 380-kv lines.

Future Hydropower Possibilities

5.13 Stone & Webster expect that the principal and most likely possibilities for the further development of hydroelectric power in West Pakistan in the next 20 years will be at Mangla and Tarbela Dams and the addition of two more 40-mw units at Warsak. Hydro projects on the Kunhar River, a tributary of the Jhelum, and on the Gomal River, a tributary of the Indus, were evaluated but have been rejected as being too costly for inclusion at this time in the program. The Kunhar Project, which would have a firm capability of about 500 mw was not considered by Stone & Webster to be justifiable in the near future as long as Mari gas is available to provide a cheaper source of energy. In their opinion Kunhar might be utilized later depending upon the price of fuel whereas the Gomal project appeared to them to be doubtful value for power inasmuch as the reservoir would be filled only once in about every 10 years and the energy available would be relatively small.

Hydropower Capabilities

5.14 Stone & Webster's hydropower program is thus centered upon Mangla and Tarbela. Because hydro units at both these dams (and to some extent at Warsak) have varying capabilities depending on the amount of water passing through the turbines and the height of the water in the reservoirs, the power consultant had to establish certain parameters for estimating the hydro capacity at each dam. Stone & Webster's procedures are presented below.

5.15 The Mangla and Tarbela Reservoirs would be filled during the heavy flow season of the Jhelum and Indus Rivers from May or June through August. Starting in September or October, water would be released from live storage to supplement the natural river flow to supply the needs of agriculture. The amounts of water to be released each month would be scheduled so that the reservoirs would be nearly or entirely emptied of live storage by the time the river flows increase substantially in May or June. River flows and agricultural water demands are such that the filling of Mangla Reservoir would have to start early in May whereas the filling of Tarbela Reservoir would probably not begin until early in June.

5.16 The amount of water supplied to agriculture would be available to generate electric power or, if greater than needed for power generation, the excess would be released through irrigation tunnels or bypassed around the hydro units installed. In the late summer, after the reservoirs filled, water would have to flow over the spillways.

5.17 For calculations of available electric energy from hydro units at Mangla and at Tarbela, the average river flows for 10-day periods for 41 years (i.e. a "mean year") have been used.

5.18 For calculations of the peak loads that could be borne by the hydro units at the two reservoirs, a so-called "critical water year" was chosen. The water year of 1954/55 was selected as having the lowest combined flow figures from the Chenab, the Jhelum and the Indus Rivers during the period from the first of October through the end of May. The "critical water year" was also used to determine the addition to pumping loads that would occur under conditions of low river flow.

5.19 The amount of energy available from the hydroelectric plants will vary with the river flows and depending on the release patterns adopted for operation of the reservoirs. Release patterns used in the Study envisage Mangla Reservoir being fully drawn down by the beginning or the end of April. The reservoir would begin to fill again in the first part of May. The lowest reservoir level at Tarbela, on the other hand, would probably occur later, in late May and early June. River flows at Mangla during the October through May periods for 41 years have varied

from 6.97 MAF to 15.48 MAF. At Tarbela the river flows for the same periods have varied from 10.96 MAF to 20.25 MAF.

5.20 In a critical water-year the energy available from Mangla would be 15 percent less than in a mean year, but at Tarbela the reduction would approximate only 5 percent.

Mangla Basic Data

5.21 Mangla as it is being presently constructed will have a live storage of 4.9 MAF[1/] when the reservoir level is drawn down to a level of 1040 feet. It will, according to the dam sites consultants, decrease because of siltation to 4.56 MAF in 1985. The analysis made by Stone & Webster to determine the power capability and energy available for its basic program, assumed that the reservoir would be drawn down each spring to an elevation of 1075 feet.

5.22 The amount of drawdown and the water released from the reservoir both affect the power that may be generated by the hydro units. Calculations were made by IACA on a computer to determine the amount of peaking power and energy that might be expected from water releases and reservoir elevations for each 10-day period throughout the year. The peak power was calculated by using 20 percent greater flow than the 10-day average. The minimum power output from the Mangla units will occur during April, May and June. The nominal capacity of each unit is 100 mw; the maximum and minimum capacity depends on the head and flows available; at elevation 1040 feet, the minimum capacity would be 47 mw whereas at 1075 feet it would be 65 mw. With the reservoir full the capacity of each of the units would be 129 mw, but for short periods they could be operated at a somewhat higher level of output.

5.23 Several computer studies were also made to determine a schedule of water releases to meet the needs of agriculture. These water releases were used to determine the power capability of Mangla at different periods.

5.24 The minimum peak capability of Mangla at a drawdown level of 1075 feet in a critical water-year during several 10-day periods in the months of April, May and June as calculated by Stone & Webster, is given below. For contrast, the capability in August is also indicated.

1/ Excluding Jari Arm. Refer Volume III.

Table 52

Mangla Power Capability at Various Times of the Year
(Megawatts)

	1970	1973	1985
	4 Units	6 Units	8 Units
April 21-30	281	423	575
May 1-10a/	262	391	504
June 1-10	351	529	673
August 21-30	517	775	1,033

a/ With the minimum drawdown level of 1075 feet.

The differences in the firm capabilities with drawdowns to 1075 feet and 1040 feet based on the flow in a critical water year and the annual generation based on mean water year are shown in the table below assuming six units installed in 1975 and eight units installed in 1985.

Table 53

Mangla Capabilities at Drawdown Levels of 1075 and 1040

	Drawdown	Firm Capability (mw)		Annual Generation (Million kwh)	
	(feet)	6 Units	8 Units	6 Units	8 Units
	1075	391	504	4,950	5,760
	1040	283	381	4,780	5,433
Difference	35	118	123	170	337

Tarbela Basic Data

5.25 The Tarbela Dam, as it is presently being designed, will have a gross storage of 11.1 MAF and an initial live storage of 8.6 MAF at reservoir elevation of 1332 feet. The minimum designed drawdown level is 1300 feet. At this level the live storage would be initially 9.3 MAF. The reservoir has been projected by Chas. T. Main to silt up rapidly and in approximately 50 years the power units would then have a maximum head continuously and would operate on the run of the river.

5.26 Although the dam is being designed to permit a drawdown to a level of 1300 feet, a minimum elevation of 1332 feet was used

by the power consultant for his base power supply program. This would leave 0.7 MAF or about 7.5 percent of the live storage in the reservoir at all times.

5.27 The hydroelectric generators proposed to be installed are rated at 175 mw. The capability of the units would however, vary from 61 mw at a reservoir level of 1332 feet to 200 mw with a full reservoir. The minimum peak power capability would occur during the first part of June. The generating units will have a bypass valve coupled with the units so as to maintain a uniform discharge for agriculture. The valves will be designed to be operated manually in the event releases are required when the generating units are not in operation.

5.28 As in the case of Mangla, flows during the critical water year were used to determine the power capability, and flows during the mean water year were used to determine the energy available. Computer studies were employed to determine the amount of peaking power and energy that might be expected for each 10-day period throughout the year for what Stone & Webster call their base program (1332 feet), and their irrigation-oriented program (1300 feet) and their power-oriented program (1350 feet).

5.29 The amounts of peaking power obtainable with a 30 percent peak flow during a critical water year at a drawdown level of 1332 feet for 2, 8 and 12 generating units with a base water release is given below for April, May and June; for contrast the August capability is also indicated.

Table 54

Tarbela Power Capability at Various Times of the Year
(Megawatts)

	1975	1980	1985
	2 Units	8 Units	12 Units
April 21-30	190	738	1,085
May 21-30	125	500	751
June 1-10[a]	122	486	728
August 21-30	404	1,615	2,423

a/ With a drawdown level of 1332 feet

5.30 The difference in firm capacities and annual generation with 8 and 12 units installed under reservoir conditions in 1980 and 1985 are given below for the base program (1332 feet) and the irrigation-oriented program (1300 feet).

Table 55

Tarbela Capabilities at Drawdown Levels of 1332 and 1300

	Drawdown	Firm Capability (mw)		Annual Generation (Million kwh)	
	(Feet)	8 Units	12 Units	8 Units	12 Units
	1,332	486	728	9,637	11,944
	1,300	305	487	9,330	11,694
Difference	32	181	241	307	250

5.31 A comparison of the base program and the power-oriented program (1350 feet) with 12 units installed is shown below.

Table 56

Comparison of Base and Power Oriented Programs

	Drawdown (Feet)	Firm Capability (mw in 12 Units)	Annual Generation (Million kwh)
	1,350	896	12,221
	1,332	728	11,944
Difference	18	168	277

5.32 The increase in capacity with the power-oriented program (1350 feet) over the irrigation-oriented program (1300 feet) with 12 units installed would be 409 mw and the gain in energy production would be 527 million kwh. Not all of the energy produced, however, would be usable in the high water season.

Warsak

5.33 Two additional 40-mw units are proposed by Stone & Webster for installation at Warsak in 1970, provided a re-regulating reservoir is constructed downstream to smooth fluctuations resulting from daily releases at peak periods. This would increase the capacity of Warsak from 160 to 240 mw. With the increased capacity, 180 mw could be obtained in the winter and 240 mw in the summer. The Warsak

Reservoir is capable of storing water for daily peaking but it is too small to have any effect in firming up flows on a seasonal basis.

5.34 The peak-load capabilities of the various hydro plants differ throughout the year. The combined capability of the small low-head hydro stations, Warsak with 6 units, Mangla with 8 units and Tarbela with 12 units in a critical water-year for 1985 conditions is shown in the following table for periods of low and high flow. It will be noted that in May and June, the combined peaking power is less than half of that in August.

Table 57

Total of Combined Capabilities, 1985 Conditions
(Megawatts)

	Small Hydros and Warsak	Mangla	Tarbela	Combined Totals
Apr 21-30	325	575	1,085	1,985
May 1-10	325	504	899	1,728
11-20	325	585	859	1,769
21-30	325	642	751	1,718
Jun 1-10	325	673	730	1,728
11-20	325	691	728	1,744
21-30	325	715	1,205	2,245
Aug 11-20	325	1,012	2,423	3,760
Dec 11-20	235	538	1,265	2,038

5.35 Stone & Webster investigated a number of release and filling schedules for three different periods; 1974 pre-Tarbela, 1980 (the middle period for hydro installations) and 1985 when all Mangla and Tarbela units that appear economic would have been installed, as well as different drawdowns for Mangla and Tarbela.

5.36 In the pre-Tarbela periods there would be surplus hydro energy with any of the different schedules and only a 5.5 percent difference in total energy available in the five plans studied. For the 1980 period, the base program appeared to be better than any of the alternatives. In 1985 it was found that lowering the water level in Mangla and Tarbela Reservoirs would cause a major reduction in the combined capability of the two projects, ranging from 338 to 356 mw, and would require the addition of thermal peaking capacity, whereas changing the water release pattern for the most part only relocates the time when hydro energy would be available.

Future Thermal Power Possibilities

5.37 To meet the load requirements which they had forecast, Stone & Webster evaluated the major possibilities for the

development of thermal power to supplement hydropower which would become available at Mangla and at Tarbela. Because the hydro units would have capabilities varying with the amount of water released for agriculture through the hydro units and with the height of the water in the reservoirs Stone & Webster calculated the extent that it will be necessary to supplement hydro generation with thermal generation at times when the reservoirs are drawn down to low levels. This would occur normally in April, May and the early part of June.

5.38 Stone & Webster noted that the coal mined in West Pakistan is of relatively poor quality and that it would be more costly to use than natural gas. Fuel oil would have to be imported, therefore requiring foreign exchange and this, they concluded, would also be more costly than natural gas. Accordingly they placed a great emphasis on the installation of thermal units near the Mari gas field, and also near Karachi, using Sui natural gas for fuel.

5.39 At the time of the Stone & Webster report, both the Mari and Sui gas fields were each estimated to have 5000 million Mcf of recoverable reserves. Stone & Webster noted that KESC which purchases Sui gas from Karachi Gas Company, estimated that the average delivered price of gas is about 35 cents per million Btu. As contrasted with this, Stone & Webster estimated natural gas from the Mari gas field to be worth 12 cents per million Btu at well-head. The thermal value of this gas was then thought to be about 673 Btu per cubic foot. But Stone & Webster noted that, when designing boiler turbine gas-fired plants, relatively minor cost additions are required to use the lower quality Mari instead of the higher quality Sui gas.[1/] Since higher quality gas was, they felt, more useful to industry, it could be transmitted economically and would have a higher opportunity cost.

5.40 They concluded, therefore, that it was desirable to install generating capability near the Mari gas field approximately halfway between the heavy load areas of the Northern Grid and of Karachi, burn Mari gas for power generation to supplement the hydro generation in the North, and otherwise supplement the higher cost Sui gas power generation in Karachi and Lyallpur. The electric transmission installed for transmitting this power would also be used to transmit excess hydro generation from the Northern Grid to Sind and Karachi.

Nuclear Generation

5.41 Stone & Webster pointed out that nuclear generation is economical only in relatively large units, preferably in the range of 400 mw, and where a high sustained load may be carried on each unit. A nuclear reactor vessel for a 200-mw plant or larger cannot

1/ Sui gas heating value is 975 Btu per cu. ft.

be transported by the Pakistani railways at present, but assuming that such a plant could be constructed near Mari in 1980, it would not be competitive with a gas-fired plant both because of its high initial capital cost (nuclear power units require the highest proportion of foreign currency for installation and operation) and because it could not be operated at a high plant factor (owing to the availability of hydro energy during a large part of the year).

5.42 A nuclear plant of about 400 mw or larger might become economical in Karachi about 1984, according to Stone & Webster.

Alternatives Considered by Stone & Webster to their Power Supply Program

5.43 The program outlined in Table 50 was considered by Stone & Webster to be the most economical in terms of total annual costs for fixed charges, operation, maintenance, fuel and miscellaneous charges throughout the 20-year period. This conclusion was reached by the consultant after having studied a number of alternatives.

5.44 Stone & Webster considered installing Mangla units 7 and 8 directly following units 4, 5 and 6 and concluded that this was not as economic as installing a 120-mw steam unit at or near the Mari gas field in 1973. They scheduled Mangla units 7 and 8 to be installed by 1981, when the load had grown sufficiently to absorb more of the potential hydro energy. They estimated that the low point in system capability would occur in 1973 during the first 10 days of May; at that time the two units would add only 91 mw capability to the system. Later, by 1981, after Tarbela units are installed, the low point in capability at Mangla and Tarbela combined would change to the last 10 days of May when the Mangla units would add 139 mw. The added 48 mw of minimum capability and the greater usage of the hydro energy potentialities would then appear to make the Mangla units 7 and 8 desirable.

5.45 Stone & Webster considered the installation of two additional units at Mangla utilizing the fifth tunnel but concluded that Mangla units 9 and 10 did not appear economic at any time during the planning period. These units would not add peak-load carrying capability during May and June when hydropower would be at a minimum and would not provide additional energy during six months of the year. Although the extra energy of about 240 million kwh available during April, May and June would be useful, during March, July and August other units would be available which could generate more hydro energy than could be used. Since units 9 and 10 would not add firm capability when needed and only a relatively small amount of additional energy, Stone & Webster concluded that they would not be justified.

5.46 Stone & Webster proposed that the first eight Tarbela units should be scheduled, two each year, with the first two being

completed in the fall of 1974. The first 8 units are believed to be more economical than steam units of similar capacity. After the first 8 Tarbela units they proposed the installation of three 150-mw Mari steam units to be followed by Mangla 7 and 8 before Tarbela units 9 through 12 which would be scheduled in 1983 and 1984. A study was made of the possible effect of installing Tarbela units 9 through 12 in place of the two Mari steam units they proposed for 1979-80. It was concluded that, as much of the energy from Tarbela units 9 through 12 could not be used in 1980/81 and as Mari steam units would require less transmission and have lower initial costs, the scheduling of units 9 through 12 in 1979/80 would not be preferable to the sequence proposed in their program.

5.47 The entire omission of Tarbela units 9 through 12 and replacing them with steam units was considered by Stone & Webster. By 1982 and 1983 when Tarbela units 9-12 are proposed, steam units at Mari included in their program would have committed the use of all Mari gas reserves during the expected life of those units so that the more costly Sui gas or oil appeared the proper fuel to use for making a cost comparison. The fixed charges and annual operating costs including fuel for the two 150-mw units required would be about twice the annual costs of the hydro units.

5.48 Stone & Webster also considered the economics of installing Tarbela units 13 through 16. Their studies showed that even though each unit might generate a peak load of 200 mw through August and September, the total of the four units would only add about 175 mw during May 21-30, the time of minimum hydro capability. Furthermore, these units would add no capability from the 11th of October through the 20th of April, a span of slightly over six months. Also for the six months from October through March, the units would not produce any additional energy. The construction costs were estimated to be about 40 percent more for Tarbela units 13-16 than for 9-12 and there would be additional costs for transmitting the 800 mw of power south during the flood season. Stone & Webster, therefore, concluded that Tarbela units 13-16 should be omitted.

5.49 The consultant studied possible development of the hydropower project on the Kunhar River in the 1980's (see Vol. III, Annex 6). Seven hydro units in two powerhouses were estimated to have a combined minimum capability of 491 mw in May and a maximum of 596 mw in July. Sufficient water would be available from inflow and storage to permit an annual generation of about 2,900 million kwh per year indicating an annual 56 percent capacity factor. This was evaluated as alternative generation for Mari steam units.

5.50 Stone & Webster estimated the construction cost of Kunhar at a rate of PRs 1,825 per kw as compared with PRs 1,275 per kw for Tarbela units 9-12 and PRs 960 per kw for Mari units

of about the same capability as the Kunhar development. They concluded that development of Kunhar hydro depended upon the fuel situation in West Pakistan in the 1980's. If the alternative was imported fuel oil, it appeared that Kunhar should be incorporated in the system. But they felt a further study should be made in about 10 years to determine how to schedule power generating units during the middle 1980's. The then known reserves of gas and oil would influence the conclusions of that study.

5.51 Another feature about Kunhar, which could make its construction more attractive, was that it could provide an additional 0.4 MAF of storage, if High Mangla were not constructed. This water could also generate additional power at Mangla which could be worth almost PRs 1 million annually.

5.52 As noted earlier, a minimum reservoir level of 1075 feet was used by Stone & Webster as the basis for establishing minimum power capability at Mangla for their power program. The reservoir level at Mangla can be drawn down to as low as 1040 feet which would release about 0.4 MAF additional water for irrigation. Stone & Webster found that the lower minimum operating head on eight units would reduce Mangla's effective power capability by 125 mw during May of 1985 and would generate 150 million kwh less usable energy annually. If this reduction at Mangla were supplanted by an equivalent steam installation at Mari it would cost about PRs 10.6 million annually. This amounted to about PRs 27.0 per acre-foot per year for the water retained in the lower part of Mangla's Reservoir.

5.53 Stone & Webster considered the effect on power of raising Mangla Dam by 48 feet, given different assumptions:

Case A

5.54 That all additional water stored would be released for irrigation on a schedule similar to that used in their analysis of Low Mangla. They found that Jhelum flows were insufficient in 8 of the 41 years, 1922-63, to fill the larger reservoir (drawn down to 1075 feet) after meeting May-August irrigation requirements of 3.6 MAF (somewhat higher than the kharif irrigation requirements projected by the irrigation consultant for 1985). They also found it would be necessary to install 240 mw of thermal generation to equal the hydro capability lost in May, June and July because of the reduced outflow from the larger reservoir to permit its filling. This would result in a penalty or charge against irrigation amounting to PRs 11.7 million annually to compensate for the increase in power costs which was approximately PRs 4.0 per acre-foot of extra water stored in High Mangla. All of the costs of raising the dam were assumed to be charged to irrigation.

Case B

5.55 That Mangla would be raised for power purposes alone, with release for irrigation from storage of the same amount of water as would be released from Low Mangla. Stone & Webster calculated that this would save the installation of about 300 mw of thermal capacity, at a construction cost of some PRs 300 million. Since the dam sites consultant had estimated the cost of raising the dam at PRs 730 million at prevailing prices, excluding taxes, duties and interest during construction, it was concluded that to raise Mangla Dam for increased power benefits alone was not economical.

Case C

5.56 That rather than 1075 (irrigation oriented) or 1190 (power oriented) an intermediate drawdown of 1130 feet should be adopted, allowing some additional water for irrigation and also some to be retained for increasing power capability. Stone & Webster concluded that there would be a reduction in power capability of 145 mw as compared with that available from Low Mangla. This would be somewhat less than the reduction in Case A. The table below summarizes cases A and C and compares them with their proposed program.

Table 58

Comparison of Cases A and C

		Low Mangla	High Mangla Alternatives	
			A	C
Minimum reservoir drawdown level	feet	1,075	1,075	1,130
Water released	MAF	4.17	7.72	6.75
Extra water released	MAF	0	3.55	2.58
Loss in capacity b/	mw	0	240	145
Gain in usable energy	million kwh per year	0	1,030	1,210
Annual fixed and operating costs a/	millions of rupees	0	11.66	2.58

a/ Related to Low Mangla
b/ During critical period on power system.

Case D

5.57 That the dam should be raised to an intermediate height instead of the maximum of 48 feet. Stone & Webster studied the

effects of drawing the reservoir level down to 1075 feet from levels of 1218 feet, 1235 feet and 1250 feet. In each case, they found there would be a loss of power capacity as compared with Low Mangla in their proposed program.

5.58 On balance, Stone & Webster concluded that raising the height of the Mangla Dam for power alone would not be economical.

5.59 They also considered the problem of whether the Tarbela Reservoir should be drawn down to 1300 feet instead of 1332 feet. A minimum reservoir level of 1332 feet was used as the basis for establishing minimum power capability at Tarbela for their report. This level was selected at an early date in the study as the minimum at which the turbine units would not encounter excessive vibration. But it was later believed possible with present designs to operate with a minimum reservoir level of 1300 feet. A study showed that drawing the Tarbela Reservoir down to 1300 feet for irrigation would result in the loss of 245 mw of capacity and 230 million kwh of energy. The loss of capacity would have to be made up during the critical low-flow period with thermal capacity elsewhere in the system.

5.60 Stone & Webster considered drawing Tarbela down to 1350 feet for the benefit of power. They found that there would be a gain to power of 166 mw of capacity and 231 million kwh in energy. This gain would merit consideration provided the loss of 0.6 MAF of water for irrigation would not be serious.

5.61 The following table summarizes the important physical data relating to the comparisons described in paragraphs 5.59 and 5.60. These physical values were evaluated and reduced to annual costs for comparison, using Mari steam costs as a basis.

Table 59

Different Minimum Reservoir Levels -- Tarbela
(1985 Conditions -- 12 Units)

		Base	For Power	For Irrigation
Minimum reservoir drawdown level	feet	1,332	1,350	1,300 a/
Water released --	MAF	7.3	6.9	7.9
Minimum power capacity --	mw	730	896	487
Gain or (loss) over base in useful energy -	mill.kwh	0	231	(230) b/
Annual fixed and operating costs	millions of rupees	0	14.1	(19.7) b/

a/ Assuming that power tunnel inlet levels and turbine design permit operation at this level.
b/ Negative figures in brackets.

Stone & Webster found that if annual costs for the three minimum drawdown levels are related to the change in water storage, the value to power for each acre-foot of water retained in storage is about PRs 35.0.

5.62 On balance, the power consultant concluded that his basic program set forth in Table 50 above, would be preferable to any of the various alternatives considered, at least up to about 1980. But he thought it would be advisable to keep the program under constant review.

5.63 Not all of the hydro energy that would be produced in the power consultant's base program could be used. Before Tarbela in 1974, it is estimated that 90 percent of all the hydro energy which would become available could be used. This proportion would fall to about 75 percent as the potential output of hydro energy, especially during the high-flow season, was increased by the installation of additional units at Tarbela. By 1985, however, about 83 percent of the total hydro energy that could be produced would be usable. In that year, hydro energy would be supplying 57 percent of the energy requirements of 28,530 million kwh, 26 percent would be supplied by Mari gas, 14 percent by Sui gas and 3 percent by nuclear power.

5.64 Stone & Webster's generation program includes allowances for scheduled overhauls and reserves for unscheduled shutdowns. The allowance for scheduled overhauls of hydro units is 10 days and for steam boiler turbine units, two weeks.

Basic Changes Since Stone & Webster Program was Formulated

5.65 Since Stone & Webster submitted their report information has become available which may make it necessary to reconsider some aspects of the Stone & Webster program. This information relates principally to (a) the reserves in the Mari gas field and (b) the firm capacities of Mangla and Tarbela.

5.66 Stone & Webster proposed in their base program that 566 mw of thermal capacity be installed at Mari by 1975 and 1550 mw ultimately. By 1985 it was estimated that annual use of Mari gas would be 134.5 thousand million cubic feet. This rate of offtake was expected to result in the consumption of all of the Mari reserves in about 30 years. There has, however, recently been a reduction in the reported reserves in the Mari gas field from 5.0 thousand million cubic feet to 1.8 thousand million cubic feet (including proven, probable and possible reserves). A supply of 25 million cubic feet a day has already been committed to the Esso Fertilizer factory which is under construction. Remaining proven reserves, if all committed to power, would be enough to support 400 mw at a 30 percent load factor for about 25 years, while remaining total reserves, if probable and possible are included, would be enough to support 400 mw on base load for about the same period.

5.67 Stone & Webster, as noted in paras 5.21 and 5.25, assumed 1075 and 1332 drawdown levels for Mangla and Tarbela respectively. It appears, however, to be WAPDA's intention to assume, for planning purposes, that both Mangla and Tarbela Reservoirs will be drawn down to provide water for agriculture to levels below those used by Stone & Webster in their Base Program. The implication of this for the immediate future, i.e. up to 1975, is that there would be a reduction in Mangla's planned capability in 1975 (6 units) of about 90 mw. A change in the reservoir release patterns from those used in the Stone & Webster report would further aggravate this problem if such a change meant that the releases were even more oriented to irrigation. On the other hand, a change in the release pattern to that recommended by IACA does not change Mangla's minimum capability.

Pre-1975 Implications

5.68 Stone & Webster discussed this new information and its implications for their program with the Bank Group and with the Pakistan power authorities. Their program had included 566 mw at Mari by 1975, so that the assumed limit of 400 mw on development at Mari would reduce the capability provided by their program by 166 mw. At the same time, it was necessary to take account of the addition of two gas turbines at Lahore with a combined capacity of 26 mw which had been sanctioned by WAPDA (see para 5.08) but not foreseen by Stone & Webster in their report. Table 60 summarizes these changes as they affect the generating capacity provided by the Stone & Webster program for 1975.

Table 60

Summary of Effects of Recent Changes on Stone & Webster Power Program, 1975
(megawatts)

Reduction in Mangla capability	- 90
Reduction in Mari capability	-166
Increase in Lahore capability	+ 26
	-230

In the time available Stone & Webster were not able to recast their program in full in the light of these changes. There was also doubt at the time as to whether there might not be some reductions in anticipated loads in 1975 which would at least partially compensate this reduction in capability. Stone & Webster felt that the shortfall which remained in their program after allowing for these adjustments would probably best be made up with additional gas-fired thermal equipment in the Sind or Karachi.

5.69 However Stone & Webster also thought that their basic recommendation of EHV interconnection between the North and Karachi during the Fourth Plan period would need thorough reappraisal if Mari gas reserves were indeed so much smaller than had originally been assumed. The 380-kv

transmission lines which they had planned for Mari-Karachi in 1971 and Mari-Lyallpur in 1973 might need to be delayed or abandoned; an important part of the justification for these lines, beyond their ability to carry hydro energy to the South, had been the saving in fuel costs that would be obtainable from using cheap Mari gas for supplying electricity in place of the more expensive Sui gas. If Mari could not support more than 400 mw of generating capacity it might be preferable to delay development there and to continue to rely on thermal generation, locally in the North and in the South, on the basis of the Sui gas which is carried there by pipeline. Any deficiency in the North before completion of Tarbela might therefore be met by establishment of additional thermal plant there or, alternatively, by advancing the installation of Mangla units 7 and 8.

VI. EVALUATION OF STONE & WEBSTER PROGRAM

6.01 Stone & Webster discussed in their report the complexity of preparing a long term power supply program. The basic assumptions and thinking which underlay this program were set out in Chapter IV of this Volume. An indication was also given of the changes which have taken place since Stone & Webster completed their report. This chapter describes some of the analyses made by the Bank Group of the basic elements of the Stone & Webster program. The following chapter offers an "adjusted program" which the Bank Group has prepared. This "adjusted program" within the limits of the time available to the Bank Group for this purpose, takes into account both the Bank Group's analysis of the Stone & Webster program and the changes in fundamental data.

6.02 There are four essential features to the Stone & Webster program, as shown in Chapter V: completion of the Tarbela Dam in 1975 so that its power potential could be gradually realized in the following years, heavy concentration of thermal development at Mari to provide all main load centers in the Province with thermal power produced by cheap gas there, 380-kv interconnection starting with a line between Mari and Karachi in 1971 and embracing all main load centers by the time that Tarbela came on line, and a continuation of additional thermal development based on Sui gas in Karachi. The Tarbela Project had been studied by Stone & Webster in 1964, mainly in the context of the Northern Grid area's power needs, and it had been found to have substantial advantages over a thermal-Kunhar alternative. The advantages of EHV interconnection had also been studied at that time, and it had been proposed in a preliminary way to link the various parts of the Province.

6.03 These two items -- Tarbela and interconnection -- represent the two most significant blocks of investment proposed for the power sector of West Pakistan over the next 20 years. It is only by reference to them that the validity of other proposed system developments can be assessed. This applies even to additions to the system made before either interconnection or Tarbela would come on line because most of the economic life of such additions would take place during the time that Tarbela and the EHV transmission network dominate the system. The Bank Group could not, therefore, ignore the necessity of reevaluating Stone & Webster's position on these issues before turning its attention to other dependent parts of the program -- particularly in view of the crucial role played in their studies by the Mari gas reserves and the recent large downward revision in the estimate of reserves available there.

The Value of Tarbela's Power Benefits

6.04 In order to establish the value of Tarbela's power benefits, Stone & Webster prepared an alternative thermal program as part of their 1964 report on Tarbela. This alternative system included a hydroelectric

project on the Kunhar River (a tributary of the Jhelum) and a 380-kv interconnection between Mari and the North so that advantage could be taken of the gas reserves at Mari.

6.05 The Kunhar River development would include hydro units having a total installed capacity of 560 mw in two stations 12 miles apart. The plants would operate at relatively high heads and would be less sensitive to reservoir fluctuations than either Tarbela or Mangla. The minimum capability of 491 mw would be expected in May because of low river flow and drawdown of the reservoirs which have relatively small storage capacities. The maximum capability of about 596 mw would occur in July. Sufficient water would be available from inflow and storage to permit an annual utilization of the plants at a capacity factor of about 56 percent.

6.06 The steam capacity at Mari, totaling 756 mw, would consist of two units of 142 mw each and two of 236 mw each.

6.07 The combined maximum and minimum capabilities of all of the new capacity in this alternative program amount to 1,352 mw and 1,297 mw respectively. The total installed capacity on the system would be as set out below:

Table 61

Installed Capacity in the Stone & Webster Thermal Alternative
(mw)

Existing	497
Scheduled 1965-74	1,655
Proposed 1975-85	1,316
	3,468

6.08 Stone & Webster calculated the investment and operating costs that would be involved over the years 1970-2015 in a program including Tarbela in 1975 and in the above described 'thermal alternative' program. To effect a meaningful comparison of the two cost streams, the time distribution of the costs was taken into account by calculating the 1965 values of the alternative cost streams using a discount rate of 8 percent.

6.09 The present worth of the cost of this thermal system, which Stone & Webster considered the most favorable alternative for meeting the system demand for both energy and power, amounted to US$205.8 million. This represented the gross power benefits of Tarbela. The net power benefits, being the difference between the power cost with Tarbela and the cost of the thermal Kunhar alternative, amounted to approximately US$80 million.

Table 62

Present Worth as of 1965 of Estimated Costs of Alternative Power Programs
(US$ million equivalent)

Discount Factor	Net Cost with Tarbela a/	Net Cost with Thermal-Kunhar Alternative
8%	124.6	205.8

a/ Excluding cost of main reservoir structures which was assumed to be allocated entirely to irrigation for purposes of this comparison.

6.10 The Bank Group made use of the basic elements of Stone & Webster's 'thermal alternative' program to build up several programs excluding Tarbela for purposes of comparison with programs including Tarbela. The resultant programs are described in detail in Annex 7 to this volume. Briefly, one included Kunhar commencing 1974, another Kunhar commencing 1981, and the third was, except for the existing hydroelectric plants, Mangla units 1-8 and Warsak units 5 and 6, a pure thermal alternative. In consideration of Kunhar, the Bank Group took into account two special side benefits that the project may have. First, it would provide about 0.4 MAF of live storage capacity and if the water were released at the right time it could improve downstream irrigation supplies. Second, regulation of the Kunhar River, a tributary of the Jhelum, could increase the capability of the Mangla power units in the critical period from March through May.

6.11 The Bank Group was anxious to gain an impression of the sensitivity of the power benefits of Tarbela to different assumptions regarding the prices of resources used in the power sector. Sudden changes can occur in the price and relative scarcity of such resources. Moreover current financial prices may not necessarily represent the economic sacrifice incurred by Pakistan in devoting these resources to the power sector rather than to other sectors, and there is certainly room for dispute about the prices that would represent adequately the sacrifice involved. The Bank Group focused especially on fuel and foreign exchange resources, and it compared the costs of the alternative power programs discussed above under different assumptions regarding fuel prices and the foreign exchange rate. The main fuel that will be used for power generation over the next 10-20 years is natural gas, and the Bank Group adopted, for purposes of this sensitivity testing, a wide range of natural gas prices which was intended to span all the prices that might be considered relevant from an economic or financial viewpoint over the next two decades. Differentials between gas prices in different parts of the Province (e.g. at the well head or elsewhere) were omitted from consideration in this part of the analysis, except when comparisons were made in terms of the current financial prices actually paid by the utilities for natural gas. Several alternative prices of foreign exchange were also used, but prime attention was given to comparisons at the current official exchange rate and at a 'scarcity' rate twice the current rate, which was intended to approximate more closely the scarcity value of foreign exchange in Pakistan. Costs of all alternative programs were discounted to 1965 at 8 percent interest rate.

6.12 The Bank Group's analysis indicates that inclusion of the additional and somewhat uncertain side benefits that may be attributable to

the Kunhar Project had an important effect on the relative attractiveness of the project. For instance, calculations at the current foreign exchange rate show that, if the side benefits of Kunhar are taken into account, then programs including Kunhar appear preferable to the pure thermal program at or above a fuel price of about 40 cents per million Btu; however, if the side benefits are omitted from consideration, then the thermal program remains the preferred one up to a fuel price of about 55 cents. But, even with inclusion of the additional benefits, Kunhar does not appear very attractive when foreign exchange costs are valued at the scarcity value of foreign exchange. Then it is only the program including Kunhar in 1981 which is at all competitive with the thermal program and then only at a fuel price above 55 cents per million Btu. When fuel is valued at approximately the prices paid by the electric utilities in 1965, programs including Kunhar appear preferable to the thermal program only when foreign exchange is also valued at the current official rate.

6.13 Having developed 'cheapest alternative" programs under the different economic assumptions with regard to the price of fuel and of foreign exchange, the Bank Group went on to compare them with two alternative programs including Tarbela in 1975. One of the Tarbela programs excludes interconnection and therefore phases the introduction of hydro units at Tarbela roughly in accordance with the capacity of the Northern Grid to absorb additional hydro energy, while the other includes interconnection and therefore brings in the Tarbela units more rapidly.

6.14 The Bank Group found that power programs including Tarbela in 1975 with or without interconnection, are substantially cheaper, in terms of discounted present worth, than the cheapest alternative discussed above at all fuel prices above 20 cents per million Btu. A range of fuel prices between 20 cents and 70 cents had been used for purposes of analysis. The net power benefits attributable to Tarbela are very sensitive to changes in assumption with regard to fuel price ranging from about $40 million at a fuel price of 20 cents per million Btu to about $220 million at a fuel price of 70 cents, with calculations using the current foreign exchange rate. They are less sensitive to changes in assumption regarding foreign exchange rate. This is indicated by comparisons in terms of current fuel prices: then Tarbela's net power benefits appear to be of the order of $120 million when foreign exchange is valued at the current rate and $110 million when foreign exchange is valued at the higher shadow rate.

6.15 The Bank Group believes, however, that a figure of $110-$120 million tends to underestimate the true power benefits of Tarbela when calculated in this way. Its studies suggest that current prices for thermal fuel in West Pakistan, while above the current scarcity value of fuel, fail to indicate the scarcity value of fuel that may, with present knowledge regarding the Province's natural resource base, be anticipated in the future. Indigenous fuel reserves are in many ways like a foreign exchange reserve because if they do not exist or if they are exhausted then foreign exchange must be spent for fuel imports. Annex 5 to this volume tries to quantify this scarcity value of fuel. When proper weight is attached to this aspect of the situation, then the net power benefits attributable to Tarbela would be of the order of $150 million.

The Timing of Tarbela

6.16 Besides studying the overall merits of the Tarbela Project, the Bank Group also gave some attention to the consequences, for power and for irrigation, of a delay in its construction. For this purpose the Bank Group devised a hypothetical alternative surface storage and power development program to the one including Tarbela in 1975, Sehwan-Manchar in 1980 and the raising of Mangla about 1988. This alternative would incorporate Raised Mangla and Sehwan-Manchar by 1975, with the completion of Tarbela delayed to 1985. Both programs would theoretically produce equivalent amounts of irrigation water and of electric power, so that the benefits of the alternative programs would be about the same. 1/ The amounts of irrigation water provided conform to the requirements projected by the irrigation consultant, while the amounts of electric power produced are sufficient to meet the power consultant's forecast of systemwide basic load together with the irrigation consultant's revised forecast of pumping loads. The alternative program comparisons are described in detail in Annex 7.

6.17 From the power point of view, postponement of Tarbela from 1975 to 1985 would involve very extensive thermal development and a heavy draft on the Province's reserves of natural gas, about 600-700 trillion Btu, or about one-tenth of the Province's main useable reserves of gas as currently estimated. The price attributed to this fuel is therefore of crucial importance in the comparison. The Bank Group worked up an approach to this matter which would take account, on the one hand, of the scarcity of indigenous thermal fuel in West Pakistan and, on the other hand, of the various alternative uses (i.e. other than for generation of electric power) that exist for it. At the same time, the Bank Group's approach tried to take into account the time when the fuel might be used either for power generation or for other purposes. Because of the uncertainty which inevitably attaches to the amount of fuel reserves available in the Province the Bank Group worked in terms of the 1966 estimates of natural gas reserves and also of a hypothetical reserve 30 percent larger in total size (resulting, say, from discovery of an additional two trillion cubic feet of gas at Sui). For this reason two sets of figures are presented below -- one appropriate to the 1966 estimates of gas reserves and the other appropriate to the hypothetical level of reserves.

1/ The power load forecast of the program with Tarbela in 1985 is actually somewhat higher than the load forecast adopted for the other program, because the irrigation program modeled around completion of Tarbela in 1985 takes advantage of the great flexibility in irrigation water supplies that will be provided by the large numbers of tubewells that will be in existence by then. Thus it compensates for the lack of Tarbela water in the period 1975-85 partly by overpumping, as well as by including early raising of Mangla and somewhat earlier scheduling of the small Sehwan-Manchar storage project. However, the net amounts of irrigation water and electric power produced by the two programs are equal.

6.18 Since the alternative programs are presumed to have equivalent benefits it is possible to focus attention entirely on their cost and thus on the extra costs that might result if the construction of Tarbela were delayed. Table 63 compares the present-worth costs of the alternative joint irrigation and power programs under different assumptions with regard to the scarcity of fuel and the value attached to foreign exchange.

Table 63

Present-Worth Costs of Surface Storage-Power Programs Including Tarbela in 1975 or 1985 a/
(US$ Millions)

	Latest Estimate Gas Reserves		Hypothetical Gas Reserves b/	
	Current Exch. Rate (Rs 4.76=$1)	Shadow Exch. Rate (Rs 9.52=$1)	Current Exch. Rate (Rs 4.76=$1)	Shadow Exch. Rate (Rs 9.52=$1)
Tarbela 1975				
Surface Storage Program c/	489	782	489	782
Power Program	795	1,104	674	983
Total	1,284	1,886	1,163	1,765
Tarbela 1985				
Surface Storage c/ d/	472	714	472	714
Power Program	915	1,220	767	1,072
Total	1,387	1,934	1,239	1,786
Saving attributable to completion of Tarbela in 1975 instead of 1985	103	48	76	21

a/ Costs discounted at 8% to 1965, economic fuel prices.
b/ 30% greater than latest estimate of gas reserves.
c/ Including all costs of main reservoir structures.
d/ Including some overpumping to compensate for lack of Tarbela.

6.19 These figures suggest that at an economic fuel price based on the 1966 estimates of gas reserves and at the scarcity value of foreign exchange used in this report the cost of delaying the construction of Tarbela from 1975 to 1985 would be in the order of $48 million in present-worth terms. Even if gas reserves could be firmly assumed to be at the higher level, the cost of delay would still be substantial --

at about $21 million. When foreign exchange expenditures are valued at the current official rate of exchange the costs involved in a delay of Tarbela from 1975 to 1985 appear considerably higher; the substantial overpumping required to help make up for the lack of Tarbela on the irrigation side and the heavy draft on natural gas reserves involved on the power side show up more clearly because the large foreign exchange component in the capital cost of Tarbela is weighted less heavily.

6.20 The validity of this comparison between alternative joint storage and power programs does, of course, rest on the assumption that if Tarbela were delayed, then the alternative program would be implemented. The Bank Group believes that the comparison presented is valid for purposes of an economic evaluation of the cost of postponement of Tarbela. Many of the components of the alternative such as High Mangla and the public tubewell schemes have received considerable study in Pakistan. In combination it appears reasonable to assume that the alternative would be capable of meeting the irrigation requirements projected by the irrigation consultant for the period 1975-85 even in years of low flow. It is true that there seem to have been some historical years on the Jhelum when kharif flows would have been inadequate to fill High Mangla, if drawn down to 1040 feet as assumed here, while at the same time meeting the kharif irrigation requirements of the Jhelum-fed canal commands as projected by the irrigation consultant for 1985. However, it is reasonably certain that both the filling requirements and the kharif irrigation requirements could be fully met in the earlier years when the kharif irrigation requirements are smaller, and by the later years -- say 1980-85 -- when the extensive public tubewell fields could provide a sizeable amount of flexibility for coping with years of low flow.

6.21 While the Bank Group thinks that it is quite possible that if such an alternative storage and power program were studied, it would be found to be technically feasible, it does also believe that the Tarbela Project has a degree of security attached to it that cannot be matched by alternatives. In the first place it has been thoroughly investigated so that, once the decision is made to complete it, it can be anticipated with a fair degree of certainty that its contribution to power and to irrigation supplies will indeed become available eight years later. In the second place, the project is inherently so large in its contribution to power and irrigation supplies that it provides a substantial margin for meeting unanticipated growth in demand.

6.22 In sum, then, the Bank Group believes that the figure of $48 million, in present-worth terms, is a reasonable valuation of the savings to be obtained from completing Tarbela in 1975 rather than in 1985, excluding the additional value that should be attached to the greater degree of security that adheres to the realization of the Tarbela Project. At the same time it should be borne in mind that the alternative program used as the basis for this comparison is the cheapest of several

alternatives investigated and is also, in itself, a carefully coordinated whole. The figures presented therefore indicate the present worth of the additional costs incurred as a result of choosing the alternative program rather than the program with Tarbela in 1975. Interim delays in completion of Tarbela of five or six years, resulting from delays in final selection and financing of any coordinated program would be considerably more costly.

The Reservoir Drawdown Levels at Tarbela and Mangla

6.23 Maintenance of higher or lower drawdown levels at Mangla and Tarbela will affect the amount of complementary thermal capability required to meet loads in the spring. Figures for hydro capability and energy output used here differ insignificantly from those used in Chapter V and are discussed in more detail in Annex 6. Sacrifice of 400,000 acre-feet of potential rabi irrigation supplies from Mangla, by raising the minimum drawdown level from 1040 feet to 1075 feet, results in raising the head on the Mangla turbines throughout the critical period by 35 feet and consequently increasing the firm capability of eight units at Mangla by about 140 mw. The irrigation consultant's final release pattern for Mangla envisages releasing all the stored water destined for irrigation by the end of March and commencing filling in May. Therefore the period of minimum capacity will last from the end of March through the beginning of May. At Tarbela, the firm capability of 12 units can be increased by about 270 mw by sacrificing 600,000 to 700,000 acre-feet of potential initial live storage capacity and keeping the minimum reservoir level up to 1332 feet instead of the minimum design level of 1300 feet. The irrigation consultant's final Tarbela release pattern envisages maintaining about 5 percent of live storage in Tarbela beyond the first of May. Consequently, the period of minimum capability at Tarbela will occur at the end of May and beginning of June, before filling has commenced. However, according to the Bank Group's calculations, the increase in capability at Mangla due to early filling there will increase capability at Mangla by the end of May by a greater amount than the Tarbela capability will be reduced as a result of final releases. Therefore, with the reservoir release patterns and the pattern of monthly peak loads used in these studies, the critical period for the system as a whole will shift from late March (where Mangla will put it) to the first ten days of May after installation of the first 4-6 units at Tarbela. The Bank Group estimates that the increase in firm capability at Tarbela in the first ten days of May resulting from maintenance of the 1332 feet drawdown level instead of 1300 feet will be about 230 mw.

6.24 Alteration of the drawdown levels on the reservoirs will also have some effect on the energy available from the hydroelectric installations. The overall net effect of the higher drawdown level on the energy available from eight units at Mangla in the mean year would be to raise it some 250 million kwh. Most of this increase would occur in conjunction with the higher capabilities in the critical period. A relatively small increase in energy output would occur in the flood months as a result of the higher head maintained

during the filling period and there would also be some relatively insignificant reductions in energy output in late winter as a result of reduced releases. Similarly, maintenance of the higher drawdown level at Tarbela would add significantly to energy available in the critical period April-July at the end of rabi and beginning of the filling period, and slightly reduce the energy available in the winter months November-March as a result of reduced releases. The net effect on the total amount of energy available annually from Tarbela with twelve units under mean-year conditions would be a relatively slight increase of about 300 million kwh.

6.25 The Bank Group focused its attention simply on two alternative drawdown levels at Mangla -- 1040 feet and 1075 feet -- and two at Tarbela -- 1300 feet and 1332 feet -- in order to secure an indication of the relative priority, in terms of benefits, that should be attached to the needs of agriculture and of power in long-term planning. The fact that the minimum capability of each generating unit is higher with the higher drawdown level means that less complementary thermal capability has to be provided, and so a number of alternative power programs were prepared, differing little except insofar as more or less thermal capability had to be installed to provide sufficient total generating capability to meet peak loads. These programs were then tested on the computer simulation model (see Annex 10), which calculated the present worth of total system costs for the alternative programs for the period 1966-85. The difference between the present-worth costs of the alternative programs give an indication of the power savings to be derived by maintaining a higher drawdown level over the period 1968-85 in the case of Mangla and 1975-85 in the case of Tarbela. The present worth of agricultural benefits which might accrue from releasing additional amounts of stored water from the reservoirs over the same periods were estimated on the basis of shadow prices implicit in the Bank Group's linear programming analysis of investments in irrigation discussed in Part II of the Economic Annex. This analysis considered a number of different means of improving irrigation supplies to each of some fifty different areas in the Indus Basin and took account of the interaction of a variety of constraints on development, some specific to each canal command and some more general such as the total number of public tubewells that might be installed in a given period, the total amount of surface water available during the rabi season when water is scarce, and the total amount of foreign exchange available for use in agriculture. The initial assumption made with regard to the availability of surface water in the rabi season was consistent with a 1040 feet drawdown level at Mangla and a 1332 feet drawdown level at Tarbela. Since the total amount of surface water available in the rabi season was a specific constraint in the analysis, the program generated not only a list of canal commands which could best be developed under any particular set of conditions but also shadow prices on surface water -- or, in other words, prices representing the value of the additional production that could be obtained (or the savings on other types of irrigation development that could be realized) if the total amount of surface water supply were increased. The program also generated figures on the loss

of production (or extra costs of alternative irrigation developments) that would be sustained if the supply of surface water in the scarce-water period were reduced. It was assumed that any increases or reductions in the total amount of surface water available would be spread over the course of the scarce-water period in accordance with the reservoir release patterns developed by the irrigation consultant for each reservoir.

6.26 This type of approach gives a broad indication of the general order of priority that should be attached to power and to agriculture in the use of marginal amounts of stored water. The Bank Group's analysis confirms the results of other studies in that it indicates a high marginal value for additional supplies of irrigation water especially in the decade 1965-75. The present worth to agriculture of drawing down Mangla to 1040 feet instead of 1075 feet during the period 1968-75 (i.e. supplying about 400,000 additional acre-feet of irrigation water every year) is estimated at $20 million. After 1975, the value of additional water declines due to the increase of rabi water supplies from Tarbela and the possibility of greater reliance on overpumping. Thus the value of the same amount of irrigation water resulting from the lower drawdown level during the decade 1975-85 is estimated at $1.5-8.0 million depending on whether Sehwan-Manchar is completed by 1980 or after 1985. Thus for the whole period 1965-85, the present worth of benefits to agriculture from operating Mangla at 1040 feet instead of 1075 feet is $22-28 million. The comparable figure for the present worth of benefits to power of operating Mangla at 1075 feet instead of 1040 feet during 1968-85 is estimated at $20 million. This saving results largely from the postponement of other system developments which the 140 mw of additional capability at Mangla would make possible. The evidence of these figures indicates that, at least during the first ten years of the period, greater benefit will be derived from operating Mangla with the lower drawdown level rather than the higher one.

6.27 Similar figures for the present worth of benefits to power and to agriculture of alternative allocations of marginal quantities of Tarbela's storage capacity stand in contrast to those given above for Mangla and indicate quite strongly that Tarbela should be operated, at least over the period 1975-85, to the higher rather than the lower drawdown level, as far as can now be foreseen. The present worth to agriculture of drawing down Tarbela to 1300 feet instead of 1332 feet during the decade 1975-85 (i.e. supplying about 600,000 to 700,000 acre-feet of additional water every year) is estimated at $19 million, assuming that Tarbela is the only addition to surface water storage during that decade. However, if account is taken of the possibility of overpumping due to the existence of extensive tubewell fields at that time, the value of the marginal water supplies from Tarbela would decline to $11-15 million and even lower if Sehwan-Manchar were to be completed by 1980.

6.28 The comparable figure for the present worth of benefits to power of operating Tarbela at 1332 feet instead of 1300 feet during 1975-85 is estimated at $19 million. This saving results largely from the postponement of additions to generating capacity which is made possible by each Tarbela unit having a capacity of at least 70 mw at the time of system minimum capability instead of 50-53 mw. It is also due to the eventual saving of 250 mw in complementary thermal generating capacity that the maintenance of the higher drawdown level would make possible when all twelve units at Tarbela are installed. Thus the figures cited above suggest operating Mangla at the lower drawdown level of 1040 feet, especially during the decade 1965-75. On the other hand, they indicate that Tarbela should probably be operated at the higher drawdown level of 1332, at least during the decade 1975-85.

6.29 However the Bank Group strongly feels that decisions regarding drawdown levels at Mangla and Tarbela should not in practice be set firmly for ten-twenty year periods, as the above discussion has implied. One of the most important benefits that these large reservoirs will confer on the irrigation and power systems of West Pakistan is a wide measure of flexibility. Each reservoir could theoretically be operated to a different drawdown level in each year, depending on the specific situation regarding demands for irrigation water and for electric power and regarding alternative supplies of each. In practice it will be necessary to plan some three years ahead for a certain drawdown level in order to ascertain what additions must be made in the interim to the irrigation system and to the power system in order to meet demand. This short-term planning should be carried out on the basis of a careful evaluation of the alternatives that exist for the year in question. The global benefit figures given in the preceding paragraphs in fact conceal tremendous variations over the years in the benefits of maintaining the higher or the lower drawdown level. In some years for instance, the additions to power system capability will be much more expensive in capital cost than in other years. Therefore, the postponement in system additions which maintenance of the higher drawdown level will make possible will mean a much more significant cost saving in some years than in others. Some instances of what appear from present perspective to be years when high savings could be had from maintaining the higher drawdown level at Mangla are discussed in the section below about the Power Program. Examples are 1971, when maintenance of 1075 feet at Mangla might enable a one-year postponement of a transmission tie between the North and Mari, and 1975 when the first units at Tarbela may not be quite ready by the critical period of the year, according to the latest TAMS construction schedule.

6.30 There is one other critical component that must go into short-term decisions about the drawdown levels to be maintained at Mangla and Tarbela: assessment of hydrological uncertainty and of the effects that would result from a need to change the planned drawdown level at short notice because of unexpectedly high or low flows in the rivers. Inclusion of this aspect in the decision making process may well prompt planning for maintaining a higher drawdown level than would otherwise

be the case. For instance,1975 was mentioned above as a year when it might be desirable to plan for operating the Mangla Reservoir to a drawdown level of 1075 feet. But what if no Tarbela water were available and the year also proved to be one of low rabi flows? It would probably be necessary to diverge from the plan and to release all the water stored at Mangla. Table 64 indicates the extent to which actual hydroelectric capability could, as a result, fall short of planned hydroelectric capability by ten-day periods and compares these unexpected shortages with projected systemwide peak demand in the same months. This table does not take account of reserve capabilities. It shows that in order to meet peak loads in 1975 complementary firm thermal capability of about 1414 mw would be needed if Mangla was drawn down to 1075 feet. If, instead, Mangla had unexpectedly to be drawn down to 1040 feet then shortages of firm capability would occur in the ten-day periods underlined in the bottom line of the table (i.e. the periods when complementary thermal capability required exceeds that which would be provided in planning for 1075 feet minimum drawdown level). The evidence of this table is that, disregarding reserves, load might have to be shed in three ten-day periods. The maximum amount of load shedding required would be about 150 mw, or about 8 percent of systemwide peak load in March 1975. According to available daily load curves for the WAPDA Grid System and for Karachi the top 8 percent of daily peak lasts barely two hours -- between 7 p.m. and 9 p.m. in the North and between 8 p.m. and 10 p.m. in Karachi. Two hours of shedding 150 mw each day for ten days (possibly less if diversity of peaks is taken into account) and a smaller amount of shedding for say one hour a day for twenty days is apparently the price that would have to be paid for the saving obtainable from postponing a substantial investment in generating capability (and possibly transmission) for a year or two. Moreover this takes no account of the approximate 200 mw of reserve capability that the proposed power programs include for 1975. These figures appear to argue in favor of planning for 1075 feet at Mangla in 1975, and probably in other years, with a readiness to lower the drawdown level and take up the slack in reserves or in load-shedding should the year turn out to be one of low rabi flow.

EHV Interconnection Between the Major Power Markets

6.31 Both Stone & Webster and Harza have recommended that the major power markets of West Pakistan be linked by EHV transmission lines in the early 1970's and both based their recommendations to a significant extent upon the assumption that substantial reserves of natural gas were available at Mari with little use for purposes other than power generation. Since they carried out their analysis the best estimate of total gas reserves at Mari has been revised heavily downward from about 5 trillion cubic feet to about 1.8 trillion cubic feet. Moreover the Bank Group takes the view that there do exist alternative uses for Mari gas of considerable potential importance, particularly for the production of badly needed fertilizer. For these reasons the Bank Group has focused attention mainly on the overall justification for

Table 64

The Effect on Total Hydroelectric Capability of Planning for 1075 feet at Mangla in 1975 and Subsequently Changing to 1040 feet a/
(mw)

	March			April			May		
	1-10	11-20	21-31	1-10	11-20	21-30	1-10	11-20	21-31
Peak Load	2093	2093	2093	1984	1984	1984	2051	2051	2051
Hydroelectric Capability (with 1075' at Mangla)									
Small Hydro	75	75	75	85	85	85	85	85	85
Warsak 1-4	100	100	100	160	160	160	160	160	160
Mangla 1-8 (1075')	656	584	504	504	504	504	504	624	705
Total Hydro	831	759	679	749	749	749	749	869	950
Complemantary Thermal	1262	1334	1414	1235	1235	1235	1302	1182	1102
Hydroelectric Capability (with 1040' at Mangla)									
Small Hydro	75	75	75	85	85	85	85	85	85
Warsak 1-4	100	100	100	160	160	160	160	160	160
Mangla 1-8 (1040')	544	472	360	360	360	360	360	496	624
Total Hydro	719	647	535	605	605	605	605	741	869
Complementary Thermal	1374	1446	1558	1379	1379	1379	1446	1310	1182
Potential Load-Shedding		112	144				144		

a/ This table is based on the conservative figures for the capability of the Mangla turbines at low reservoir levels used for planning power generation programs in this report. The estimated capabilities of the Mangla units are given as of the minimum-day in the ten-day period (i.e. last day during release season and first day during filling season).

380-kv interconnection, the timing of the interconnection if justified, and the effect that the EHV interconnection might have on the need for expansion of gas pipeline capacity to supply fuel from Sui for thermal generation in the Northern Grid area and Karachi.

6.32 The Bank Group conducted most of its studies of the EHV transmission question in terms of three alternative power development programs which it devised. All included the Tarbela Project completed in 1975. One was based on the assumption that the major power markets would be initially linked with a 380-kv transmission line in 1971 and that an eventual total of 1100 mw of thermal generating capability would be developed in the vicinity of the Mari gas field. Additional 380-kv transmission lines would be added over the years in a manner similar to that recommended by Stone & Webster. The second program was based on much the same assumptions regarding 380-kv transmission lines (though with some difference in scheduling of the later lines), but it included thermal development at Mari only to an ultimate level of 400 mw; lack of Mari capability, as compared with the first program, is compensated by additional thermal capability in the North and in the South fired by Sui gas. The third program excluded interconnection altogether and kept each power market self-sufficient, developing enough thermal capacity at Mari merely to meet local (Upper Sind) loads. A full description of these alternative programs and of the analyses performed with them is given in Annex 9.

6.33 In comparing these alternative programs, the Bank Group made calculations on the basis of current financial prices for natural gas in the different areas of West Pakistan and also on the basis of the time-series of economic fuel prices developed in connection with analysis of the Tarbela Project (see paragraph 6.17 above). It found that on either basis its analyses confirmed the doubts raised by Stone & Webster (see paragraph 5.69 above) regarding the validity of EHV interconnection if thermal development at Mari must be limited to 400 mw. When financial fuel prices were used, the program including interconnection and 400 mw at Mari appeared slightly cheaper than the program without interconnection in terms of present worth of total system costs if foreign exchange was valued at its current official rate but not cheaper if foreign exchange was valued at the shadow price of twice the current rate. When fuel was priced in terms of its estimated economic value and allowance was made for the costs of gas pipeline capacity required under the different programs to carry fuel from Sui to thermal generators in Karachi the program with interconnection and 400 mw at Mari, looked, if anything, more marginal. Therefore the conclusion was drawn that if only 400 mw of thermal generation can be developed in the center of the Province, then the whole concept of linking the power markets by EHV transmission lines should be very carefully reexamined.

6.34 However the Bank Group's studies did show that a program including interconnection and 1100 mw of thermal capability at Mari would have significant, though still small, advantages over a program excluding interconnection. This conclusion too was not very sensitive

to the fuel prices, financial or economic, used in the analysis. The program including interconnection showed savings over the program without interconnection with a present worth of the order of $20-25 million when foreign exchange costs were valued at the current exchange rate and of about $10-15 million when foreign exchange costs were valued at the shadow rate.

Use of Sui Gas for Power Generation

6.35 The Bank Group's studies of alternative uses of natural gas indicate that, with reserves as best estimated in 1966, it would appear reasonable to use substantial amounts of Sui gas over coming years for firing the thermal plants which are a necessary complement to Mangla and Tarbela as sources of electric energy. Sui gas can either be converted into electric energy at the power markets, in which case additional gas pipeline capacity is required (as in the 'Without Interconnection' Power Program), or it can be converted into electric energy at Sui and the energy can be transmitted to market by wire. The above comparison of alternative power programs suggests that in West Pakistan, where an EHV line would be performing a major role in bringing hydro energy down to the South, it is preferable to concentrate at least a portion of Sui-fired generation close to well-head rather than to disperse it among the power markets to be served; the electric energy will then be carried by wire to the power market. Location of generation facilities at the Sui field itself would, however, involve construction of a special EHV tie across the Indus to link with the main Lyallpur-Mari-Karachi EHV transmission line as presently envisaged. The Bank Group notes that, of several alternative sites for Mari generation considered by Kuljian Corporation in 1965, the best was found to be on the left bank of the Indus, close to the Gudu Barrage, where advantage could be taken of the proximity of the river for cooling water supplies. This site is actually about midway between the Mari and Sui gas fields. The Bank Group estimates that the 45-mile 16-inch pipe from Mari to Gudu, required to supply fuel for a 125-mw thermal plant, would have a cost of about $4 million, without duties and taxes. Assuming that there would be no special difficulties involved in looping the section of the existing Sui-Multan pipeline which traverses the Gudu Barrage, the Bank Group estimates that a 45-mile 16-inch loop from Sui to the designated site for the 125-mw plant would have an economic cost in the neighborhood of $3 million. Addition of an allowance for pipeline links between Mari and Gudu and between Sui and Gudu would significantly reduce, but not eliminate, the present-worth cost advantage of the program with interconnection and heavy thermal development at 'Mari' over the program without interconnection.

Other Advantages of Interconnection

6.36 The Bank Group's analyses therefore indicate, on the basis of conservative assumptions, that provided about 1000-1100 mw of thermal generation fired by Mari or by Sui gas can be developed in the vicinity

of the gas fields, then a program including interconnection is more advantageous in terms of cost than one excluding it. Moreover there are certain definite advantages to interconnection which have not been taken into account in the above analysis. The most important of these concerns the problem that will arise in the pre-Tarbela years in providing sufficient fuel for thermal generation in the Northern Grid area if that area has still to generate all its own power requirements at that time. The second involves the overall saving in thermal fuel over the next twenty years that interconnection will make possible by widening the market for hydroelectric energy. The third allows for the fact that the EHV transmission lines proposed may well be able to carry more hydro energy southward than has been assumed in the analyses underlying the above discussion. Fourthly there are more general and intangible, but nonetheless important, advantages to interconnection such as the flexibility which it adds to the overall power system. These various matters are briefly discussed below, in turn.

Problem of Low Load Factor Thermal Generation

6.37 If the Mangla and Tarbela Dams are drawn down every spring to meet agricultural requirements of irrigation water, their capacity to produce electric power will fluctuate greatly over the year from a combined minimum of about 1200 mw in April-May1/ to a combined maximum of about 3600 mw in August. One consequence of this is that thermal installations in any areas supplied with hydroelectric power will generally have a rather poor annual load factor. This is particularly the case in the Northern Grid area, where the Bank's analyses suggest that the overall annual load factor on the thermal equipment existing or already sanctioned (i.e. excluding any additions to thermal capacity beyond the Lahore Gas Turbine envisaged for completion in March 1968) will be about 20-25 percent in each of the years 1969-74 and will be of the order of 10-15 percent in each of the years 1975-85. These are the load factors on thermal plant, assuming the existence of interconnection. Without interconnection they would fluctuate heavily from year to year and sometimes be worse.

6.38 It will be costly to supply fuel for low load factor operation of thermal equipment and this problem will be considerably more serious in the Northern Grid area without interconnection than with interconnection. The Bank Group's studies indicate that, with interconnection between Mari and Lyallpur in 1971, the peak-day thermal fuel requirements of the Northern Grid area will not rise above current levels before the late 1970's; but if interconnection is not provided at that time then peak-day fuel requirements will rise, in terms of natural gas, from a level of about 60-70 MMcf in 1966 to about 100-120 MMcf in 1972-74. In the recent past WAPDA has drawn most of its thermal fuel supply from the Sui gas field. It is an open question whether it will remain economic to supply

1/ Assuming drawdown levels of 1332 feet at Tarbela and 1040 feet at Mangla.

a large proportion of the highly peaked fuel requirements that WAPDA will have after completion of the first few units at Mangla via the pipeline rather than to use more of the existing pipeline capacity for meeting the gas requirements of other consumers. The Bank Group estimates that to meet all the peaks of the without interconnection case by direct supply from Sui would require expansion of the pipeline by about 40 MMcf per day, at an economic cost of $6 million. A cheaper solution would in fact probably be found. However, no suitable sites for storage of gas in the North seem to exist, and it will probably be necessary to resort to use of fuel oil, which is costly in foreign exchange and expensive to transport to the North. Thus it is a marked advantage of a 'with interconnection' program, not fully taken into account in the quantitative economic analysis referred to above, that it reduces the amount of thermal generation that will be necessary in the North.

6.39 The effect of interconnecting the Northern Grid area with Karachi-Sind will be, of course, greatly to worsen the load factor on the thermal plants in the South and therefore, the load factor on the natural gas pipeline which supplies them, assuming that the bulk of their fuel requirements will continue to be provided from Sui. Nevertheless the load factor on the gas-fired plant in the South will not, according to the Bank Group's estimates, drop below about 40 percent. The Bank Group's studies indicate that peak-day thermal fuel requirements of the Karachi-Hyderabad area, with interconnection in 1971, will reach a peak in 1970 which will not again be exceeded before the early 1980's. Therefore, no additional expansion of the pipeline in the South would be required after 1971 to meet the needs of the electric utilities, and in fact, the Sui Gas Transmission Company would probably make available to other consumers, as their demand grows, any pipeline capacity which becomes surplus to KESC's requirements. Moreover, there are two reasons why low load factor demand for thermal fuel will be less costly to Pakistan if it occurs in the South rather than in the North. First, imported fuel oil can be made available there at considerably less cost than in the North because use in Karachi eliminates the long rail haul. Second, there is a chance the Sari Sing gas field close to Karachi may be suitable for cheap conversion into a gas storage facility.

Heavier Draft on Natural Gas Reserves of 'Without' Interconnection' Program

6.40 Another factor which favors interconnection but which did not come out fully in the quantitative comparison of the 'with' and 'without' interconnection programs is the larger amount of thermal fuel, mainly natural gas, that will be required to generate electric power over the next twenty years if interconnection is not undertaken. Heavier consumption of gas arises mainly from two related causes. Firstly, without interconnection the Karachi-Hyderabad and Upper Sind power systems would remain purely thermal. In addition, the fact that the market for hydroelectric power would consequently be confined to the Northern Grid area means that it would not be economically justifiable

to bring in the hydro units as quickly as would be the case if a larger market were available to absorb more of their energy immediately it becomes available. The heavier fuel costs of the 'without interconnection' case did of course weigh in the comparison of total system costs cited in previous paragraphs. However the approach to economic fuel pricing used in this report is one that makes fuel prices higher over time as more is consumed and less remains for alternative non-electrical uses (see Annex 5). In fact the economic comparisons between programs with and without interconnection were all made on the basis of the fuel price series developed for the case of Tarbela completed in 1975. The total 1966-85 thermal fuel requirements of the program with Tarbela, interconnection and 1100 mw at 'Mari' are actually about 800 trillion Btu's; those of the program with Tarbela but without interconnection about 1150 trillion Btu's; and those of the program with Tarbela delayed to 1985 (see above paragraphs 6.17-6.23) about 1500 trillion Btu's. Thus the lack of interconnection does make a significant difference to the total amount of thermal fuel required and recalculation of the total economic costs in terms of a more finely tailored set of fuel prices would show that the 'without interconnection' case is even more costly in present-worth terms than implied by the figure used to calculate the present-worth cost savings of interconnection in paragraph 6.34.

Capacity of Transmission Lines for Carrying Hydro Energy South

6.41 The discussion of the 'with interconnection' programs in the above paragraphs was all on the basis of cost calculations made on the assumption that the transmission lines would not be able to carry power in excess of their 'firm capability'. 'Firm capability' was defined as the capability of a transmission line with one line-section being out of service. Thus, for instance, when two single-circuit lines exist between Mari and Lyallpur, their firm capability is taken as the estimated physical capability of one line. This is a correctly conservative approach to the basic analysis of transmission lines, particularly when the transmission line is responsible for bringing firm power to market. However, analyses have also been made on the basis of the physical capability of the transmission lines, particularly to see what effect that would have on the absorption of hydro energy. In practice use of the maximum physical capability of the transmission lines will probably be worthwhile for carrying to the South hydro energy excess to the requirements of the Northern Grid, though it might involve installation of extra relays and maintenance of some additional spinning reserve in the South. Analyses on the basis of the maximum physical capability of the transmission lines indicated that the fuel savings made possible by the availability of more hydro energy in the South would have a present worth of about $10 million, when calculations were made on the basis of the economic fuel price series appropriate given current estimates of natural gas reserves; at the lower economic fuel price series the present worth of the fuel savings would be about $5 million. These should be considered an additional benefit to the 'with interconnection' program, but they should probably have some risk factor attached before inclusion with benefits previously discussed.

6.42 Finally there are other benefits to interconnecting the power systems of West Pakistan which are of a more general nature and non-quantifiable but nevertheless significant. Once the various small grids are linked together into a single system there will be more room for maneuver in the operation and more flexibility. Unanticipated loads will be more readily assimilable and unexpected delays in completion of new generating plants will cause less disruption as the reserves of other parts of the system are called in to fill the gap, or shortages s are spread wider and thinner. As the power consultant puts it, "Experience has shown that developments of the nature here proposed (i.e. 380-kv interconnection between power markets) contain additional benefits which usually are not foreseeable at the time the decision to move ahead is made".

The Timing of Interconnection

6.43 Having reached the general conclusion that interconnecting the power markets of West Pakistan is economically worthwhile, the Bank Group went on to direct its attention to the specific question of the timing of the initial steps in interconnection. Stone & Webster had recommended that the first 380-kv tie be made between Karachi and Mari in 1971 and the second between Mari and Lyallpur in 1973. They recommended early completion of the Karachi-Mari line in order to eliminate the need for further additions to generating capability in Karachi between completion of the 125-mw Korangi C unit in 1969 and the time when the AEC nuclear plant may assume reliable operating status in 1972 or 1973. They chose 1973 for the first link between Mari and Lyallpur in order to eliminate the need for further capacity additions in the North between completion of Warsak units 5 and 6 and Mangla units 5 and 6 in 1970-72 and the scheduled completion of Tarbela units 1 and 2 in 1975. The Bank Group believes that the concept of concentrating additional thermal development in the late 1960's and early 1970's in the Mari area and thereafter connecting the North and the South to Mari as and when they require additional capability is correct. About 200 mw of capability at Mari will be required to charge the 380 kv-transmission lines and 200 mw will account for about half of all the additional thermal capability required on the system in the early 1970's if interconnection is provided. Concentration of system additions during the Fourth Plan period at Mari, being in the center of the Province, will add to the flexibility which is one of the potential benefits of interconnection.

6.44 The Bank Group agrees with Stone & Webster that the first EHV line between Mari and Karachi would be warranted in 1971, but it believes that the first EHV line between Mari and Lyallpur may be of higher priority than the Mari-Karachi line and of higher priority than Stone & Webster assigned to it. The main reason for this view is that, t according to the Bank Group's analysis, the Northern Grid area will be short of capability by 1971 unless further thermal capacity is added there at that time. The Bank Group agrees with Stone & Webster that addition of thermal capacity in the North would be undesirable in view of

the need to concentrate capability at Mari for both line-charging purposes and the greater flexibility it would provide after Tarbela comes on line. The Bank Group finds a shortage in the North earlier than Stone & Webster partly because it believes that Warsak units 5 and 6 should be postponed until after the installation of the first four-six units at Tarbela (see below, para 7.20) and partly because it believes that the shortage of rabi irrigation water in the early 1970's may be so acute as to require that Mangla be fully drawn down to 1040 feet each year.

6.45 The Bank Group made several short-term comparisons between two different schedulings for initial EHV interconnection and variants of them, which are discussed in detail in Annex 9 to this volume. Basically one involves linking Lyallpur, Mari and Karachi in 1971 and the other involves postponing these initial links to 1974/75. The program including early interconnection proved somewhat cheaper, in present-worth terms, whether financial or economic fuel prices were used and whether foreign exchange was valued at the current rate or at the shadow rate. Variants were tried including one or two year postponements of the transmission lines but none had lower present-worth costs than the program with early transmission links. The main disadvantages of programs which postpone interconnection between Mari and Lyallpur are that they involve installing thermal capacity there which will be little used for a decade or more after completion of Tarbela Dam and that they involve special difficulties in regard to fuel supply in the Northern Grid in the early 1970's as mentioned above. The main disadvantages of postponing the link between Karachi and Mari are that some other measures would probably have to be taken to firm up the nuclear plant in 1971 and that total system fuel costs would be higher as less hydro energy could be absorbed.

6.46 The year 1971 may not be a physically feasible target date for the completion of EHV interconnection. The implications of the Bank Group's analysis are that delays beyond 1971 will result in loss of potential savings. However, there is somewhat more flexibility in practice than implied by the Bank Group's approach. WAPDA apparently plans to extend the existing double-circuit 132-kv line from Rahimyar Khan the additional 40-50 miles required to link the Northern Grid with Mari. According to the Bank Group's analysis this line would be able to carry enough power from Mari to the North to postpone the need for the 380-kv line by one year (see below, para 7.21). It would also be useful in later years as a supplement to the 380-kv line and for local transmission purposes. Therefore, while the Bank Group believes that priority should be given to introducing a 380-kv transmission system, it also feels that the effects of slight delays in execution -- of the order of a year or two -- could be overcome without excessive expense or disruption.

6.47 Unfortunately, the Bank Group has not been able to make a full analysis of how the case for interconnection would be affected by a different load forecast. As pointed out in Chapter IV, it believes that the section of the load forecast used here about which there is

greatest uncertainty is that for the North in later years. A higher load forecast was developed for the Northern Grid area to provide a range of expectations. Analysis on the basis of that load forecast would probably make interconnection look somewhat less attractive than it appears here, because one important factor favoring interconnection in the economic analysis was the limited capability of the Northern Grid area alone to absorb hydro energy. If Northern Grid loads turn out to be higher, then there will be somewhat less advantage gained from widening the market for hydro energy by interconnection. But larger Northern Grid loads could mean that it would be worthwhile to bring in the Tarbela units faster and to move on to a further hydroelectric project more rapidly than would otherwise be the case. Since the energy available from any project other than Kunhar is likely to be about as seasonally unbalanced as that from Tarbela and Mangla, the availability of a wider market to absorb more hydro energy in the flood months could be advantageous. Moreover the need for a link with Mari will be greater to the extent that Northern Grid loads are higher during the early 1970's than assumed in the basic load forecasts underlying this analysis.

380-kv vs. 500-kv Transmission

6.48 The comments of the Bank Group regarding EHV transmission in the above paragraphs have all revolved around subjects upon which Stone & Webster and Harza were jointly agreed -- i.e. the need for interconnection and the time when it should be implemented. The major difference between their recommendations is the voltage of the EHV interconnection. The Bank Group felt its major effort should be devoted to an appraisal of the overall situation regarding energy transmission, especially in view of the revised estimates of Mari gas reserves, rather than to the more technical question of the transmission voltage. As pointed out above, Stone & Webster recommended a 380-kv transmission system and the Bank Group conducted most of its studies on this basis. The consultant favored 380-kv transmission because he found it slightly cheaper in present-worth terms and because it had a number of operating advantages. Harza found that, taking into account the heavier transmission losses that their technical studies indicated would occur with 380 kv, the present-worth costs of 500-kv and 380-kv systems were about the same at discount rates between 6 and 8 percent. Their final judgment was in favor of 500 kv since they felt that the costs of 500 kv may decline more rapidly than the costs of 380 kv in coming years and power loads in West Pakistan might well grow more rapidly than presently anticipated. This issue is more fully discussed in Annex 9, but the Bank Group has not gone into it in detail. It finds the technical arguments of Stone & Webster in favor of 380 kv convincing; preliminary calculations also indicate that if the analysis discussed above had been carried out in terms of 500 kv, the substantial cost advantages of an interconnected over a non-interconnected system would be somewhat reduced because of the heavier early capital commitments of a 500-kv system. However, it should be noted that this is not a firm judgment on this matter.

Expansion of Gas Pipelines to Meet Fuel Requirements for Electricity Generation

6.49 The Bank Group's analysis indicates that it would be unwise to expand the capacity of the SNGPL 1/ pipelines in order to provide fuel for thermal generation, except on a purely temporary basis -- i.e. if the pipeline can be expanded initially to meet WAPDA's demands and the capacity can subsequently be taken up by other gas consumers. Peak-day requirements of fuel for thermal generation in the Northern Grid area were derived from the power system simulation which the Bank used for its studies. As pointed out in paragraph 6.38 these estimates indicated that, if electrical interconnection is completed in 1971/72 and thermal development concentrated near Mari, as recommended, then peak-day requirements of thermal fuel will not increase above their current level before about 1980. The Bank's studies have also led to the view that the overall load factor on thermal plant in the Northern Grid area will be very low. Both these factors appear to point against expansion of SNGPL pipeline capacity to meet any short-term peaks that may arise in the coming years due to delay in completion of Mangla units or of interconnection and rather suggest that it may be well to consider making available to other consumers some of the gas-pipeline capacity presently committed to WAPDA. Table 65 compares some of the detail derived from the power system simulation with estimates of future gas requirements of the Multan and Lyallpur plants used by SNGPL in one of their recent planning exercises. The left-hand columns give the figures used by SNGPL, while the two right-hand sets of columns show comparable estimates from the Bank Group's studies; one set for the load forecast which the Bank Group has adopted as basic and one set for the higher load forecast which the Bank Group considers suitable for contingency planning. These comparisons suggest that the WAPDA-SNGPL figures fail to show the full impact that Mangla may be expected to make on requirements of gas for electric power generation. The load factors implicit in the Bank's projections are lower than those implied by the WAPDA-SNGPL projections in almost every year; this is particularly true of the Multan Plant. Some of the differences in regard to this plant may arise from WAPDA's assuming that it cannot be operated at low loads. However the Bank Group shares the view of Stone & Webster that, despite the close clearances of the older two turbines at Multan, these must be operated for peaking purposes if West Pakistan is to make most economical use of its available resources; the operators should therefore be trained accordingly. It will be noted that, by contrast with the WAPDA-SNGPL figures, the Bank Group estimates always indicate a higher load factor on the Lyallpur plant than the Multan units because of the greater thermal efficiency that the Lyallpur units should have; there would also be less transmission losses. Besides the difference in load factors there are also considerable differences between the two sets of projections regarding peak-day fuel requirements, especially for the Multan plant. The Bank Group believes that the central set of figures in Table 65 gives a

1/ SuiNorthern Gas Pipeline Company.

Table 65

Projections of Gas Requirements of WAPDA Northern Grid Plants

	WAPDA-SNGPL			BANK GROUP MAIN LOAD FORECAST			BANK GROUP HIGH LOAD FORECAST		
	Ave-day MMcf	Pk-day MMcf	Load Factor (%)	Ave-day MMcf	Pk-day MMcf	Load Factor (%)	Ave-day MMcf	Pk-day MMcf	Load Factor (%)
Multan Steam Plant									
1967	44	70	63	10	38	26	13	42	31
1968	31	52	60	5	19	26	6	22	27
1969	41	56	73	4	24	17	7	32	22
1970	35	65	54	1	14	7	3	22	14
1971	23	62	37	7	36	19	12	39	31
1972	31	72	43	6	28	21	14	40	35
1973	37	77	48	5	34	15	16	42	38
1974	48	77	62	4	26	15	10	30	33
1975	27	74	36	5	33	15	11	39	28
1976	24	77	31	4	36	11	11	41	27
1977	41	77	53	4	34	12	8	39	21
Lyallpur Steam Plant									
1967	13	18	72	16	38	42	18	37	49
1968	12	17	71	12	29	41	14	29	48
1969	18	22	82	9	29	31	13	31	42
1970	21	33	64	3	26	12	5	27	19
1971	11	18	61	9	31	29	13	29	45
1972	13	33	39	9	36	25	13	35	37
1973	20	36	56	7	29	24	14	36	39
1974	17	36	47	7	24	29	11	21	52
1975	7	34	21	6	27	22	14	32	44
1976	6	34	18	4	32	13	13	29	45
1977	11	34	32	4	30	13	9	31	29

reasonable idea of the role that the Multan and Lyallpur plants will be called upon to play in coming years if the system is operated as efficiently as possible.

6.50 As regards the Southern gas pipeline system, it was pointed out above that one of the savings accruing to the power system from interconnecting the North and South would be elimination of the need for expansion of the Sui-Karachi pipeline to meet fuel requirements for power generation between 1970 and 1980. The Bank Group's studies indicate that the peak-day requirements of natural gas for power generation may rise between 1966 and 1970 from about 40 MMcf/day to about 75 MMcf/day. (See Figure 1.) They will subsequently fall as a result of introduction of the Karach

PEAK AND AVERAGE DAY GAS REQUIREMENTS FOR THERMAL GENERATION IN THE SOUTH : WITH AND WITHOUT INTERCONNECTION

(MMcf PER DAY)

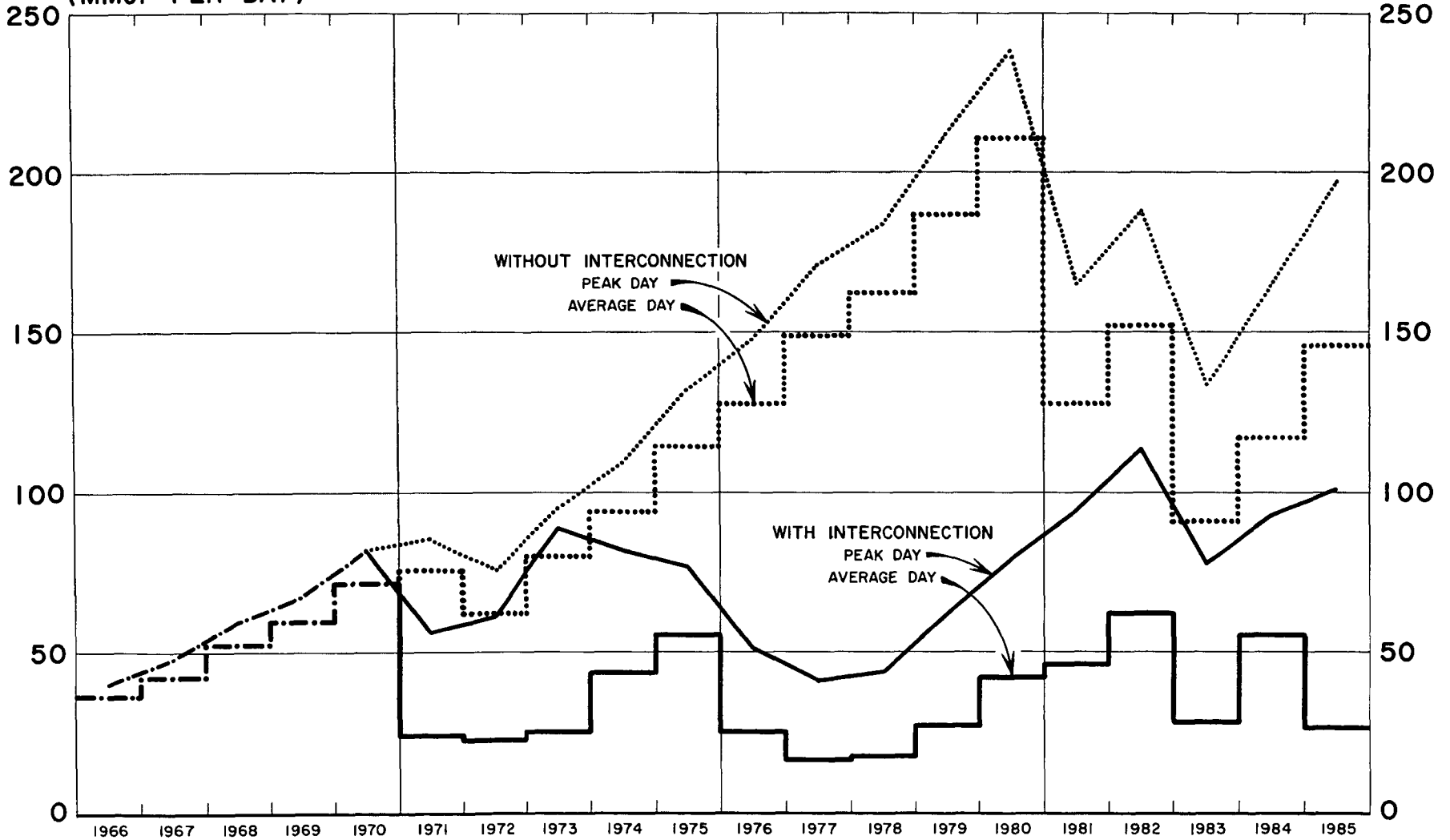

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FIGURE 1

nuclear plant in 1971/72 and completion of interconnection in 1971/72. With interconnection in that year there will be no peaks above about 80-90 MMcf/day before the late 1970's or early 1980's. Thus the Bank Group feels that some expansion of the Sui Gas Transmission Company pipeline to meet KESC's needs may be needed in the years up to 1970/71, but that little further expansion will be required beyond that. Moreover, since KESC's demands will have a much lower annual load factor after interconnection than they do now it may become economical for KESC to buy a larger portion of its fuel in the form of fuel oil and for SGTC to make available to other consumers the pipeline capacity thereby freed. The question of fuel supply for KESC in the next five-ten years is discussed in somewhat greater detail below (paragraphs 7.04-7.18).

VII. THE BANK GROUP'S ADJUSTED POWER PROGRAM

7.01 One of the purposes of long-term planning is to provide a framework for appraising the economics of projects (such as Tarbela) which take a long time to build and are so large relative to the size of the system to which they are added, that it will take some years to realize their full potential benefits. Another, of equal importance, is to examine the implications of such projects for the development of the rest of the system. This latter aspect of long-term planning involves consideration of the steps needed to be taken before and after the completion of a very large project in order to enable the system to assimilate its contribution as efficiently as possible. Two important conclusions regarding system development grow out of the analysis presented in the earlier chapters of this volume: first, Tarbela should be constructed by 1975, and second, if Tarbela is to come on line about that time, then EHV interconnection between the North and the South is warranted in 1971 or as soon thereafter as practicable. The prospect of these two major developments critically affects the type and location of investments in system expansion (e.g. generating equipment, other transmission lines, gas pipeline capacity) that should be made in the meantime; they set the framework of long-term development and the validity of other system developments can only be assessed by reference to them. The purpose of this chapter is, therefore, to bring the results of the analyses of previous chapters to bear in the preparation of a development program for electricity generation and transmission which will enable West Pakistan to draw maximum value from these two very costly investments. The chapter discusses the development of the electric power system over the Perspective Plan period (1965-85); for ease of reference it breaks these twenty years into the four Five Year Plan periods and attempts to consider the major choices that may have to be made for each Plan period. As the time horizon is removed further, projections become less detailed; the action program beyond 1975 aims at showing the possible developments of nuclear energy in West Pakistan, and at indicating tentatively what further hydroelectric investments might be needed after the completion of Tarbela.

Third Five Year Plan Period

7.02 System developments of the remaining years in the Third Plan period are largely predetermined by this time (mid-1967). In recent months, as noted in Chapter II, both the Northern Grid area and Hyderabad have been suffering from severe power shortages, largely as a result of unforeseen mishaps to the Multan units and to the new 15-mw steam unit at Hyderabad, and of unforeseen delays in the completion of the two new steam units at Lyallpur. These shortages should be largely remedied within this year with the repair of the boiler at Hyderabad, the partial repair of the thermal plant at Multan, with the addition to the system of the two new 66-mw steam units at Lyallpur, the completion of Mangla Dam including the first two power units, and the emplacement of a gas turbine purchased as an emergency measure for

Kotri. It appears that almost all the equipment is now available for the construction of the highly desirable 132-kv line to link Hyderabad and Karachi. This line would strengthen the reserves of the two areas and enable Hyderabad to benefit from the cheaper running costs of the larger units presently in existence in Karachi. It should be completed during 1967 or 1968. WAPDA also plans to add two 13-mw gas turbines at Kotri by 1968, as envisaged in the Stone & Webster program, which will be useful for peaking purposes on the combined system. Four 13-mw gas turbines are planned to be added to the Northern Grid system at Lahore during 1968 for peaking purposes, especially in the months when power from Mangla is in short supply. By early 1969 the third unit will be added at Mangla and sometime during the course of that year the planned 125-mw Korangi C station should be added at Karachi. If interconnection with Hyderabad is delayed, Karachi will be short of firm capacity by 1969 without the Korangi C station. Interconnection with Hyderabad will provide some leeway but by the end of 1969 shortages will probably be experienced on the system if the Korangi C station is not completed. An outline of the developments in view during the Third Plan period is given below in Table 66.

Table 66

Development of the Power System During the Third Plan Period (1966-1970)

	Northern Grid	mw	Upper Sind	mw	Lower Sind-Karachi	mw
1966	Existing	467(Oct)	Existing	50(Dec)	Existing	280(Dec)
1967	Lyallpur-Steam	124			Hyderabad-Steam	15
	Mangla 1, 2	90(Mar)			Kotri GT	13
1968	Lahore GTs	52			Kotri GTs	26
1969	Mangla 3	45(Mar)			Korangi C	125

7.03 By 1969, as much as 90 percent of the electric energy required for the Northern Grid area could be supplied from the existing small hydroelectric stations, Warsak units 1-4 and the first three units at Mangla, provided that the system can be run in such a way as to absorb as much of the available hydro energy as possible. As regards the supply of thermal fuel in the North during this period, Sui Northern Gas Pipelines Limited is committed to maintain a regular supply to meet the needs of the Lyallpur and Multan plants. However these plants do also have fuel storage facilities on site, and it may be economical in view of the low load factors in prospect to make more use of fuel oil and to release some of the pipeline capacity for other gas consumers. Whether or not this proves possible, it does not seem that there will be any need for expansion of the pipeline capacity during the next five to ten years to meet the needs of the Multan and Lyallpur stations. The Lahore gas turbines should continue to use gas when pipeline

capacity is available and to use fuel oil at other times.

Fuel Supply in the South, 1965-75

7.04 Some area of choice between fuel oil and natural gas as fuel for thermal generation also exists in the South for coming years. At present KESC draws almost all of its fuel supply from the Sui gas field at a delivered price which averages about 35-36 U.S. cents per million Btu. It is by far the most important gas consumer in Karachi. The main WAPDA plants in the Hyderabad area also draw their chief fuel supplies from the Sui pipeline. Most of KESC's major generating units have the equipment needed for burning fuel oil as well as gas. The new Korangi C station, planned to come on line in 1969, will also have this facility. However, fuel oil presently carries a heavy tax of about PRs 70 per ton which makes it very uncompetitive with natural gas, and KESC has in fact been gradually reducing its consumption of liquid fuels.

7.05 Fuel oil is presently exported from West Pakistan as a surplus by-product of the two refineries in Karachi. It is anticipated that this surplus situation will continue for some years because demand for petroleum products in the Province is sharply peaked in the middle distillates, such as kerosene and high speed diesel oil. The heavier ends of the crude oil imported for production of these products cannot all be absorbed within the country. For instance the older refinery, Pakistan Refinery Limited, produced in fiscal year 1965/66, in addition to lighter products, about 1.1 million long tons of fuel oil, of which about 330,000 tons had to be exported. It was sold at the relatively low cost and freight (c & f) price of about $9.20 per ton (or $1.35 per barrel). The company earned about $3 million from this source in 1965/66, helping to offset the large foreign exchange cost of the imported crude.

7.06 The Pakistan authorities now face the choice of either permitting the expansion of the Sui Gas Transmission Company pipeline needed if all of KESC's fuel demands are to be met from gas or, on the other hand, limiting this expansion and encouraging KESC (presumably by means of a tax rebate on fuel oil) to make greater use of fuel oil. Because the choices involved in the problem of fuel supply in the South concern a time period covering at least two plan periods, the question will be analyzed on a basis of a 10-year period.

7.07 From its computer studies of power system operation the Bank Group has derived projections of natural gas consumption for thermal generation in the Karachi-Lower Sind area. These projections are based on the assumption that all plants that can use gas will do so. Table 67 reproduces the projections for the coming 10 years (more details are given in Annex 9).

Table 67

Projections of Gas Consumption for Generation of Electric Power in Karachi/Hyderabad Area, 1966-76

	Average Day (MMcf)	Peak Day (MMcf)	Annual Load Factor (%)
1966	36	40	90
1967	42	48	88
1968	52	59	88
1969	60	67	90
1970	72	82	88
1971	24	56	43
1972	24	56	43
1973	25	89	28
1974	43	82	52
1975	55	77	71
1976	25	51	49

7.08 These projections may be used to help elucidate this problem of choice between greater reliance on gas or fuel oil, although its final solution must obviously depend on much more precise and up-to-date information than was available at the time of writing this report. The projections of natural gas consumption for the Karachi/Lower Sind area indicate a marked increase in average day and peak day requirements between now and 1970 and then a sharp decline in the early 1970's as a result of the impact of the Karachi Nuclear Plant and EHV interconnection with the North (assuming interconnection in 1971). They would not rise again sharply to reach the peaks attained in 1970 until 1973/74.

7.09 One choice which presents itself is therefore between expanding the gas pipeline in 1969/70 sufficiently to meet all fuel requirements with gas (Case A) or deferring this expansion until 1973/74 and meeting the peaks in the intervening years with surplus fuel oil from the Karachi refineries (Case B). Table 68 gives details of the economic costs of the two alternatives. The items required to expand the capacity of the gas pipeline by about 25 MMcf/peak day in 1969/70 were selected from SGTC's expansion plans and are believed to be representative of true costs. There is a difficulty in estimating the amounts of fuel oil that will actually be required in the absence of adequate pipeline capacity. They have been estimated here on the assumption that total annual gas requirements above the level attained in 1968 would be replaced by fuel oil. This may exaggerate the requirement since the then existing gas pipeline could probably be operated at a higher load factor given the larger fuel requirements of the electrical utilities, and fuel oil could be used simply to meet peaks as they arose during the course of the year. The amounts of Sui gas taken into account in Case A are the thermal equivalents

of the fuel oil considered in Case B. For this analysis Sui gas requirements in 1969 and 1970 are priced at the economic prices of gas in 1969 and 1970 of about 10-12 cents per million Btu, based on the assumption of low total gas reserves. The fuel oil is priced at the current foreign exchange earning price of $9.20/long ton or about 22.5 cents per million Btu (assuming 18,300 Btu/lb).

Table 68

Comparison of Early Expansion of Sui-Karachi Gas Pipeline with Postponed Expansion
(Million US$)

Case A: Early Expansion of Pipeline: All Peaks met with Gas

		Economic Costs		Total Economic Costs	
		Foreign	Domestic	$1=PRs 4.76	$1=PRs 9.52
1969	SGTC: 35.75 miles of 16-inch loop	1.3	1.0		
	KESC: 2.9 bln. cu.ft. of Sui gas		0.3	2.6	3.9
1970	SGTC: 1 x 1100-hp compressor (HQ_3)	0.2	0.2		
	13.75 miles of 16-inch loop	0.5	0.4		
	KESC: 7.3 bln. cu.ft. of Sui gas		0.8	2.1	2.8
1971-73	SGTC: M & O, above facilities p.a.		0.1	0.3	0.3
	Total			5.0	7.0

Case B: Delayed Expansion of Pipeline: Temporary Reliance on Fuel Oil

		Economic Costs		Total Economic Costs	
		Foreign	Domestic	$1=PRs 4.76	$1=PRs 9.52
1969	KESC: 69,500 tons of fuel oil	0.6		0.6	1.2
1970	KESC: 174,000 tons of fuel oil	1.6		1.6	3.2
1971					
1972					
1973	SGTC: 49.50 miles of 16-inch loop	1.8	1.4		
	1 x 1100-hp compressor (HQ_3)	0.2	0.2	3.6	5.6
				5.8	10.0

7.10 The last two columns of Table 68 set out the total economic costs of the alternative programs, the first column indicating the total costs with foreign exchange expenditures valued at the current foreign exchange rate and the last column indicating total costs with foreign exchange expenditures valued at the shadow price of twice the current rate.

7.11 The table shows that in terms of absolute cost (undiscounted) the program with early expansion of the pipeline (Case A) is cheaper than the program with delayed expansion of the pipeline (Case B). However, Case B has the advantage of postponing the relatively substantial investment in pipeline expansion. Application of an 8 percent discount rate makes the two programs approximately equal in present-worth terms when foreign exchange is valued at the current exchange rate but it still leaves Case A (total present-worth costs: $5 million) substantially cheaper than Case B (total present-worth costs: $6.1 million) when foreign exchange is valued at the higher shadow exchange rate. Therefore it may be concluded that, given the assumptions underlying this analysis, the value of foreign exchange earnings from the export of surplus fuel oil, when calculated in terms of an exchange rate reflecting the scarcity value of foreign exchange in the economy, is sufficient to make it preferable to expand the pipeline from Sui early (i.e. in 1969/70) and to meet KESC's major peaks in this period with gas rather than to rely on extensive use of fuel oil.

7.12 The results of this comparison are quite striking because they suggest that even when quite small peaks in fuel requirements are in question the relative economic values of indigenous natural gas and of foreign exchange at the present time and the costs of gas pipeline expansion are such as to make it preferable to meet the peaks with gas rather than with fuel oil. Certainly the peak considered in this analysis is small; the larger the peak considered, assuming roughly the same load factor, the more the analysis would result in a preference for reliance on gas. Two changes in the assumptions underlying the analysis would further strengthen the conclusion in favor of expanding the gas pipeline. Firstly, a slight delay in interconnection between Mari and Karachi beyond 1971 which may be unavoidable due to the difficulty of constructing a complete 380-kv interconnection between Karachi and Lyallpur within the next four years, would increase thermal fuel requirements in the South in the early 1970's and consequently involve much heavier reliance on fuel oil than suggested here if the pipeline were not expanded in the meantime. Secondly, even if it seems to be appropriate after the implementation of interconnection to reduce the amount of gas pipeline capacity committed to serving the electrical utilities because of the low load factor of their demand for gas, as will be discussed below, the approach used above will still apply if the growth of other non-electrical demand for gas is sufficient to take up pipeline capacity relinquished by the utilities. The projection of non-electrical demand for gas in the South given in Appendix Table II of Annex 4 suggests, for example, that the growth of the gas requirements of the proposed Karachi steel

mill and of general industrial consumers in the Karachi/Hyderabad area in the period 1970-72 may be sufficient to take up any gas pipeline capacity which becomes surplus to the needs of the electrical utilities after the completion of interconnection.

7.13 These results derived on the basis of economic prices may differ substantially from those which would result from analysis in terms of financial prices. It was pointed out above that fuel oil, if available to KESC at the current export price of about 22.5 cents per million Btu, would be a cheaper fuel than gas were it not for the rather high tax levied on fuel oil.

7.14 The average financial price to KESC for gas supplies will rise considerably after interconnection is implemented and KESC's fuel requirements are much reduced, because of the slab-pricing structure on gas. However, even with these prices it is doubtful whether the returns to SGTC on the pipeline expansion in 1969/70 would be sufficient after implementation of interconnection in 1971 to make the investment in pipeline expansion at that time appear financially worthwhile. The fact that calculations in financial prices may show different results from calculations in economic prices does not affect the validity of the latter but it does emphasize the problem of the low load factor that may occur on the gas pipeline after interconnection.

7.15 There is a possibility, however, that it may prove possible to meet all gas demands, including peaks, without expanding the whole Karachi-Sui pipeline. This possibility arises because of the proximity of Sari Sing -- a newly discovered gas field some 20 miles from Karachi about which little is yet known. This field may be able to supply part of Karachi's gas requirements for some years, in which case expansion of the line all the way to Sui would clearly become superfluous. It is also possible that Sari may have the right geological features for conversion into a gas storage facility, in which case it could handle peak demands while the main gas supply continued to come from Sui.

7.16 In that case, the gas pipeline from Sui may only have to be expanded sufficiently to meet average day requirements of gas. As far as the gas requirements of the electrical utilities are concerned, this would mean that only about half as much pipeline capacity would be required in any year after completion of electrical interconnection as would be required if all peaks had to be met.

7.17 If it does seem possible to develop Sari Sing for storage purposes and hence to reduce the need for gas pipeline capacity after interconnection, it may also be possible and desirable to meet all of KESC's fuel requirements between 1968 and 1970 with gas as opposed to fuel oil without expanding the Sui-Karachi pipeline. Average day requirements of gas as well as peak day requirements would be increasing in these years but, before Sari is developed for storage purposes, it will likely be necessary to evacuate some of the native gas from the

field. This short-term addition to total supply (assuming that it would be a relatively small amount since Sari is small and much of the gas there would be required as cushion gas if the field were to be used for storage) could play a valuable role in meeting KESC's fuel requirements prior to interconnection.

7.18 The conclusion to be drawn from this discussion appears to be that there is in general much advantage at the present stage of development in West Pakistan in meeting fuel requirements in the South with indigenous natural gas and in providing sufficient pipeline or storage capacity to meet peaks. However, where peaks are very sharp and expected to be very short lived, or where there are temporary uncertainties as to whether the needed facilities are gas-pipeline capacity or storage, it may be worthwhile to meet peak fuel requirements on a short term basis with fuel oil.

Additions to the Power System During the Fourth Plan Period (1970-74)

7.19 WAPDA has tentative plans for this period and has sanctioned the fourth unit at Mangla for completion in 1969. Addition of Mangla 4 alone by 1970 will not be sufficient to provide adequate reserves on the Northern Grid, if planning proceeds on the assumption that Mangla will be drawn down to 1040 feet. It would mean that the Northern Grid would have a total capability of about 869 mw against a projected peak load in the critical month of March of about 813 mw.

7.20 There are a number of alternative ways of supplementing Northern Grid supplies in 1970 which merit consideration. Stone & Webster, who assumed that Mangla would always be operated to a drawdown level of 1075 feet, proposed the postponement of Mangla 4 to 1971 but bringing in Warsak units 5 and 6 in 1970. However this choice seems to have drawbacks. The combination of the Mangla release pattern finally adopted by the irrigation consultant (i.e. drawing down fully by the end of March, rather than retaining some water for release during April) and the monthly pattern of pumping loads projected by him results in the critical period on the power system at this time occurring at the end of March. Warsak units 5 and 6 would add no energy in March and they would add peaking capability only if a reregulating dam were added downstream at the same time to protect the temporary irrigation works built on the Kabul each winter. The real cost of this dam is a matter of considerable uncertainty, and it is likely that the current estimate of $10 million is on the low side. Moreover, the fact that Tarbela releases will, according to the irrigation consultant's final Tarbela release pattern, continue through April, in combination with the monthly pattern of pumping load at that time, will cause the critical period on the power system to shift after completion of the first four to six units at Tarbela from March to May; therefore, that ability to peak at Warsak in March will then become much less valuable. Once the first few units are installed at Tarbela and the critical period has shifted to May, Warsak units 5 and 6 could be added cheaply (about $103 per kw installed) and they would provide

a useful addition to system peaking capability. The re-regulating dam would not be required for the units to be peaked in May since by that time the downstream irrigation bunds are washed away. Several studies involving Warsak were run on the power system simulation model and it was found, for instance, that scheduling Warsak 5 and 6 after completion of the first few units at Tarbela, and Mangla 7 and 8 before installation of the first units at Tarbela, had decided present-worth cost advantages over the approach adopted by the power consultant and by Harza in the past of bringing in Warsak 5 and 6 early and postponing Mangla 7 and 8 until about 1980.

7.21 Without Warsak units 5 and 6, the choice for new capacity in 1970 seems to focus around further units at Mangla and Mari. WAPDA appears to be planning tentatively for completion of Mangla units 5 and 6 in 1970 and/or completion of at least one unit at Mari which would be linked to the Northern Grid by extension of the existing 132-kv line from Rahimyar Khan down a further 50 miles as far as Mari. This line could carry about 120 mw of power. Existence of this line, one 100-mw unit at Mari and the fourth unit at Mangla would be barely sufficient t to meet the combined loads of the Northern Grid and Upper Sind. It would probably be sufficient if the Upper Sind load is less than assumed here, as a result of the Esso fertilizer plant generating its own power supplies. Addition of Mangla units 5 and 6, either with or without the Mari units and the 132-kv Mari-Lyallpur link, would clearly provide sufficient capacity for the North which alone would not be able to absorb very much of their energy in 1970. Thus it appears that the need of the North in 1970 can be adequately met by either the Mari unit and the 132-kv line or Mangla units 5 and 6.

7.22 The program proposed below in fact includes Mangla units 5 and 6 in 1970. In other words, Mangla units 5 and 6 are scheduled in the program a year earlier than might otherwise have been necessary, simply to meet the reserves deficiency in 1970. In practice the relatively large investment required for the Mangla units might be postponed. Even with 380-kv interconnection in prospect for 1971, the 132-kv line would be advantageous because of the role it could play subsequently for purposes of local distribution. Alternatively, the need for Mangla units 5 and 6 might be postponed by drawing down to a minimum reservoir level at Mangla in 1970 above 1040 feet. It was shown in the previous chapter (paras 6.26-6.30) that although there are in general quite strong arguments for drawing down to 1040 feet at Mangla over the period 1967-75, there may be some years when the irrigation benefits of this low drawdown level are more nearly balanced by the power benefits of maintaining the higher drawdown level of 1075 feet. Moreover, the projected patterns of capability at Mangla, given the irrigation consultant's final Mangla release pattern and his projection of tubewell pumping load, are such that planning for a 1075 feet drawdown level and then drawing down to 1040 feet in conditions mentioned above would result in only very limited shortages of capability, which could probably be handled within the scope of reserves available on the system at the time (see Annex 8 for

a general discussion). It may be that 1970 is one year when the savings to be had from planning for a high drawdown level are sufficient to outweigh the risk of a slight shortage due to the year turning out to be one of low flows.

7.23 In considering the timing of construction of Mangla units 5 and 6, it is important to bear in mind the effect that interconnection will have on the absorption of their energy. It was mentioned that the Northern Grid alone would not be able to absorb much of the energy contributed by Mangla 5 and 6 in 1970; an important factor prompting inclusion of the units as early as 1970 or 1971 in the program shown below was the expectation that the first 380-kv link all the way from Lyallpur to Karachi would be in existence by 1971. Comparative studies on the power system simulation model have indicated that, with the 380-kv lines, all but about 900 million kwh of energy from Mangla units 1 to 6 could be absorbed by 1971; without it, unabsorbable hydro energy from these six units would be in the order of 1,700 million kwh. If the Mari-Lyallpur line were to be completed as proposed in 1971, and the Mari-Karachi line only a year later, then it would probably be advantageous to have Mangla 5 and 6 by 1971. Delay in completion of the Mari-Karachi interconnection to 1974 or later would probably mean that it was preferable to postpone Mangla 5 and 6 a year or two, until the Northern Grid had grown sufficiently to absorb more of their energy, and in the meantime to rely on additional capability installed at Mari.

7.24 In any event the Bank Group thinks that the EHV link between Mari and Lyallpur should be built by 1971/72 if this is feasible. This will make it possible to concentrate thermal capacity additions needed in the Fourth Plan period (for firming the hydro plants) in the Mari-Sui area where about 200 mva will be needed for charging the 380-kv line when built. Completion of the 132-kv link between Rahimyar Khan and Mari would make it possible to delay the 380-kv Lyallpur-Mari link one year without involving additions to thermal plant in the North (but assuming the existence of Mangla units 5 and 6). By 1972 the double-circuit 132-kv line would be insufficient to carry to the North the supplies from Mari that would be needed to meet the Northern Grid load in the critical months. An additional circuit might be installed on the 132-kv line, but it is doubtful whether this would be worthwhile when the 380-kv line was anticipated a short time later.

7.25 It appears that the only further addition to generating capability in the North beyond Mangla units 5 and 6 during the Fourth Plan period should be Mangla units 7 and 8 in 1973 or 1974. These units were scheduled by the power consultant in 1981. They would add only about 800 million kwh of energy in a mean year and none in November, December or January. However, they would add (with a 1040 feet drawdown level) 90 mw of firm capability in March-May. Analysis of programs on the power system simulation model indicated that, with a Lyallpur-Karachi intertie in the early 1970's, enough of their energy could be absorbed to make it worthwhile installing them before the Tarbela units came on line. This conclusion might be altered if it

were found that the geographical pattern of loads in the mid-1970's and their likely future pattern were such that substantial savings on transmission investment could be made by temporarily postponing further development at Mangla. If interconnection were not complete by 1973 there is little doubt that the units should be postponed to the later period.

Upper Sind Development, 1970-75

7.26 The low load factor on thermal plant which will be experienced over coming years in all parts of West Pakistan linked by transmission to the Mangla and Tarbela projects was discussed above in relation to fuel supply; it also has an important effect on the type of thermal equipment which is appropriate for installation over the coming years particularly in the Upper Sind area. One of the main advantages of installing thermal equipment in Upper Sind, with an interconnected system, is that such capability can then be made available to the North at times of low hydro capability and to the South at times when that area would otherwise have to rely heavily on local generation fired by Sui gas for meeting base load. Thus, apart from meeting the load of the Upper Sind area itself, Mari plants will be called upon to play a number of other roles. The Bank Group's simulation of the operation of the power system indicates that thermal capability in Upper Sind will, when required in the North, be brought into play on the Northern Grid in the critical months between base load (met by hydro capability) and peak load (met by local thermal generation). To a much greater extent -- in most months of most years -- it will supply power to help meet loads in the South but there too its contribution will generally be utilized between base load met by hydro energy from the North and nuclear energy, on the one hand, and peak load met by local thermal generation on the other. In practice small economies in the fuel efficiencies of thermal plants may be obtained by switching some of the hydro capacity to peaking service at times when sufficient hydro capability and transmission capacity exist; local thermal plant would then be transferred to base load, where a small portion of its total capability will be run continuously. Nevertheless, the Mari units will in general be used for semi-peaking service, base load being carried by nuclear and hydro plants and peak load by local thermal units. In other words, they will be called upon to serve the needs of the South and the North to varying degrees at different times in the year, depending on the amount of transmission line capacity preempted by hydro energy, and generally only for a portion of each day.

7.27 To deal with peaking requirements in the Northern Grid area and Karachi/Hyderabad there are a number of gas turbines already in existence and WAPDA plans to install additional ones in Lahore and Hyderabad. However, the approach to system operation described above implies a need for thermal equipment suitable for low load-factor use in the Upper Sind area also. Stone & Webster handled this problem by recommending that the first 150 mw of thermal plant installed at Mari (coming on line about 1969-71) should be gas turbines and the next

plant following that should be an extended rating steam turbine. The extended rating unit has a lower construction cost than a regular steam unit per kw of maximum capacity. When utilized at or below its base rating it has the same fuel efficiency as a regular steam unit, but when use is made of its maximum capacity its fuel efficiency is lower. Stone & Webster estimate the economic costs per kw installed as follows: gas turbines $105, 150-mw extended rating turbine $134, and 150-mw regular steam unit $145. Stone & Webster's proposals apparently diverge from WAPDA's present plans, which foresee two 100-mw steam units at Mari in 1970/71 and a further 200-mw steam unit at Mari about 1972/73.

7.28 The question of what types of thermal equipment to install at Mari is complex; it depends greatly on the load factors that the plant is likely to experience in later years. As pointed out the saving in capital cost on the gas turbines is gained at the expense of heavier fuel consumption when the plant is in operation; equally the extra capability of the extended rating units is secured at a low cost per kw installed but at the expense of high fuel consumption when the unit is run beyond its base rating. The gas turbines, for instance, would have a gross heat rate (per kwh sent out) of about 18,000 Btu compared with the regular steam units' gross heat rate (per kwh sent out) of about 12,000 Btu. In order to compare the merits of gas turbines and regular steam units for installation in the Upper Sind in the early 1970's, two power programs were prepared, identical to one another except for the fact that one included a 200-mw regular steam unit at Mari in 1974 and the other included 200 mw of peaking gas turbines in the same year. Both programs were run through the power system simulation model. The present-worth costs of the two programs showed a marked advantage to the one with the gas turbines: a saving in present-worth terms of the order of $2-3 million when Mari fuel was priced at 14 cents/mln Btu and foreign exchange expenditures were valued at the current exchange rate. At the higher foreign exchange rate the saving in present-worth terms was about $6 million. The difference in capital cost of the two plants (undiscounted) in 1971-74 is about $10 million. The higher the price set on Mari fuel the less attractive the gas turbines would appear, other things being equal. Rough calculations on the basis of the power development programs analyzed on the simulation model suggest that the fuel price would have to rise to about 24 cents/mln Btu to eliminate the savings calculated on the basis of the current foreign exchange rate and to about 32 cents/mln Btu to eliminate the savings calculated on the basis of the higher exchange rate. These are all uniform fuel prices over the full length of the planning period. Inspection of the economic fuel price series (see detailed discussion in Annex 5) suggests that during most of the planning period the economic value of fuel will be substantially below these prices. In later years, the economic values of fuel rise above these levels. However by that time the equipment will be used to a lesser extent as a result of the addition of other more modern generating facilities; moreover in a present-worth calculation the discount rate will have a heavier effect on costs incurred in these later years.

7.29 Further study will be needed to determine exactly what proportion of generating equipment installed during the Fourth Plan period should be gas turbines, but it appears clear that some of the capability installed at Mari should be in this form. Loads fluctuate heavily in most electric power systems over the days, weeks and months, but in West Pakistan the capability of the main sources of generation will also vary greatly over the seasons, so that low load factor use of thermal equipment will be quite a long-standing problem. Alternative solutions to the problem, as regards the type of generating equipment installed, should be investigated. There are other types of equipment besides extended rating units and gas turbines that may be appropriate. There may well be advantage in making one or both of the 100-mw units which WAPDA plans for installation at Mari in the early 1970's extended rating units. Even with these as extended rating units it would still appear advisable to have some gas turbines in addition. The program presented below includes a relatively large amount of gas turbines -- 200 mw -- at Mari in the Fourth Plan Period as an indication of the order of magnitude of peaking capability that seems, from the perspective of the present, worthwhile installing given the hydro, steam and nuclear capability planned.

Development of the Southern System, 1970-74

7.30 The chief factors affecting the development of the Karachi/Hyderabad power system in the Fourth Plan period will be the date of interconnection with the North and the date when the Karachi nuclear plant becomes available as reliable capacity. Regarding the nuclear plant, the same assumption is made here as in Stone & Webster's report -- that 25 mw of its capability will become available as reliable capacity for KESC in 1971 and the remaining 100 mw in the following year. The agreement between KESC and the Atomic Energy Commission apparently provides that nuclear energy would be made available to KESC at a rate of about 3.5 paisa (7.3 US mills) per kwh. This is slightly higher than the direct operating costs of most of KESC's plant per kwh produced (i.e. excluding fixed charges); average direct costs of generation (i.e. fuel plus Operation and Maintenance) on the KESC system fell from about 9 mills per kwh sent out in 1960/61 to about 6.2 mills per kwh sent out in 1964. Therefore from a financial point of view, it might be preferable for KESC to use relatively small amounts of nuclear energy and use its own equipment more intensively. However, from a national economic point of view it would probably be desirable to operate the nuclear plant, once installed, at as high a load factor as possible. The plant is very expensive in capital cost, but it should be relatively cheap in fuel cost, even when account is taken of the heavy foreign exchange component in the fuel. The Bank Group has therefore generally assumed in its studies that the nuclear plant would be dispatched with an 80 percent load factor, except when its energy is partly displaced from base load by hydro energy from the North.

7.31 After completion of the Korangi C unit in 1969 the Karachi/Hyderabad power system would have a total capability of about 460 mw.

For 1970 the program shown in the following table includes 26 mw of gas turbines at Hyderabad -- partly in order to provide reserves in that year sufficient on the largest-single-unit-out criterion and partly because of the role that gas turbines will be able to play after interconnection in providing area protection and reducing the need for spinning reserve. Addition of the first 25 mw of the nuclear plant by the time of annual peak load in the autumn of 1971 would provide a total capability of 510 mw against a predicted peak load of about 442 mw. If the Southern system is interconnected with the North in 1971, then this would mean that there is sufficient firm capability available to meet the 1971 peak. If the EHV line is not extended as far as Karachi by 1971 then this capability of 510 mw would cover projected demand with a reserve margin adequate on a reserve criterion of 12 percent of installed thermal capability but inadequate on a single-largest-unit-out reserve criterion (i.e. Korangi C station, 125 mw). Therefore without interconnection by 1971, it would be necessary to install additional thermal capability to ensure full security of supply in that year. If interconnection is completed by 1971 -- or by 1973, if the nuclear capability becomes firm a little earlier than anticipated here -- then no addition to the thermal plant in Karachi/Hyderabad would be necessary during the Fourth Plan period. However once Karachi/Hyderabad begins to draw upon Mari for firm capacity, prudence requires that a second transmission line be available, and this is included in 1974 in the program given below.

7.32 A summary of the proposed power program is given in Table 69 which shows a tentative program for the development of generation and 380 kv transmission during the Fourth Plan period.

Table 69

Proposed Development of the Power System in the Fourth Plan Period (1970-1974)

	Northern Grid	mw	Upper Sind	mw	Lower Sind-Karachi	mw
1969	Existing	788 (Mar)	Existing	50 (Oct)	Existing	459 (Oct)
1970	Mangle 4	45 (Mar)	Mari-Steam	100	Hyderabad GTs	26
	Mangla 5, 6	90 (Mar)				
1971	Retire	(15)	Mari-Steam	100	Karachi-Nuclear	25
1972					Karachi-Nuclear	100
1973	Mangla 7, 8	90 (Mar)			Retire	(15)
1974			Mari GTs	200		

380 kv Transmission: 1971: Lyallpur-Mari-Karachi (s/c)
1974: Mari-Karachi (s/c)

Power System Development in the Fifth Plan Period (1975-79)

7.33 Three main sets of decisions that will arise for the Fifth Plan period can be identified: the scheduling of the units at Tarbela, the steps that should be taken to expand the EHV transmission system and the type and location of thermal capability to be provided to firm up the hydroelectric units and help stabilize the transmission system.

7.34 How rapidly the units should be brought in at Tarbela will depend on details of the load growth that cannot be foreseen with sufficient accuracy at the present time to make a firm judgment; indeed, given the fact that the Tarbela Project can be justified on the basis of demands for electric power and for irrigation of the general order of magnitude presently foreseeable, one additional advantage of the project is the flexibility that it will provide for introducing units more or less rapidly according to the way the power load actually grows. Stone & Webster tentatively proposed the scheduling of the first eight units at Tarbela relatively quickly, two per year, in the years following completion of the dam in 1975, and the last four units for installation somewhat later in 1982/83. A recent Harza proposal schedules the first two units in 1974/75, one unit in each of the years 1975-77, two units in each of the years 1978-80 and the twelfth unit in 1981. Stone & Webster assumed a drawdown level of 1332 feet and Harza 1300 feet. The comparison of drawdown levels made above (para 6.28) suggested that in general there appear to be substantial advantages to maintaining the higher drawdown level, at least through the period 1975-85. Various different schedulings of the Tarbela units were tested on the power system simulation model as discussed in more detail in Annex 7 and these studies suggested that, with this drawdown level and with the main load forecast underlying them, the best schedule might be to bring in the first four units in 1975 and 1976 and to postpone the remaining eight for introduction, two per year in 1978 and 1979 and the last four in 1980, when the capacity of the interconnected system to absorb additional supplies of energy will have grown. The inexpensive units at Warsak could be added in 1977-79 to provide useful peaking capability once the critical period has become May. If the load in the North turns out to be higher than implied by the main load forecast used by the Bank Group, then it may become attractive to bring in the Tarbela units somewhat more rapidly.

7.35 There is some question as to the feasibility of bringing in the first two units at Tarbela by early 1975. At the time when Stone & Webster were reporting, these units were expected in service during the fourth quarter of 1974. Apparently the latest TAMS construction schedule for Tarbela indicates that units 1 and 2 could not be completed before June 1, 1975; this would mean that they would come on line after the critical period of that year had passed. It would be desirable, if still possible, to bring in Tarbela units 1 and 2 before the spring of 1975. If not possible, then the proposed program would indicate a severe shortage of reserves in 1975. With 400 mw at Mari, a 125-mw Korangi unit 4 in Karachi and all eight units at Mangla,

net system capability in the critical period at the end of March in 1975 would be 2,167 mw, against an anticipated peak load of 2,093 mw. A reserve-criterion of 12 percent of thermal capability and 5 percent of hydro capability would imply the need for about 220 mw of reserves at this time. One solution to this shortage of reserves would be to draw down the Mangla Reservoir to only 1075 feet in the spring of 1975. This would provide additional capability through the critical period of about 140 mw, just sufficient to provide adequate reserves. If 1974/75 proved to be a year of low rabi flows so that full drawdown at Mangla became essential to meet irrigation requirements, then a relatively small amount of load shedding would be necessary -- and none, if all other equipment on the system was operating to full capability (see para 6.30). The only alternative to keeping up Mangla Reservoir in 1975 in order to provide sufficient firm capability would be to add thermal capacity. Such additional thermal capacity would probably best be installed at Mari. The program which was prepared to meet the higher load forecast for the Northern Grid area does include a 150-mw unit at Mari in 1974 in addition to the 400 mw included in the program proposed here. If the development on the basis of Mari gas itself is indeed limited to 400 mw, then this unit would have to be fired by Sui gas; but it would probably be advantageous to locate it along with the Mari-fired units at Gudu, as discussed in para 6.35. The special disadvantage which would attach to bringing in additional thermal capacity in the spring of 1975 to compensate for a delay in Tarbela is that this would mean installing the thermal units two or three years before they would otherwise be needed. This is the reason why the benefits to power of maintaining a higher drawdown level at Mangla in 1975, if the first Tarbela units are delayed, would be particularly large.

7.36 Expansion of the 380-kv transmission system in the Fifth Plan period will consist mainly in the construction of lines from Tarbela to Lyallpur and the addition of further links between Lyallpur and Mari to enable transfer of hydropower to the South. The first Tarbela-Lyallpur line would be required along with the first units at Tarbela in 1975, and additional 380-kv lines should accompany each block of four units added at Tarbela. These lines will not have sufficient capacity to carry the full potential output of Tarbela in the summer flood months but nor could the Northern Grid absorb the full potential of Tarbela in these months within the 20-year plan period studied, according to the load forecasts underlying these studies. Hence it would be necessary to increase transmission line capacity all the way to Karachi in order to find a use for the full output of Tarbela in the summer. Investment of the magnitude required for this purpose could hardly be justified in view of the fact that the extra transmission capacity would be used for only a few months in each year. As loads grow in the northern part of the Punjab, it will probably be possible to absorb the extra power available from Tarbela in the flood months without installation of expensive long-distance transmission. As regards the transmission lines between Lyallpur and Mari studies with the aid of the power system simulation model suggested that they

might usefully be brought in a year or two earlier than Stone & Webster had suggested. In the program for the Fifth Plan period given below the second Lyallpur-Mari link is scheduled in 1976 and the third link in 1979. The justification for bringing the lines in earlier is largely in terms of the fuel savings that would result from making larger quantities of hydro energy available in the South. These are, of course, only tentative judgments as to how things appear from the present perspective. Precise scheduling, closer to the time of construction, will depend upon many factors, particularly the overall fuel situation as it then appears, the speed with which hydroelectric development has proceeded, and the extent to which thermal capacity additions are concentrated in the Upper Sind.

7.37 It will be essential in the late 1970's to provide additional thermal capability. According to the main load forecast underlying these studies, there will be a need for an additional 400 mw of thermal capability in this period (besides the 125-mw Korangi unit 4) even if all twelve units at Tarbela are installed between 1975 and 1980, as proposed. With the higher load forecast the need would be of the order of 600 mw. Additional thermal capacity will be required for two main purposes: first, to add capability that will be run with a low load factor to provide megawatts when the reservoirs are fully drawn down and, second, to provide capability at both ends of the EHV transmission line to help stabilize it. It was partly with this latter point in mind that Stone & Webster, in contrast to Harza, suggested substantial thermal development in Karachi as well as at Mari through the years 1975-85.

Use of Lakhra Coal for Thermal Generation

7.38 As far as can now be foreseen, it appears that the main contenders for thermal generation in this period would be coal-fired plants and gas-fired plants. Nuclear capability would probably not be appropriate until the early 1980's, because even in the Karachi area, it would have a load factor of only about 50 percent in 1975 as a result of hydro energy and supplies from the Atomic Energy Commission nuclear plant preempting base load in most months. Since most of the fuel cost on nuclear equipment occurs in the form of fixed charges on the cores, there is a heavy penalty to low load factor operation.

7.39 The chief possibility for generation on the basis of coal in this period would appear to be a mine-mouth plant at the Lakhra coal field. The coal at Lakhra is of very low quality -- it is really lignite -- but the reserves are extensive and the field is the largest in West Pakistan in terms of calorific value of fuel deposits; it is in a more accessible location than most of the other coal fields of the Province being situated about 80 miles north of Karachi. It is not known whether water is available in adequate quantities to support a large thermal plant at Lakhra, but assuming that it is, then the estimate of capital cost of a coal-fired plant (including ash-disposal facilities, etc.) which is about $190 per kw installed would apply. This cost is based on the advice of the power consultant; it is about 35 percent greater than the figure for a gas-fired plant of comparable

size. The annual maintenance cost of a coal-burning plant would also be higher totalling about $3.25/kw installed as compared with $2.00/kw installed for a gas-fired plant.

7.40 With these high fixed costs for coal-fired thermal generation, coal will have to be available a good deal cheaper than gas in order to be competitive with it. The price of Lakhra coal is actually a matter of great uncertainty. A letter from the Directorate of Mineral Development to WAPDA cites a possible pit-head price of about PRs 35 per ton or 44 cents per million Btu. However, the Third Five Year Plan document implies that at least some of the Lakhra coal is nearer to the surface and subject to recovery by strip mining. In this case, the price might be more in the neighborhood of PRs 20-25 per ton.

7.41 Figure 2 shows the results of a comparison between a 200-mw gas-fired plant and a 200-mw coal-fired plant. It is based on two assumptions that are favorable to coal: first, that the plants, each of which would have a 30-year life, would be able to obtain a load factor during the first 10 years of their life as high as 80 percent[1/] (which, as pointed out above, is not likely as early as 1980 in view of the continued dominance of the power system by Tarbela at this period); second, that there would be no additional costs involved in linking a coal-fired plant, as opposed to a gas-fired plant, to the EHV transmission system. The Lakhra coal field, lying between Karachi and Hyderabad, is in fact reasonably close to the path that would be traversed by the 380-kv link between Karachi and Hyderabad, but there would likely be more costs involved in linking such a plant with the line than in linking a plant at, say, Gudu with the line. Given these assumptions, figure 2 indicates the combinations of gas prices and coal prices at which it would be preferable to install gas-fired plant and those at which it would be preferable to install coal-fired plant.

7.42 The figure suggests that coal at PRs 20 per ton (25 cents per million Btu) would break even with gas available at about 34 cents per million Btu, while coal at PRs 35 per ton would break even with gas at about 54 cents per million Btu. The Bank Group's projections of economic values of natural gas indicate an economic value of gas in 1980 in the neighborhood of 29 cents per million Btu if reserves are as currently estimated and about 15 cents per million Btu if reserves turn out to be somewhat larger. The economic values would rise quite rapidly in the following years to about 45 cents and 25 cents respectively, for the two assumptions regarding reserves, in 1985. Since these economic prices for gas rise over time, as estimated reserves are assumed to be gradually exhausted, they are not directly comparable with the break-even prices calculated above. It would be wrong to infer, for instance, that a plant based on

1/ Load factor in second 10 years of life was assumed to be 60 percent and in third 10 years, 40 percent, declining as the plants became more out-of-date relative to other plants added to the system in the interim.

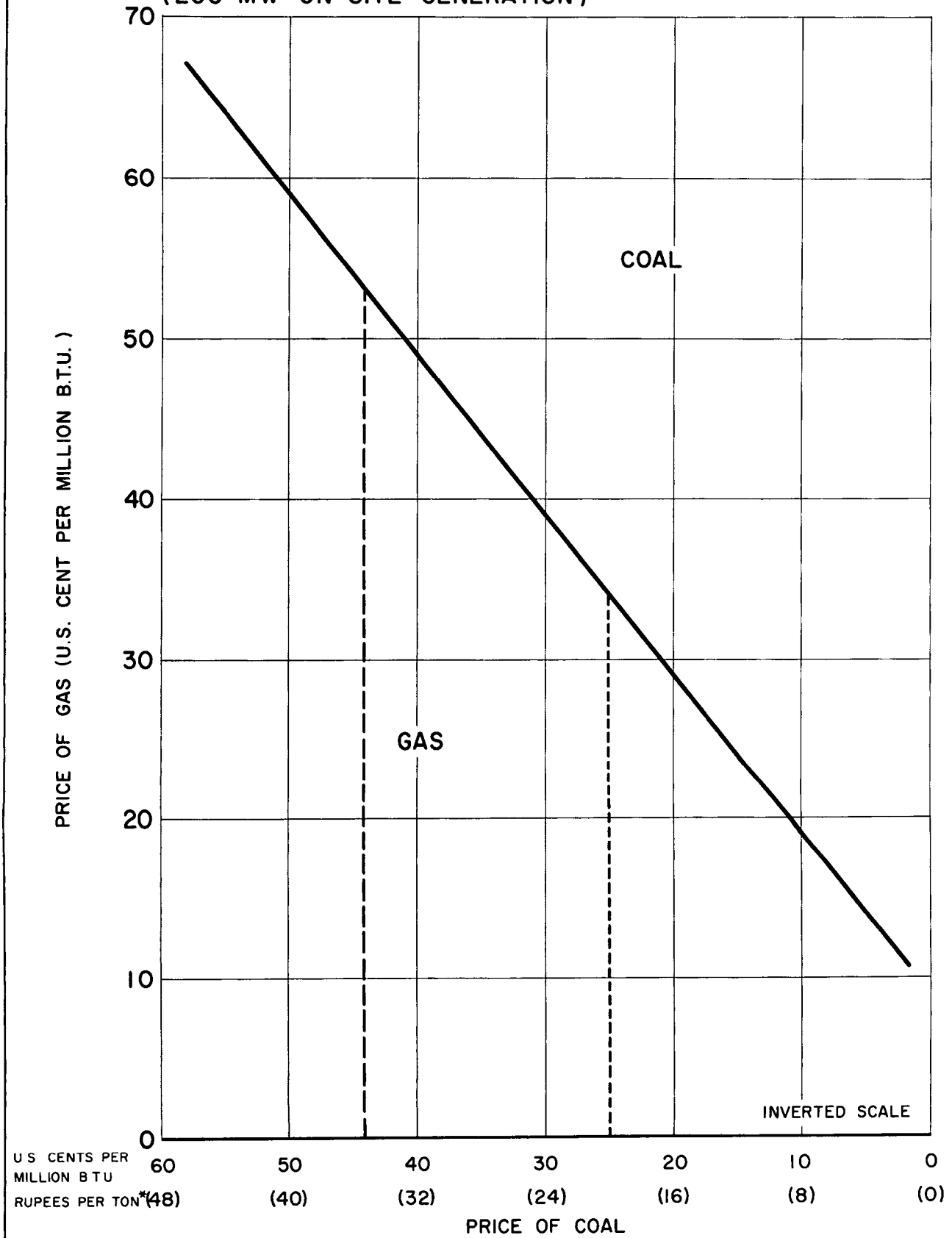
strip-mined coal would become competitive only when the economic value of gas rose to 34 cents per million Btu, for most of the life of the coal-fired plant would be spent when the economic value of gas is, according to these projections, substantially higher. Nevertheless, the fact that during the early years of the life of a coal-fired plant built in the late 1970's (i.e. at the time when it would be run with a higher load factor than it would attain later in its life) the economic price of gas would be considerably below the break-even point does suggest that a coal-fired plant would not be competitive with a gas-fired plant at this time. In the early 1980's, on the other hand, the economic value of gas as estimated on the basis of currently known reserves would soon rise above 34 cents per million Btu and a coal-fired plant might become attractive at that time. Discovery of additional gas reserves would, on the other hand, keep the scarcity price of gas down as implied by the price-series developed on the assumption of larger reserves and then it is unlikely that coal-fired generation would become attractive until later.

7.43 Thus it appears that the best source of thermal generation in the late 1970's would be natural gas. Whether plants constructed at this time might better use Mari gas or Sui gas will depend greatly on the reserves that finally turn out to exist at Mari. If Mari reserves prove no greater than currently estimated (1.8 trillion cubic feet) it may be necessary to base thermal plants installed in this period on Sui gas though not necessarily so, given the relatively low load factor that will occur over the next ten to twenty years on thermal plant at Mari and the consequent low usage of fuel. Whether the plant was fired by Sui gas or Mari gas, it would likely be advantageous to locate quite a high proportion of the additional capability required at this time in the Upper Sind area, as argued in paragraph 6.35. At the same time some of the thermal capacity added in this period should probably be located in Karachi to protect the stability of the system and to leave a relatively large proportion of the transmission capacity free for sending hydropower South in this early period when Tarbela would be generating much more energy than could be absorbed in the North. Table 70 on the following page represents a picture of the system additions that are tentatively proposed for the Fifth Plan period.

Proposed Power System Development in the Sixth Plan Period (1980-85)

7.44 By the early 1980's, according to the Bank Group's adjusted program the potential at Tarbela will have been largely utilized: 12 units will have been installed and, with interconnection, most of the energy available from them will have been absorbed except in the flood months July-September. Substantial additions to generating capacity of the order of 700 mw in the North and 1000 mw in the South will be needed. The power consultant met this need in his proposed program with the last units at Mangla and Tarbela, about 600 mw at Mari, based on Mari gas, and 900 mw at Karachi, tentatively based on Sui gas. Harza programming foresees extensive development at Mari in these years.

THERMAL GENERATION IN LATE 1970'S
LAKHRA COAL vs. MARI/SUI GAS
(200 MW ON-SITE GENERATION)



*Assuming about 7,500 B T U's/lb of coal

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Table 70

Proposed Development of the Power System in the Fifth Plan Period (1975-1979)

	Northern Grid	mw	Upper Sind	mw	Lower Sind-Karachi	mw
1974	Existing	998(Mar)	Existing	450(Mar)	Existing	595(Mar)
1975	Tarbela 1, 2	180(Mar)			Korangi 4	125
1976	Tarbela 3, 4	180(Mar)				
1977			Mari/Sui 5	200		
1978	Critical changes to May					
	Tarbela 5, 6	146(May)				
	Warsak 5, 6	80(May)				
1979	Tarbela 7, 8	146(May)			Korangi 5	200

380 kv transmission: 1975: Tarbela-Lyallpur (s/c)
1976: Lyallpur-Mari (s/c)
1978: Tarbela-Lyallpur (s/c)
1979: Lyallpur-Mari (s/c)

7.45 As far as can now be foreseen, the critical factor in deciding the best source of thermal generation in this period will be the situation, as it then appears, regarding natural gas reserves. According to the Bank Group's projections the main gas reserves, as currently known, would be exhausted within about 15-20 years beyond 1980. An additional three trillion cubic feet at Mari, or its equivalent in thermal value at Sui, would extend the life of the reserves about five more years. In the Bank's approach to the economic pricing of gas these trends express themselves in sharply higher gas prices in the early 1980's than in the preceding periods -- about 30-40 cents per million Btu at well-head as compared, for instance, with 10-15 cents in the early 1970's.

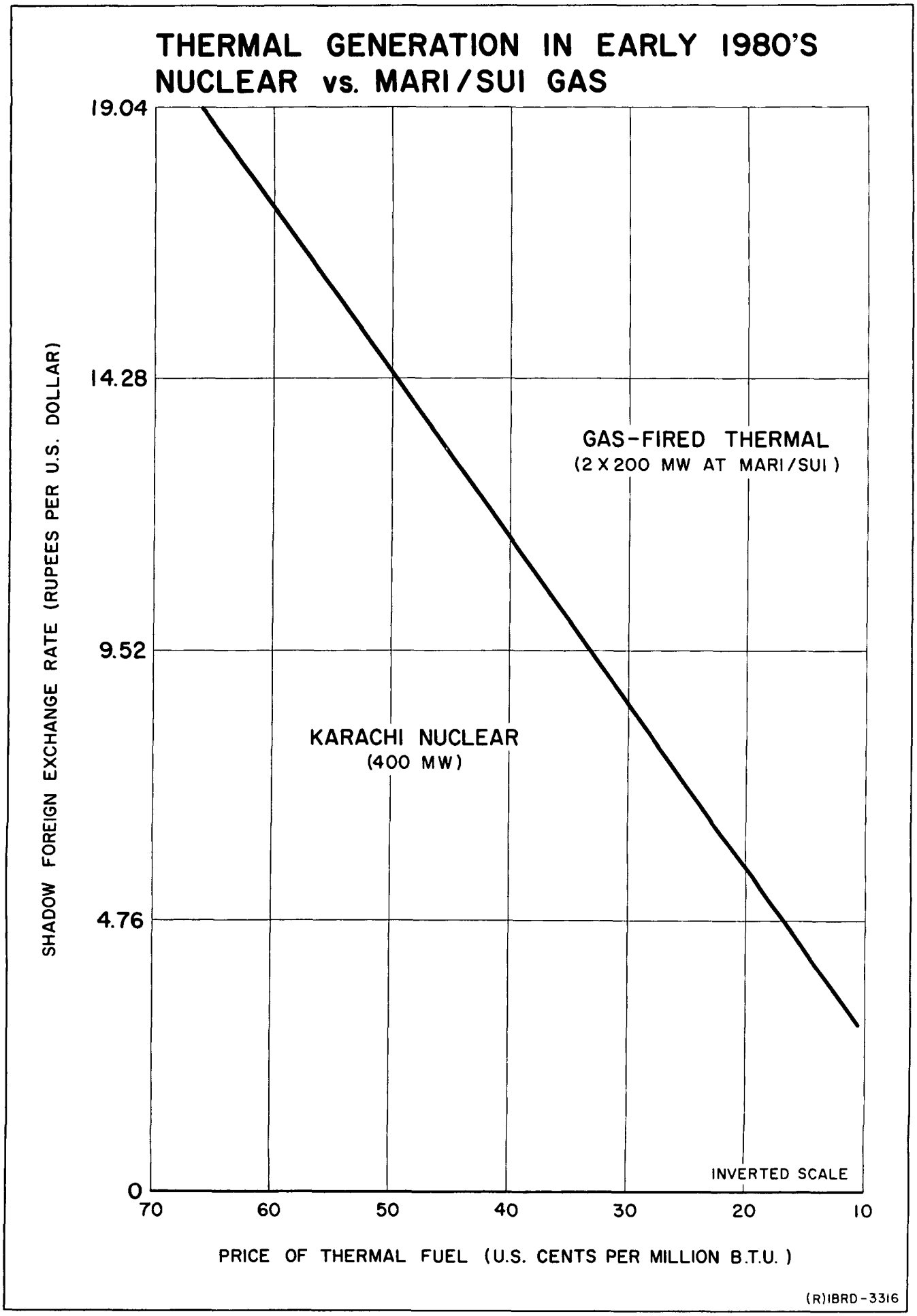
7.46 To the extent that gas reserves are depleted and unavailable for commitment to power generation, most thermal fuel will probably have to be imported, and it is partly for this reason that the second critical factor affecting choice among alternatives in this period will be the Province's overall foreign exchange situation. As far as can be foreseen at this point in time there will be no alleviation of the foreign exchange stringency during the Perspective Plan period; and tentative projections for the energy sector suggest that fuel imports may be becoming an increasing part of total imports in this period. Whereas decisions for the near future may be discussed in terms of the current scarcity value of foreign exchange (estimated at about $1 = PRs 9.5), the exchange rate appropriate for consideration of later developments may be considerably higher than this.

Nuclear Generation

7.47 Despite the foreign exchange difficulties that may occur, it appears that there is quite a strong case for going over to extensive development of nuclear power in the South in the early 1980's. In the North the load factor on nuclear plant would still be far too low (about 20-30 percent) to make nuclear plant a serious contender for this period, as far as can now be foreseen. Moreover it is doubtful whether the Pakistan Western Railway would be able to carry the components of the larger and more economic nuclear units to the North by then. But in the South loads should be adequate by the early 1980's to give a 400-mw nuclear unit a load factor of better than 80 percent; and by 1985 a second 400-mw nuclear unit could have a load factor, even after absorption of large quantities of hydro energy, of nearly 70 percent. Moreover, by the early 1980's loads on an interconnected system would be growing rapidly enough to absorb reasonably quickly nuclear units of about 400 mw capability; on present technology this appears to be the minimum size at which the economies of nuclear generation are gained. By the early 1980's, the world nuclear industry and the industrial base in West Pakistan should also have developed far enough to make it possible to construct, at least in the Karachi area, nuclear units of the 400 mw size. Before that time it is doubtful whether the heavy welding that is involved with nuclear plants as currently designed could be performed with locally available equipment and whether the specialized components of a nuclear unit could be made available cheaply.

7.48 Figure 3 presents the results of a comparison made between a 400-mw nuclear unit at Karachi and two 200-mw gas-fired units at Mari/Sui in the early 1980's. The comparison was based on current estimates of capital cost of plant (about $170/kw installed for the 400-mw nuclear unit and $140/kw installed for a 200-mw gas-fired unit). It was also based on the assumption (which may be generous to gas, given the relatively greater flexibility of nuclear equipment as regards location) that no special transmission costs would be involved to bring the power from the plant to the market. It was assumed in effect that increasing amounts of the then existing 380-kv transmission capacity from Mari to Karachi would be becoming available for sending power generated at Mari/Sui to Karachi as a result of the increasing absorption of Tarbela power in the Northern Grid. Thirty-year lives were assumed for both types of generator, with a permanent 80 percent load factor on the nuclear plant and load factors of 80 percent on the gas-fired plant in the first 10 years of its life, 60 percent in the second 10 years and 40 percent in the last 10 years.

7.49 The comparison in Figure 3 suggests that, at the current scarcity value of foreign exchange (i.e. $1= PRs 9.5), nuclear generation would be competitive with gas generation at a gas price of about 33 cents per million Btu. At a higher foreign exchange rate, for instance, treble the current rate (i.e. $1= PRs 14.3), nuclear generation would be competitive with gas at a price of about 50 cents per million Btu. The actual break-even prices may in fact turn out


THERMAL GENERATION IN EARLY 1980'S
NUCLEAR vs. MARI/SUI GAS
19.04
14.28
9.52
4.76
0
SHADOW FOREIGN EXCHANGE RATE (RUPEES PER U.S. DOLLAR)
GAS-FIRED THERMAL
(2 X 200 MW AT MARI/SUI)
KARACHI NUCLEAR
(400 MW)
INVERTED SCALE
70
60
50
40
30
20
10
PRICE OF THERMAL FUEL (U.S. CENTS PER MILLION B.T.U.)
(R)IBRD-3316

to be significantly lower by the time that large-scale nuclear plants become relevant for power development in West Pakistan because nuclear technology is developing so rapidly. An indication of the rapidity of technological development is given by the fact that Stone & Webster have recently reduced their best estimate of the capital cost of a 400-mw nuclear plant from the figure of $170/kw installed at Karachi (taken from their report published in May 1966) to about $150/kw installed at Karachi. There appears to be a strong presumption therefore that, as far as can now be foreseen, most of the thermal development in Karachi from the early 1980's on might be nuclear.

7.50 These considerations, together with the technical factors mentioned above, led the Bank Group to include two 400-mw nuclear units in its proposed program for the South in the early 1980's.

Kunhar in the Early 1980's

7.51 The North will present an entirely different problem from the South in the Sixth Plan period because at this time it will still be so heavily dominated by Mangla and Tarbela with their seasonal fluctuations in power output. The main alternative to a continuation of development on the basis of gas for serving the Northern Grid in this period would appear to be Kunhar. This project was discussed in Chapter VI as an alternative to Tarbela; in the 1980's it would come in as a sequel to Tarbela. For study of Kunhar in the early 1980's, two 20-year power development programs were prepared, identical except for the fact that one program brought in the various units of the Kunhar Project in the early 1980's while the other envisaged a continuation of thermal development through this period. Figure 4 is a display of the present worth of the costs of the two programs at different fuel prices and different foreign exchange rates. It suggests that Kunhar as a sequel to Tarbela in the early 1980's is less attractive than it appeared as an alternative to Tarbela in the mid-1970's. The continuous line under Kunhar in Figure 4 represents the present worth of the actual costs of the program including Kunhar, with fuel valued at different prices. The dashed line immediately beneath represents these same costs reduced by the present worth of the value of the potential irrigation benefits from Kunhar storage and the addition to Mangla capacity and energy made by construction of Kunhar upstream. The figure shows that the break-even points for Kunhar following Tarbela are a fuel price of about 58 cents per million Btu when foreign exchange costs are valued at the current exchange rate and about 90 cents per million Btu when foreign exchange costs are valued at the higher shadow exchange rate; this assumes that the special side benefits of Kunhar are indeed of the magnitude attributed to them. The break-even fuel price for 'Kunhar after Tarbela' is substantially above the break-even fuel price for 'Kunhar in place of Tarbela': 58 cents against less than 40 cents at the current foreign exchange rate and 90 cents against a little over 50 cents at the higher foreign exchange rate. The main reason for this is that by the early 1980's, Tarbela will, especially in July-September, be

producing more energy than can be absorbed even in a system with interconnection. As a result the useful energy contribution of Kunhar at this time would be smaller than it would be if Tarbela were not in existence. As the years pass and the load grows, so that Kunhar energy could be more fully absorbed immediately after the project was completed, the break-even prices given above for Kunhar in the 1980's would fall.

7.52 The Bank Group's projections of the economic value of natural gas (Annex 5) suggest that, even if no more gas is discovered in the meantime, it would not rise above 90 cents per million Btu before 1990. Therefore it appears that as far as can now be foreseen, additions to generating capacity to meet the growth of the Northern Grid and Upper Sind loads in the 1980-85 period would best be based on Mari/Sui gas. Kunhar or hydroelectric development in connection with a further surface water storage project might become appropriate in the late 1980's.

7.53 The Bank Group gave attention to another possible hydroelectric development that might be brought in within the Perspective Plan period after the completion of 12 units at Tarbela -- namely raising Mangla for power purposes -- and it was found that, as far as could be foreseen, this solution would be attractive only after 1985. One of the main considerations working against it was the fact that a sizable portion of the energy and capability which it would add would occur in the summer flood months when Tarbela would, at this time, still be producing more energy than could be absorbed.

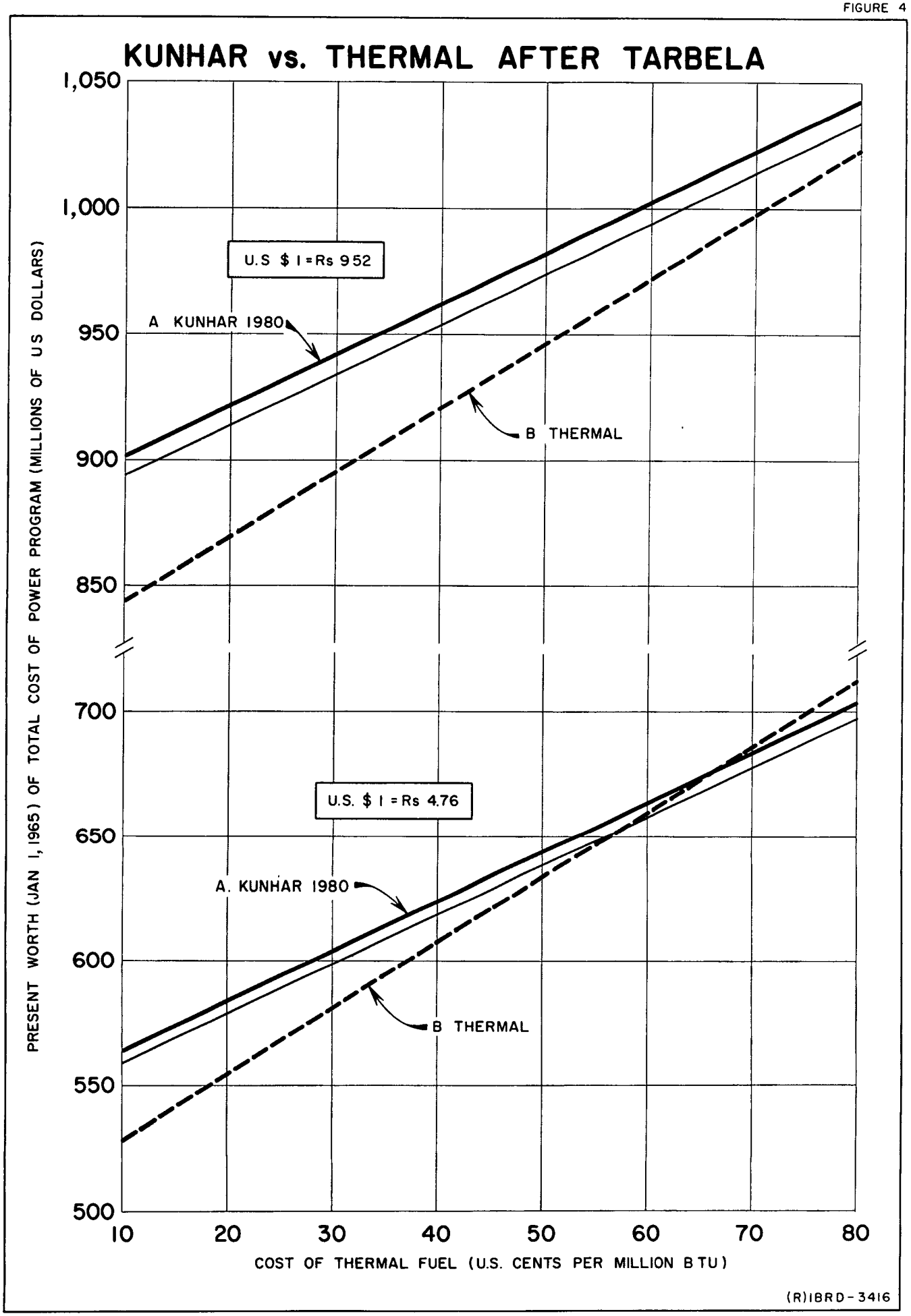
7.54 Table 71 gives a schematic presentation of the main steps in system development in the Sixth Plan period that these various considerations seem to suggest.

Table 71

Proposed Development of the Power System in the Sixth Plan Period (1980-85)

	Northern Grid	mw	Upper Sind	mw	Lower Sind-Karachi	mw
1979	Existing	1732(May))	Existing	650(May)	Existing	920(May)
1980	Tarbela 9, 10	146(May)				
	Tarbela 11, 12	146(May)				
1981					Korangi 6	300
1982			Mari/Sui 5a	200		
			Mari/Sui 5b	200		
1983					Karachi-Nuclear	400
1984			Mari/Sui 6	300		
1985					Karachi-Nuclear	400

380 kv transmission: 1980: Tarbela-Lyallpur (s/c)


KUNHAR vs. THERMAL AFTER TARBELA
PRESENT WORTH (JAN 1, 1965) OF TOTAL COST OF POWER PROGRAM (MILLIONS OF US DOLLARS)
1,050
1,000
950
900
850
700
650
600
550
500
U.S $ 1 = Rs 9.52
A KUNHAR 1980
B THERMAL
U.S. $ 1 = Rs 4.76
A. KUNHAR 1980
B THERMAL
10
20
30
40
50
60
70
80
COST OF THERMAL FUEL (U.S. CENTS PER MILLION BTU)
(R)IBRD-3416

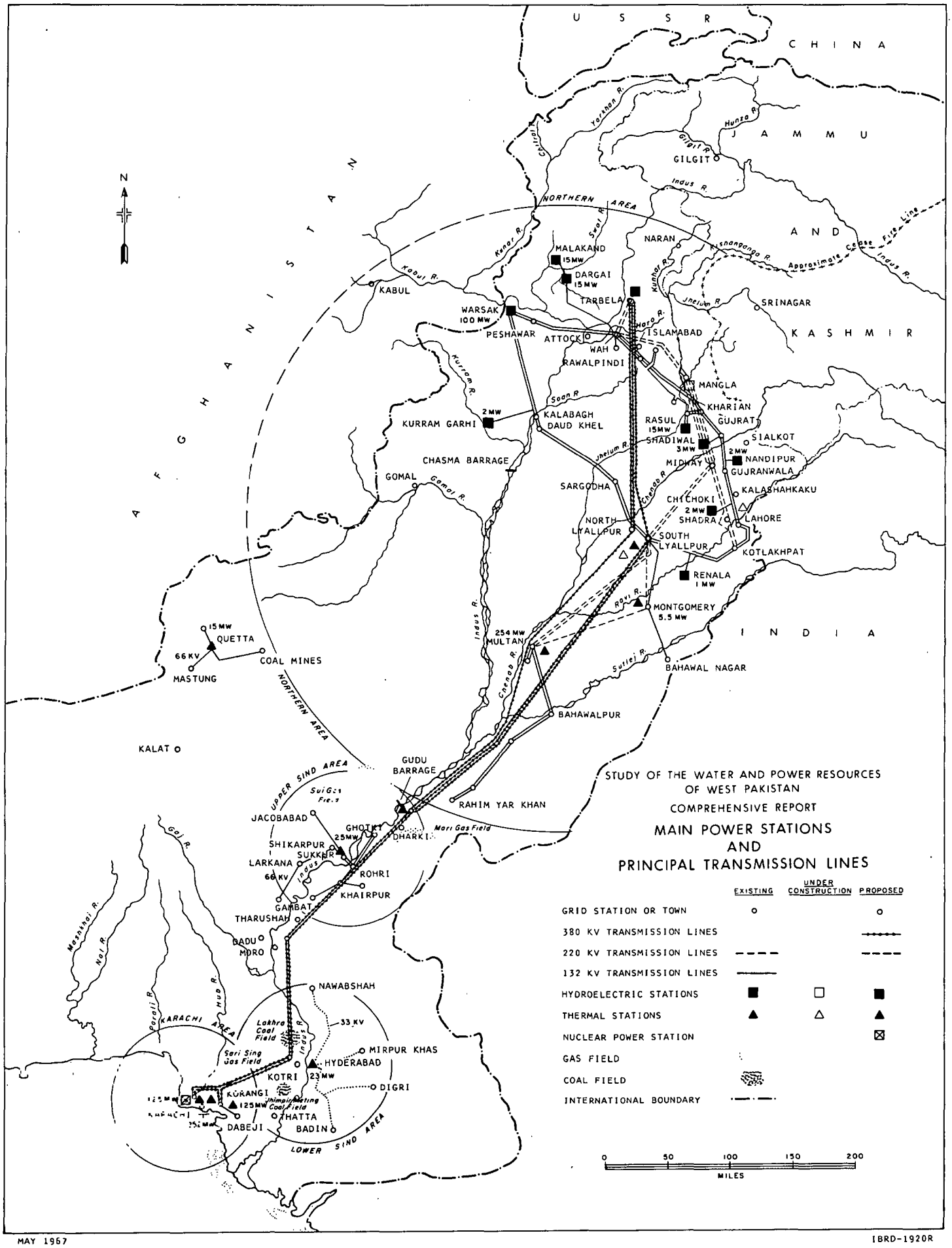
7.55 This program foresees substantial thermal development in the vicinity of the Mari and Sui gas fields in the early 1980's, despite the fact that it might not be possible to guarantee to gas-fired plants established at this time a lifetime supply of gas for high load factor operation. Currently known reserves would, according to the Bank Group's projections of total consumption of gas, be exhausted by about 1995-2000. There is of course a possibility that more gas may be discovered over the intervening 15 years. But even if gas reserves prove to be as estimated in 1966, it would appear that continuation of thermal development in the Upper Sind area in the early 1980's would be economic. In the first place the capability at Mari, apart from that designed to meet the relatively small local load, would be for the purpose of meeting seasonal peaks in the North and for supplementing base-load supplies of hydro energy and nuclear energy in the South. Therefore the load factor on the Mari plant would not be very high. If gas reserves appeared to be becoming short, it would be possible to keep the load factor on the units there down by developing further hydro plants or nuclear installations to meet base load. Secondly, even if gas reserves available for power use were completely exhausted the Gudu location would be quite suitable for generation on the basis of imported fuel oil to meet seasonal peaks in the North. Conversion of gas-fired plants to the use of oil is not expensive. Moreover, if imported fuel oil did have to be used to generate power to meet seasonal peaks in the North, its use at Gudu instead of in the Northern Grid area itself would save a lengthy rail haul. The exact proportions of plant that should be based on gas, imported oil or coal or able to use both oil and gas will, of course, depend on many unforeseeable factors. The tighter the gas situation the more attractive it would be, for instance, to use Lakhra coal for thermal generation for Karachi and the Sind intermediate between base load and peak load. Nevertheless, the concept of a heavy concentration of thermal development in the Mari/Sui area is one that seems well adapted to making the most economic use of known resources in West Pakistan, while it also has the advantage of providing a high degree of flexibility for meeting future contingencies.

7.56 A summary of the Bank Group's Power Program for the entire period 1966-85 for the North, Upper Sind (Mari/Sui) and for the Karachi-Hyderabad area is given in the following table.

Table 72

Summary of Program
Power Generating Equipment and Transmission Line Installation
(mw)

	Generating Equipment						
	Northern Grid		Upper Sind		Lower Sind and Karachi		EHV KV Transmission Line
1966	Existing	467(Oct)	Existing	50(Dec)	Existing	280(Dec)	
1967	Lyallpur-Steam	124			Hyderabad-Steam	15	
	Mangla 1, 2	90(Mar)			Kotri GT	13	
1968	Lahore GTs	52			Kotri GTs	26	
1969	Mangla 3	45(Mar)			Korangi C	125	
1970	Mangla 4	45(Mar)	Mari-Steam	100	Hyderabad GTs	26	
	Mangla 5, 6	90(Mar)					
1971	Retire	(15)	Mari-Steam	100	Karachi-Nuclear	25	Lyallpur-Mari-Karachi (s/c)
1972					Karachi-Nuclear	100	
1973	Mangla 7, 8	90(Mar)			Retire	(15)	
1974			Mari GTs	200			Mari-Karachi (s/c)
1975	Tarbela 1, 2	180(Mar)			Korangi 4	125	Tarbela-Lyallpur (s/c)
1976	Tarbela 3, 4	180(Mar)					Lyallpur-Mari (s/c)
1977			Mari/Sui 5	200			
1978	Critical changes to May						Tarbela-Lyallpur (s/c)
	Tarbela 5, 6	146(May)					
	Warsak 5, 6	80(May)					
1979	Tarbela 7, 8	146(May)			Korangi 5	200	Lyallpur-Mari
1980	Tarbela 9, 10	146(May)					Tarbela-Lyallpur (s/c)
	Tarbela 11, 12	146(May)					
1981					Korangi 6	300	
1982			Mari/Sui 5a	200			
1983			Mari/Sui 5b	200	Karachi-Nuclear	400	
1984			Mari/Sui 6	300			
1985					Karachi-Nuclear	400	


U S S R
C H I N A
J A M M U
A N D
K A S H M I R
I N D I A
A F G H A N I S T A N
N
GILGIT
Indus R.
Hunza R.
Gilgit R.
Yarkhun R.
Chitral R.
NORTHERN AREA
Swat R.
Kunar R.
Kabul R.
KABUL
NARAN
Kunhar R.
Kishanganga R.
Approximate Cease Fire Line
SRINAGAR
Jhelum R.
MALAKAND
15MW
DARGAI
15MW
TARBELA
WARSAK
100 MW
PESHAWAR
ATTOCK
WAH
RAWALPINDI
ISLAMABAD
Haro R.
Kurram R.
KURRAM GARHI
2 MW
KALABAGH
DAUD KHEL
Soan R.
MANGLA
KHARIAN
GUJRAT
RASUL
15MW
SHADIWAL
3MW
SIALKOT
2MW
NANDIPUR
MIDWAY
GUJRANWALA
CHASMA BARRAGE
GOMAL
Gomal R.
SARGODHA
Chenab R.
KALASHAHKAKU
CHICHOKI
2 MW
SHADRA
LAHORE
NORTH LYALLPUR
SOUTH LYALLPUR
KOTLAKHPAT
RENALA
1 MW
Ravi R.
MONTGOMERY
5.5 MW
254 MW
MULTAN
Sutlej R.
BAHAWAL NAGAR
BAHAWALPUR
15 MW
QUETTA
66 KV
MASTUNG
COAL MINES
NORTHERN AREA
KALAT
GUDU BARRAGE
RAHIM YAR KHAN
UPPER SIND AREA
Sui Gas Field
JACOBABAD
GHOTKI
25MW
DHARKI
Mari Gas Field
SHIKARPUR
SUKKUR
LARKANA
66 KV
ROHRI
KHAIRPUR
GAMBAT
THARUSHAH
BADU MORO
Gaj R.
Mashkhaj R.
Nal R.
Hub R.
Porali R.
NAWABSHAH
33 KV
KARACHI AREA
Lakhra Coal Field
Sari Sing Gas Field
MIRPUR KHAS
HYDERABAD
23 MW
KOTRI
DIGRI
KORANGI
125MW
Jhimpir Lignite Coal Field
KARACHI
256 MW
THATTA
DABEJI
BADIN
LOWER SIND AREA
STUDY OF THE WATER AND POWER RESOURCES OF WEST PAKISTAN
COMPREHENSIVE REPORT
MAIN POWER STATIONS AND PRINCIPAL TRANSMISSION LINES
EXISTING
UNDER CONSTRUCTION
PROPOSED
GRID STATION OR TOWN
380 KV TRANSMISSION LINES
220 KV TRANSMISSION LINES
132 KV TRANSMISSION LINES
HYDROELECTRIC STATIONS
THERMAL STATIONS
NUCLEAR POWER STATION
GAS FIELD
COAL FIELD
INTERNATIONAL BOUNDARY
0
50
100
150
200
MILES

VIII. THE DISTRIBUTION PROBLEM

WAPDA's Area

8.01 Besides projecting future power loads Stone & Webster also made estimates, shown in the following table for the WAPDA area, of the numbers of new domestic and commercial customers who would have to be connected: 477,000 by 1970 and 671,000 between 1970 and 1975. In addition, they programmed 23,450 agricultural tubewells for installation by 1970 and another 38,985 by 1975. In order to attain this number of new domestic and commercial customers, as well as a total of 45,000 new industrial customers by 1975, and in order to permit the proper functioning of the desired number of tubewells, Stone & Webster estimated that at least 20,000 miles of line would have to be constructed by 1970 and another 35,000 miles by 1975.

Table 73

Stone & Webster Forecast of West Pakistan Domestic and Commercial Customers 1965-85 Excluding Karachi
(in 000's)

Year	North	Sind & Baluchistan	Total
1965	566	67	633
1970	981	129	1,110
1975	1,548	233	1,781
1980	2,209	403	2,612
1985	2,958	628	3,586

8.02 However, even as they were making these forecasts, Stone & Webster said they believed that a total of 16,000 miles of new distribution lines during the period 1965-70 would constitute a maximum feasible effort by WAPDA. A figure of 16,000 miles of new distribution line (of all categories) would imply an average of 3,200 miles per year and would, in Stone & Webster's view, represent a doubling of the rate achieved in the period 1960-65. Thus, from the start, Stone & Webster felt that the distribution program would fall short of their goal by a minimum of 4,000 miles of line. They believed that about 10,000 miles out of this 16,000 maximum would service tubewells in the Third Plan period, while about 20,000 miles of line would perform the same service in the Fourth Plan period. IACA, in turn, adopted rates of tubewell installation which were consistent with those electrification constraints foreseen by Stone & Webster.

8.03 To a large extent Stone & Webster's pessimism about electrification rates sprang from their sense of the overall inadequacy of the distribution system in West Pakistan. They felt that the Power Wing of WAPDA had concentrated most of its efforts towards large projects involving power production at the neglect of the electric distribution system. There had, in their view, been a general lack of funds for distribution, a lack of training, improper advice, misdirected efforts and so large a demand for new services that facilities were overtaxed in an attempt to meet new requests.

8.04 But, to some extent also, Stone & Webster's projections of future rates of electrification were based on the statistics available to them at the time they prepared their report. Those statistics as indicated in para. 8.02 above, showed that during the period 1960-65 WAPDA constructed an average of 1,600 miles of new 400-volt and 11-kv distribution line per year and that the number of miles never exceeded 2,000 in any one year.

8.05 Since Stone & Webster completed their study, the Bank Group has obtained more recent information from WAPDA, relating to the expansion of the WAPDA distribution system between 1960 and 1966. The table below shows the total numbers of customers served by WAPDA in each year and the increase in the number of customers for different classes of consumption and the number of new villages electrified each year. The figures indicate that WAPDA has been making over 80,000 new connections since 1961 and over 110,000 new connections in 1965/66. The number of new villages electrified each year ranged from 85 to 351. The statistics arrived too late to be checked or evaluated by the Bank Group.

Table 74

Number of Customers Served by the WAPDA Distribution System 1960-66

	June 30 1960	June 30 1961	June 30 1962	June 30 1963	June 30 1964	June 30 1965	June 30 1966
Bulk	81	106	102	121	165	206	306
Public Lighting	200	218	244	260	356	400	497
Agricultural	3,300	4,663	7,997	9,957	13,519	16,712	21,914
Industrial	13,191	15,808	19,658	23,995	28,583	33,569	41,317
Domestic	294,824	338,593	413,970	485,653	489,041	516,020	595,331
Commercial					74,698	120,959	142,110
TOTAL	311,596	359,388	441,971	519,986	606,362	687,866	801,475
Villages Electrified	904	1,255	1,491	1,654	1,739	1,857	2,052
Additions During Year							
Villages Electrified	351	236	163	85	118	195	
General Consumers (Dom.+Com.)	43,769	75,377	71,683	78,086	73,240	100,462	
Total Consumers	47,792	82,583	78,015	86,376	81,504	113,609	

8.06 Table 75 gives the other side of this picture: WAPDA's construction performance measured by route miles of distribution lines. It shows that some 9,100 miles of 11-kv line and about 5,600 miles of 400-volt line were installed in the last five years.

Table 75

Distribution Lines -- Construction Performance by WAPDA

Public Sector Tubewell Areas	1960/ 61	1961/ 62	1962/ 63	1963/ 64	1964/ 65	5-Year Total
11-kv lines (miles)	900	640	146	-	120	1,806
400-volt lines (miles)	-	-	-	-	-	-
Estimated number of public tubewells connected	1,000	800	163	-	138	2,101
Private Tubewells and[a] Urban Area Distribution						
11-kv lines (miles)	850	860	569	3,531	1,480	7,290
400-volt lines (miles)	876	876	1,065	1,735	1,055	5,607
Miles of line per public tubewell connected				0.9 miles		

a/ The private tubewells are mostly fed by 11-kv lines supplying electric power both to rural and urban areas. Therefore a combined figure of line mileage has been given in this statement.

Karachi

8.07 Stone & Webster's projections of residential and commercial customers in Karachi are shown below, for the period 1965-85.

Table 76

Forecast of Residential and Commercial Customers in Karachi
(in 000's)

	1965	1970	1975	1980	1985
Karachi	120	183	266	383	535

8.08 This forecast can be related to the recent performance of KESC in the field of distribution expansion. The table below presents the most recent information available to the Bank, together with KESC's own forecast.

Table 77

Distribution Expansion in Karachi
(Miles of Line)

	Year	11 kv Overhead	11 kv Underground	400 volt Overhead	400 volt Underground	Total
Actual	1961	39	250	657	55	1,001
	1962	53	274	699	59	1,085
	1963	69	291	750	62	1,172
	1964	90	315	810	64	1,279
	1965	103	339	893	67	1,402
KESC Forecast						
	1966	120	360	985	72	1,537
	1967	160	400	1,075	77	1,712
	1968	180	430	1,150	85	1,845
	1969	210	460	1,250	90	2,050
	1970	245	500	1,375	95	2,215

Evaluation of Stone & Webster's 'Maximum'

8.09 Stone & Webster's 16,000 maximum figure does not, of course, include Karachi. The distribution problems and possibilities in Karachi are very different from those of the WAPDA area. The maximum figure has rather to be looked at in the light of Tables 74 and 75. At first sight, it might appear that this 16,000 maximum is unduly pessimistic in that, according to Table 75 the actual mileage achieved by WAPDA is already almost at an annual average rate which Stone & Webster believed constituted a feasible maximum.

8.10 But before any substantial doubt is thrown on Stone & Webster's conclusions about the rate of distribution expansion, an important observation must be made. Tables 74 and 75 above indicate a substantial achievement as far as agricultural connections are concerned. The total of agricultural consumers grew from about 3,300 in 1960 to 22,000 in 1966. However, in recent years the rate of connection of public tubewells appears to have declined from 1,000 in 1960/61 to 138 for the two years 1963/64 and 1964/65, and the rate of village electrification has also declined from the levels achieved during the earlier years of the 1960's.

8.11 It would seem, therefore that whatever the performance in the field of urban distribution, there remains a real difficulty in making rural connections, either under the village electrification program or under the tubewell program. Stone & Webster recommended that these programs be combined. They felt that, in this way, higher rates of village electrification could be achieved in that the two programs covered roughly the same areas of the Indus Plains. Nevertheless, it remains true that, whatever the administrative organization, the electrification of rural customers in general and of tubewells in particular is a process

making great demands on financial resources (see Chapter IX) and on trained manpower.

8.12 After reexamining the size of the distribution problem the Bank Group concludes that Stone & Webster has quite properly drawn IACA's attention to a serious implementation constraint and that achievement of the targets set in this report for the increase in the numbers of private and public tubewells will require a greatly expanded effort by WAPDA on the distribution side.

Specific Problems

8.13 Stone & Webster pointed out some other specific problems regarding distribution which require special emphasis. These are:

Voltage Regulation

8.14 According to Stone & Webster little has been done about improved voltage regulation although the need is recognized. Systems which have long lines such as WAPDA's, require supplementary regulation which can best be accomplished at the distribution substation. The cost of distribution regulators is recovered by enabling regulated circuits to carry more load and maintaining utilization voltage within reasonable ranges. Unfortunately most new installations are being made without proper voltage control, which will result in poor service to customers at an early date.

House Wiring

8.15 Although regulations for house wiring are in general adequate and although there is an inspection system, house wiring in West Pakistan is reported to be generally deficient and often dangerous. Poor wiring practices and poor workmanship appear to be the principal reasons for the deficiencies. Better training of workmen and more rigorous inspection should be undertaken. Because of the dangerous situation that exists inspectors should concentrate more on detecting and preventing the overloading of circuits.

Rural Distribution Voltage

8.16 Much thought has been directed within WAPDA towards changing from an 11-kv three-wire system to an 11-kv grounded-neutral four-wire scheme. Stone & Webster fail to find merit in shifting to the four-wire system at 11 kv because the savings gained from use of single-phase-to-neutral distribution are relatively small.

8.17 Stone & Webster recommend that serious study be given at an early date to raising the standard voltage of the rural distribution system from 11 kv to 19 kv or higher. The advantages of the higher voltage would be mainly in cost savings. Rural load densities will be relatively low -- about 60 to 70 kw per square mile -- and the higher distribution voltage

would make possible larger loads per substation, reducing unit costs. Larger substation loads could justify direct transformation from 132 kv to distribution voltage, rendering unnecessary the intermediate 66-kv lines in many areas. With the higher voltage a four-wire grounded-neutral scheme would probably be more appropriate. Because many miles of distribution line will be constructed in the next ten years early decision about distribution voltage is needed.

Maintenance

8.18 A good maintenance program is one key to providing good service. Maintenance includes such functions as patrolling lines and correcting faults revealed by the patrol, tree trimming, setting relays, testing circuit breakers, and replacing overloaded equipment. New installations remain relatively troublefree for several years but then begin to require attention. Stone & Webster believe that maintenance has not been adequate within WAPDA.

Training Program

8.19 Much attention and time have been given to training but results have been disappointing and the fault probably lies in trying to do too much. Some areas of concentration are to:

1. Teach a few subjects at one time.
2. Concentrate on physical skills such as use of hand tools.
3. Restrict hot-line instruction to the 400 volt circuit until other physical skills are learned.
4. Train cadres and send them into fields to teach others.
5. Establish more 'dummy' training sites using practice setups such as the one at Kotlakhpat. Participation in tasks is a key to training.

8.20 The Bank Group generally agrees with these observations of Stone & Webster about the problems confronting WAPDA and suggests that WAPDA (to the extent it has not already cone so) take the necessary steps to correct these deficiencies which act as distinct constraints on the power program over the next two decades.

IX. TARIFFS AND ORGANIZATION

WAPDA Tariffs

9.01 As will be pointed out in Chapter X below, the total capital requirements during the period 1965/66-1969/70 of the Stone & Webster Power Program were estimated at PRs 2,875 million and those of the Bank Group's adjusted Program at PRs 3,017 million while the Third Plan had originally allocated only PRs 2,178 million for power. Since the respective power programs of Stone & Webster, of the Bank Group and of the Planning Commission cannot, as discussed above in para 4.74, diverge very substantially over this short-term period, Stone & Webster did not consider that the PRs 2,178 million would provide sufficient funds to carry out the program for power outlined in the Third Five Year Plan. They believed that either the funds allotted would have to be increased or portions of the program curtailed. Since Stone & Webster completed their report, the allocation for power in the Third Plan had been increased to PRs 2,416 million.

9.02 A suggestion that allotted funds should be increased inevitably raises the question of the appropriateness of the level and structure of tariffs.

9.03 The WAPDA Act of 1958 sets forth the basis for WAPDA's tariffs. The pertinent part of the Act regarding tariffs is as follows:

> "The rates at which the Authority shall sell power shall be so fixed as to provide for meeting the operating costs, interest charges and depreciation of assets, the redemption at due time of loans other than those covered by depreciation, the payment of any taxes and a reasonable return on investment."

9.04 In 1965 Harza made a study of WAPDA's tariffs and presented a report to the General Manager of Power dated April 28, 1965. The report stated that in each fiscal year since 1960/61 WAPDA's revenues have been sufficient to cover all operating expenses and it has paid all interest charges as they became due. It observed that under the present tariffs, WAPDA has complied with the requirements laid down in the Act of 1958. The rate of return as computed by Harza was shown to average 9.93 percent for the four years.

9.05 Harza calculated the rate of return as the ratio between the sum of funds available for depreciation, interest and allocation to surplus in a year and the average investment in plant in service; plant was valued gross of depreciation for the year. The Bank Group recalculated WAPDA's rate of return in a manner that is more standard among electrical utilities around the world. Returns were taken as consisting simply of funds available for interest payments and allocation to surplus, i.e. excluding depreciation. The capital base, average investment in plant in service, was taken after deduction of depreciation for the year in question. The ratio between these two items is the rate of return normally used by the Bank.

9.06 WAPDA's rate of return, when recalculated by the method which the Bank uses, averaged 7.58 percent for the four years since 1960/61 instead of 9.93 percent as calculated by Harza. For the latest year, 1964/65, for which financial information is available WAPDA's rate of return on net

fixed assets in operation declined to 5.83 percent according to the Bank's method of computation.

9.07 When Harza presented their report they did not recommend any major changes in the tariff structure. They proposed the elimination of certain anomalies and inequities in that structure but, essentially, their report focused more on the reduction of losses by improving the administration of the system than on raising revenues by increasing the rates.

9.08 They recommended that: a) because of the difficulties in obtaining reliable information as a basis for the current tariff study, studies should be undertaken with a view to reforming the present irregular meter reading practices; b) mechanical or electronic billing should be introduced in all areas and customer accounting and collection procedures should be improved; c) reports should be made for the number of bills issued and the kwh consumption for each month for each rate classification and also for the total amount billed; and d) a more detailed system of accounts should be introduced to give a clearer picture of all phases of current operations each month and to make it possible to determine the cost of rendering various types of services.

9.09 In substantiation of these recommendations, Harza stated that an analysis of WAPDA's energy account showed that for the fiscal year 1963/64 the losses and unaccounted for were 22.8 percent of the kwh sent out from generating stations. These losses represented not only electrical losses in transformation, transmission and distribution but also losses by diversion, inaccurate meter reading and billing. No information was available to Harza to show to what extent each of these factors contributed to the high percentage of energy loss but they observed that a one percent reduction of this loss in the fiscal year 1963/64 would have meant a potential increase in sales of 19 million kwh and PRs2.16 million in revenues.

9.10 If the losses could be reduced to about 15 percent of the total kwh sent out, the improvement in income in 1963/64 would have amounted to PRs16.8 million or about 50 percent of the actual net earnings in that year.

Observations of the Bank Group

9.11 The Bank Group and its consultant Stone & Webster are in substantial agreement with the recommendations of Harza: they recognize that corrective measures must be taken to reduce the heavy losses in the system (see para 4.48). They are aware that WAPDA's present accounting system does not provide management with condensed integrated monthly financial and statistical statements containing sufficient detail to analyze operating results and trends. They support the emphasis Harza has placed on the need for a general improvement of the electrical and commercial efficiency of the power system.

9.12 At the same time the Bank Group's recalculation of the rate of return earned by WAPDA, together with its appreciation of the large capital expenditure which WAPDA will be required to make to carry out its very heavy program of system expansion, has led it to emphasize the possibility of a revision in the level and structure of WAPDA's tariffs.

9.13 The agricultural tariff is a case in point. Harza had pointed out in their report that the bills under the agricultural tariff were 44 percent lower than the bill which a consumer would pay for the same load and consumption under the industrial rate B 1-1 (which applies to industrial supplies at 400/230 volts to consumers with connected loads up to 30 kw) and 37 percent lower than a consumer would pay under the industrial rate B 1-2 (which applies to industrial supplies at 400/230 volts to consumers with connected loads between 30 kw and 70 kw). They had recommended that supply under the present agricultural tariff should be available only to those agricultural consumers who agree to discontinue operation of their pumps during critical load periods.

9.14 This change of practice, even though it involved no increase in rates, was not accepted by WAPDA when, in July 1965, it adopted Harza's other recommendations. The Bank Group feels, therefore, that it must stress this issue once again -- in a different way. It points out that other consumers must at present bear the burden of the subsidy which is granted to agricultural pumping. As pumping requirements are estimated to increase substantially in the next decade, WAPDA will find that this burden will no longer be able to be carried within the present rates charged for electricity to its non-agricultural consumers. If it is to comply with the provisions of the 1958 Act, WAPDA will find in the near future that it must either (a) raise agricultural pumping rates to at least a break-even point, or (b) raise rates to some or all non-agricultural classes of consumer, or (c) ask that the subsidy be covered by allocations from the Government.

9.15 The Bank Group believes that in deciding which of these alternatives to adopt, as well as in its other policy issues relating to tariffs, WAPDA should carefully consider the financial demands that the expansion of power facilities will place upon its resources. In particular, WAPDA should recognize that large amounts of local currency will be needed. In these circumstances, the Bank Group feels that a rate of return of not less than 8 percent (computed by the Bank's method) should be WAPDA's goal.

KESC Tariffs

9.16 KESC's requirements for its expansion program for the period 1966-70 are estimated to amount to PRs342.75 million (US$72 million). It is expected that 54 percent of this sum will come from internal cash generation, about 43 percent from borrowings and the remainder from capital receipts (mostly customer payments for connections, deposits etc.).

9.17 For KESC to provide from internal cash generation funds in the amounts expected in the next five years, it will need adequate tariffs. The Bank Group feels that such adequate tariffs are in fact provided for in the report of KESC's consultant, Gilbert Associates Inc., which was presented in July 1966.

9.18 The purpose of Gilbert's Study, authorized in September 1964, was to present KESC with a new schedule of tariffs to supersede and simplify the schedule then in existence. The basic rates had been established many years ago and the increases allowed by the Government in

1953 were applied in varying percentage amounts to different tariffs. This not only placed the tariffs out of line with each other but also continued the inequity of some of the low charges.

9.19 In general, KESC's consultants pointed out that the present tariffs are extremely complex, hard to understand, and difficult to use in calculating bills. Some of the rates are based upon horsepower of connected load, some upon horsepower of demand and some upon kilowatts of demand. Some of the charges in paisa run to five decimal places. Some rates are gross with a discount for prompt payment while others offer no discount. The fuel adjustment is a large portion of an industrial consumer's bill because the present base was established some years ago when fuel was cheaper.

9.20 Some of the anomalies in the present rate structure are illustrated by the following:

a) A commercial consumer, such as a shop or small office building, must buy lighting services on one rate and power for pumps, elevators and air conditioners on any one of four other rates depending upon the total horsepower.

b) A residential consumer buys lighting services on a rate identical with the commercial lighting rate and appliance service and power on one of the same four alternative rates applicable to commercial customers.

c) Cinemas are served on a combined light and power rate, although other users of similar size must take light and power service separately on different rates.

d) Large users have a choice of high tension or low tension service, but the difference in price is so slight that some will not invest money in a substation to take advantage of the lower, high tension rate.

9.21 The rate changes proposed by Gilbert would simplify all of the rates mentioned above and would ensure that there would be proper differentials between service at various voltage levels to attract high tension industrial service by major industrial consumers.

9.22 Gilbert observed that the KESC electric rates were often compared with those of WAPDA. A comparison of KESC and WAPDA rates is difficult because they are of different types and KESC's are complex. A rough calculation by Gilbert indicated that the KESC rates are, on the whole, about 12 percent lower than the WAPDA rates which became effective on July 7, 1965.

9.23 After considering several alternatives, Gilbert decided to recommend a schedule of rates for the different classes of service that is similar in form to WAPDA's rate schedule but generally lower in price.

9.24 Gilbert proposed seven rates which would supersede 11 of the existing rates. The present complex system of basing the monthly minimum bill on rooms and connected load would be abandoned and a minimum monthly bill of one rupee would be substituted for residential and commercial consumers. Some of the recommendations which merit special attention are:

a) the elimination of free energy in some tariffs;

b) the use of kilowatts instead of horsepower for demand;

c) service through one meter at one tariff for residences and small commercial users;

d) lower charges for high tension service than for low tension;

e) revision of fuel adjustment to bring it in line with present costs of fuel;

f) the abandonment of several tariffs for residential and commercial consumers and;

g) the institution of a uniform discount for prompt payment of bills.

9.25 Gilbert stated that the proposed tariffs were designed primarily for simplicity and ease of computation and incidentally to produce as little change in revenues as possible. On the whole it is estimated that the new tariffs might yield about five percent more than the existing tariffs. The residential class as a whole was estimated to yield about three percent less revenue while other classes were estimated to yield a little more than with existing tariffs.

9.26 The Bank Group agrees with the approach of KESC's consultant as outlined in para. 9.25 above. It feels that even though KESC's tariffs have not been changed since 1953, they are still producing adequate revenues.

9.27 The rate of return on average net fixed assets in operation (before provisions for income tax) ranged between 10.6 and 13.4 percent during the 1960-64 period, falling off in 1965 to 10.2 percent. KESC declared cash dividends of 10 percent each year through 1962. Because of a large increase in the required allocations to a special tax reserve there was not enough cash surplus in 1963/64 to declare cash dividends. Stock dividends of 10 percent were declared in 1963 and 1964. In 1965 a combination of six percent cash and four percent stock dividends was declared.

9.28 Nevertheless the Bank Group recognizes that this relatively comfortable situation may change. While the cost of doing business has risen, the average revenue received per kwh has declined from 14.67 paisa (3.1 cents) in 1954 to 12.09 paisa (2.5 cents) in 1964, and the

differential may become greater. Furthermore, generous tax exemptions have been allowed KESC against new facilities placed in service and these exemptions may at some time in the future be withdrawn.

9.29 As noted above, the Bank Group approves of the new tariff structure recommended by KESC's consultant and recommends that the Government of Pakistan agree to them. At the same time the Bank Group believes that the Government should permit KESC to charge tariffs so as to maintain revenues sufficient to provide for an annual rate of return of at least eight percent on its average net fixed assets in operation. It might therefore be necessary to adjust this new schedule of tariffs up or down to fit changing conditions.

The Organization of the Power Sector

9.30 The preceding paragraphs, 9.08-9.11, should have made it clear that both the Bank Group and Stone & Webster, as well as Harza, believe that there should be a general improvement in the electrical and commercial efficiency of the power system, especially on the side of distribution in the Northern areas. That belief seems also to be shared by the Government of Pakistan. Recognizing that WAPDA's staff may become over-extended in the future, the Government has appointed a committee to examine whether or not WAPDA might be relieved of some of its responsibilities.

9.31 The Bank Group would readily agree that WAPDA's responsibilities are wide and various. WAPDA's powers and duties, as defined in the establishing Act of 1958 as amended, are to investigate, survey, plan and execute schemes for all of the following:

i) irrigation, water supply and drainage and recreational use of water resources;

ii) the generation, transmission and distribution of power, and the construction, maintenance and operation of powerhouses and grids;

iii) flood control;

iv) the prevention of waterlogging and reclamation of waterlogged and salted lands and;

v) the prevention of any ill effects on public health resulting from the operation of the Authority.

9.32 In addition to the above, WAPDA acts as agent for the West Pakistan Government to provide technical supervision and administrative and financial control of any scheme or project entrusted to it. WAPDA is also administering on behalf of the Government of Pakistan the Indus Basin Projects involving two major dams, eight inter-river link canals, five barrages, one gated syphon, remodeling of three existing link canals, two existing headworks and some existing canals affected by the new construction. The estimated cost of the Indus Basin Project is about 1,925 million dollars.

9.33 WAPDA's Power Wing manages a major power system serving in 1965 about 688,000 customers and supplying 66 percent of the energy generated in the Province (see para 2.09).

9.34 The Bank Group recognizes that, as demands upon it increase, WAPDA may find it difficult to continue to manage all the activities listed above efficiently. It has examined briefly the two proposals which are under consideration by the Committee, namely (1) to relieve WAPDA of all responsibility for the operation of the power system as well as the distribution and sale of electricity, and (2) to leave WAPDA with the responsibility for operating the system but to relieve it of responsibility for sale and distribution of electricity.

9.35 The Bank Group feels that either of these two proposals would require the creation of a new entity and the recruitment of a highly competent managerial staff. As experienced staff would not be obtainable elsewhere, it is obvious that large numbers of WAPDA's existing staff would have to be transferred to the new organization. Such a transfer at the present time would have unfortunate consequences.

9.36 In the first place, it would result in delays in the execution of WAPDA's distribution program at a time when WAPDA had made definite plans for undertaking improvements and expansion. It would occur also at a time when large amounts of new generating capacity were becoming available.

9.37 Secondly, the new organization would itself have numerous problems. It would have to recruit additional managerial talent which is scarce in West Pakistan. It might find it hard to raise money by borrowing because of its lack of financial background. It might also be difficult initially for the new organization to cope with the many complexities involved in power operations and in distribution and sales. This would result in some confusion and contribute to the delay in the execution of the distribution program.

9.38 For reasons stated above, the Bank Group is not convinced that any of the responsibilities of the Power Wing of WAPDA should be transferred to a new organization at the present time. While it is recognized that WAPDA's responsibilities are varied and numerous, the Bank Group feels that the Power Wing has done a reasonably good job in carrying out its responsibilities under rather difficult circumstances. WAPDA is relatively young and it has had to build up its organization rather rapidly. Through trial and error it has gained much valuable experience. It would be more prudent, the Bank Group believes, for the areas of weakness in the Power Wing's organization and functions to be strengthened rather than to create a new organization to relieve the Power Wing of some of its functions. It would probably be inevitable that much time would elapse before the new organization could function efficiently and the present is no time to add yet another agency in the power field. As very large amounts of hydro and thermal power will become available in the near future, there would be too much at stake to risk a delay in providing adequate transmission and distribution facilities for the efficient marketing of this energy and for the overall coordination of the various facets of the power system under WAPDA's jurisdiction.

9.39 The Power Wing should, in order to operate at a high level of efficiency, have adequate authority to make decisions that would normally be made by the management of a commercial power company. This would require the delegation of more authority to the Power Wing so that it can make expeditiously all operational decisions except the most important decisions on major questions of policy such as overall budget requirements.

9.40 In considering the overall organizational aspects of the power system it is obvious that with the advent of EHV transmission lines interconnecting the North and South, there must be plans for the establishment of a central dispatching station. The location of the station should be carefully studied and it should be staffed with a chief dispatcher clothed with adequate authority to order the various generating stations to supply energy or to close down as required to meet the varying demands for energy at load centers in the North and South.

X. THE FINANCIAL REQUIREMENTS OF THE POWER DEVELOPMENT PROGRAM

10.01 On the basis of the Third Five Year Plan documents the Bank Group estimated that the amounted budgeted for public and private investment in power between 1965/66 and 1969/70 inclusive was PRs 2,178 million. The effect of the revision of plan allocations, published in December 1966, is to raise this figure by some PRs 240 million. The table below shows the original and revised figures.

Table 78

Third Five Year Plan Allocations for Power Programs
(Million PRs)

	Original Allocation May, 1965	Revised Allocation December, 1966
Public Sector -- Power	1,688	1,926
Nuclear Energy -- Central Government	240 a/	240 a/
Private Undertakings	250	250 a/
Total	2,178	2,416

a/ Estimated in absence of actual figures.

10.02 The figures above compare with PRs 3,017 million, which the Bank Group estimates to be the total public and private investment cost of its recommended program during the Third Plan period. 1/ The Bank Group's figures for the cost of its recommended program are based directly on the unit cost estimates of Stone & Webster. The figures cover the costs of four types of facilities: generation, transmission, distribution and general plant (buildings, offices, tools, transport, communications, etc.). All capital costs are covered from the generator to the meters on customers' premises; only customers' house or building wiring and appliances are excluded. The costs included for the hydroelectric units cover civil engineering works for power -- steel tunnel liners, penstocks, tailrace, power house structure, etc. -- as well as all mechanical and electrical equipment for the power plant. The estimates included allowances for contingencies of 10 percent for hydro generation and 5 percent for thermal generation. No specific contingencies were allowed for transmission, distribution or

1/ The costs of the Bank Group program for the Third Plan period do include about PRs 115 million for completing Mangla units 1, 2 and 3. The official Plan figures given in Table 78 probably do not include costs of these units since they are being borne by the Indus Basin Development Fund.

general plant. The figures used are not intended to be detailed cost estimates, but rather general order of magnitude indicators in terms of 1965 prices. For the sake of comparability with Plan figures on total investment, allowances are included here to cover import duties, taxes and interest during construction at six percent.

10.03 Table 79 compares the estimated costs of the public portion of the power program (i.e. excluding industrially owned generation) with some preliminary estimates that were made available to the Bank Group by the Pakistan Planning Commission regarding anticipated total investment in West Pakistan over the Third and subsequent Plan periods up to 1985. Table 79 also shows the capital expenditures by the public sector on electric power during the Second Plan period and compares them with total investment over those years, as given in the Planning Commission's "Evaluation of the Second Five Year Plan" (May 1966).

Table 79

Actual and Projected Public Investment in Power Compared to Total Investment (Public & Private) in West Pakistan 1960-1985
(Million PRs)

Actual	Public Investment in Power	Total Investment (Public & Private)	Power as a % of Total
1960/61	208	3,023	6.8
1961/62	273	3,528	7.7
1962/63	213	4,410	4.8
1963/64	258	4,753	5.4
1964/65	242	5,260	4.6
Subtotal Second Plan	1,194	20,974	5.7
Projected by Bank Group			
Third Plan	2,849	27,250	10.5
Fourth Plan	3,468	38,200	9.1
Fifth Plan	3,676	53,200	6.9
Sixth Plan	4,031	68,000	5.9

The table brings out the fact that the costs of the program recommended by the Bank Group, particularly for the Third and Fourth Plan periods, represent substantially higher proportions of total Plan expenditure than were devoted to public power during the Second Plan. The lag in the expansion of the distribution system and the continual shortage of generating capacity which have been experienced in the past and were discussed previously in this Volume, suggest that inadequate financial provision has been made for power in the past. The exceptionally high proportions of Plan

expenditure which, in the view of the Bank Group, should be allocated to power in the Third and Fourth Plan periods are required partly to make up the serious backlog in generation and distribution which has developed and partly to cover the costs of initiating the large EHV transmission system which the Bank Group believes will be of great value to West Pakistan in future years. The allocations in the Third Plan for distribution and for transmission appear to diverge most sharply from the expenditures which the Bank Group believes to be required.

10.04 The following tables present some breakdowns of the costs of the 20-year program recommended by the Bank Group. The costs are shown in full detail in Table 87 at the end of the chapter. Table 80 shows that distribution is the largest single item in the program in terms of expenditures involved.

Table 80

Total Costs Power Facilities 1966-85

	Millions of Rupees	% of Total
Utility Generation (including nuclear)	5,513	38.8
Transmission	2,000	14.0
Distribution	6,340	44.6
General Plant	171	1.2
Industrially Owned Plant	192	1.4
Total	14,216	100.0

10.05 The financial elements -- duties, taxes and interest during construction -- and the foreign exchange component of the costs of the Bank Group's program are separated out in Table 81.

Table 81

Economic and Financial Costs of Power Facilities 1966-85
(Million PRs)

1966-85	Utility Generation inc. nuclear energy	Transmission	Distribution	General Plant	Industrially Owned	Total
Basic Economic Cost	3,989	1,499	5,250	132	138	11,008
Duties, Taxes, Interest	1,524	501	1,090	39	54	3,208
Total	5,513	2,000	6,340	171	192	14,216
Foreign Exchange Component	3,264	996	2,380	54	111	6,805

10.06 The total foreign exchange costs of PRs 6,805 million represent about 48 percent of the total for the 20-year period. The foreign exchange components in the different five year plan periods are shown in Table 82.

Table 82

Foreign Exchange Component of Total Power Program Costs
(Million PRs)

Five-Year Periods	Foreign Exchange	Local Currency	Total Cost
1966-70	1,527	1,490	3,017
1971-75	1,631	1,845	3,476
1976-80	1,810	1,874	3,684
1981-85	1,837	2,202	4,039
Total	6,805	7,411	14,216

10.07 The total costs of the recommended program are broken down by class of expenditure and by five year plan periods in Table 83.

Table 83

Total Financial Costs of Power Facilities 1966-85 by Five Year Periods
(Million PRs)

5-Year Periods	Utility Generation (includ. Nuclear)	Transmission	Distribution	General Plant	Industrially Owned	Total
1966-70	1,053	590	1,180	26	168	3,017
1971-75	1,017	525	1,890	36	8	3,476
1976-80	1,651	566	1,410	49	8	3,684
1981-85	1,792	319	1,860	60	8	4,039
Total	5,513	2,000	6,340	171	192	14,216

Stone & Webster's Cost Estimates

10.08 As pointed out, the Bank Group's cost estimates are based directly on those prepared by Stone & Webster. The detailed cost estimates for the Stone & Webster program itself are presented in Table 86 at the end of this chapter. The differences between the costs of the two programs result largely from differences in the scheduling of investment in generation and transmission equipment and from the Bank Group's inclusion of some nuclear generating plant towards the end of the 20-year period. Table 84 summarizes the costs of the two programs by five year plan periods.

Table 84

Comparison of Cost of Stone & Webster and Bank Group Power Programs, 1966-85
(Million PRs)

5-Year Periods	Stone & Webster	Bank Group
1966-70	2,875	3,017
1971-75	3,733	3,476
1976-80	3,383	3,684
1981-85	4,167	4,039
	14,158	14,216

The Bank Group's plan for the Third Plan period is somewhat more costly than Stone & Webster's, mainly because the Bank Group includes two large EHV transmission lines -- between Mari and Lyallpur and between Mari and Karachi -- for completion in 1971, whereas Stone & Webster postponed the Mari-Lyallpur line until 1973.

Effect of a Change in the Load Forecast

10.09 Stone & Webster made an interesting analysis of the effects on capital requirements of a slower growth in demand. They estimated that a change in the load forecast of the order of magnitude indicated earlier in paragraphs 4.57 - 4.61 would result in a reduction of about PRs 3,364 million, or almost one-quarter, in the total costs of their 20-year program. Costs of the smaller program were calculated by rescheduling expenditures for generating and distribution equipment in the Third and Fourth Plan periods and applying reductions, equivalent to the reductions in peak loads in various years, to the costs of other classes of equipment and to total costs in the later plan periods. Total costs of Stone & Webster's recommended program and its reduced version are shown below by five-year periods.

Table 85

Estimated Costs of Stone & Webster's Recommended and Reduced Programs
(Million PRs)

	Original	Reduced
1966-70	2,875	2,330
1971-75	3,733	2,895
1976-80	3,383	2,613
1981-85	4,167	2,957
Total	14,158	10,794
1986-90	-	3,364
		14,158

For the 20-year period 1966-85, the foreign exchange expenditures would be reduced PRs 1,587 million from PRs 6,761 to PRs 5,174 million.

Table 86

Stone & Webster's Original Program

Capital Requirements for Electric Power in West Pakistan by Five-Year Periods, 1966-1985

(PRs million)

	Generation							
	Utility	Nuclear	Industrially Owned	Total Generation	Transmission	Distribution	General	Total
1966-1970 a/								
Cost (less Duties, Taxes and Interest)	563	230	120	913	337	960	20	2,230
Duties, Taxes and Interest Charged to Construction	227	33	48	308	111	220	6	645
Total Installed Cost	790	263	168	1,221	448	1,180	26	2,875
Foreign Exchange	469	190	96	755	225	480	10	1,470
1971-1975								
Cost (less Duties, Taxes and Interest)	828	22	6	856	457	1,530	27	2,870
Duties, Taxes and Interest Charged to Construction	329	1	2	332	162	360	9	863
Total Installed Cost	1,157	23	8	1,188	619	1,890	36	3,733
Foreign Exchange	671	20	5	696	305	760	11	1,772
1976-1980								
Cost (less Duties, Taxes and Interest)	1,053	-	6	1,059	342	1,185	38	2,624
Duties, Taxes and Interest Charged to Construction	412	-	2	414	109	225	11	759
Total Installed Cost	1,465	-	8	1,473	451	1,410	49	3,383
Foreign Exchange	850	-	5	855	230	550	15	1,650
1981-1985								
Cost (less Duties, Taxes and Interest)	1,257	-	6	1,263	382	1,575	47	3,267
Duties, Taxes and Interest Charged to Construction	482	-	2	484	118	285	13	900
Total Installed Cost	1,739	-	8	1,747	500	1,860	60	4,167
Foreign Exchange	996	-	5	1,001	260	590	18	1,869
Total for Period 1966-1985								
Cost (less Duties, Taxes and Interest)	3,701	252	138	4,091	1,518	5,250	132	10,991
Duties, Taxes and Interest Charged to Construction	1,450	34	54	1,538	500	1,090	39	3,167
Total Installed Cost	5,151	286	192	5,629	2,018	6,340	171	14,158
Foreign Exchange	2,986	210	111	3,307	1,020	2,380	54	6,761
	% of Total Installed Cost							
1966-1970				42.47	15.58	41.05	0.90	100
1971-1975				31.83	16.38	50.63	0.96	100
1976-1980				43.54	13.33	41.68	1.45	100
1981-1985				41.92	12.00	44.64	1.44	100
1966-1985				39.76	14.25	44.78	1.21	100

a/ Includes "Total Installed Cost" of PRs 114.8 mln. for completing Mangla 1,2 & 3 which is part of the Indus Basin Development Fund Agreement.

Table 87

Bank Group's Adjusted Program

Capital Requirements for Electric Power in West Pakistan by Five-Year Periods 1966-1985

(PRs million)

	Generation							
	Utility	Nuclear	Industrially Owned	Total Generation	Transmission	Distribution	General	Total
1966-1970 a/								
Cost (less Duties, Taxes and Interest)	569	230	120	919	440	960	20	2,339
Duties, Taxes and Interest Charged to Construction	221	33	48	302	150	220	6	678
Total Installed Cost	790	263	168	1,221	590	1,180	26	3,017
Foreign Exchange	469	190	96	755	282	480	10	1,527
1971-1975								
Cost (less Duties, Taxes and Interest)	696	22	6	724	392	1,530	27	2,673
Duties, Taxes and Interest Charged to Construction	298	1	2	301	133	360	9	803
Total Installed Cost	994	23	8	1,025	525	1,890	36	3,476
Foreign Exchange	581	20	5	606	254	760	11	1,631
1976-1980								
Cost (less Duties, Taxes and Interest)	1,178	-	6	1,184	425	1,185	38	2,832
Duties, Taxes and Interest Charged to Construction	473	-	2	475	141	225	11	852
Total Installed Cost	1,651	-	8	1,659	566	1,410	49	3,684
Foreign Exchange	956	-	5	961	284	550	15	1,810
1981-1985								
Cost (less Duties, Taxes and Interest)	1,294	-	6	1,300	242	1,575	47	3,164
Duties, Taxes and Interest Charged to Construction	498	-	2	500	77	285	13	875
Total Installed Cost	1,792	-	8	1,800	319	1,860	60	4,039
Foreign Exchange	1,048	-	5	1,053	176	590	18	1,837
Total for Period 1966-1985								
Cost (less Duties, Taxes and Interest)	3,737	252	138	4,127	1,499	5,250	132	11,008
Duties, Taxes and Interest Charged to Construction	1,490	34	54	1,578	501	1,090	39	3,208
Total Installed Cost	5,227	286	192	5,705	2,000	6,340	171	14,216
Foreign Exchange	3,054	210	111	3,375	996	2,380	54	6,805
% of Total Installed Cost								
1966-1970				40.5	19.6	39.1	0.8	100
1971-1975				29.5	15.1	54.4	1.0	100
1976-1980				45.0	15.4	38.3	1.3	100
1981-1985				44.6	7.9	46.0	1.5	100
1966-1985				40.1	14.1	44.6	1.2	100

a/ Includes "Total Installed Cost" of PRs 114.8 million for completing Mangla 1,2 & 3 which is part of the Indus Basin Development Fund Agreement.

XI. CONCLUSIONS

11.01 The main features of the power program proposed in this volume are: the completion of the Tarbela Dam in 1975 so that its substantial hydropower potential can be progressively realized in the following years; concentration of thermal development in the vicinity of the Mari-Sui gas fields to use the gas there for the production of supplementary power during the critical low water periods on the hydro plants and semi-peak power at other times as required by the Provincial system; installation of 380-kv interconnection starting with a line between Mari and Lyallpur in 1971 and as soon as feasible embracing all main load centers -- at latest by the time that Tarbela comes on line; and a continuation of thermal development based on Sui gas in Karachi.

11.02 Tarbela and interconnection represent the two most significant blocks of investment proposed for the power sector of West Pakistan over the next 20 years. It is only by reference to them that the validity of other proposed system developments is assessed. This applies even to additions to the system made before either interconnection or Tarbela would be completed because most of the economic life of such additions would take place during the time that Tarbela and the EHV transmission network dominate the system.

Load Forecasting and System Planning

11.03 The program is, of course, designed to meet a specific load forecast. Such a load forecast is particularly crucial to the study because of the size of the Tarbela Project. Tarbela is of an entirely different order of magnitude from any other generating plant ever constructed in West Pakistan. Its installed capacity of 2,100 mw would be more than twice the capacity of all existing generating equipment in the Province and more than four times the 1965 peak load on the largest of the existing power systems. In addition, since the dam will not be completed for eight or nine years the earliest load of relevance is that of 1975. Moreover, since under any foreseeable circumstances, the load of the Province will not be sufficient at that time to absorb the whole of Tarbela's contribution to power supplies, the growth of the load in the years following 1975 will be of critical importance. It will determine how quickly it is worth installing the power units at the dam and when it is economic to link the different power markets together by a transmission system capable of carrying large quantities of electricity. For these reasons the load forecast that was needed for evaluation of Tarbela not only had to cover at least 20 years, but also had to include considerable detail on the regional distribution of the load.

11.04 The forecast of power requirements as prepared by the Bank Group's power consultant, Stone & Webster, with adjustments to include IACA's final estimate of agricultural pumping demand, envisages that energy generation by public utilities would increase at an average annual rate of about 11 percent, from approximately 3,400 million kwh in 1965 to 28,400 million kwh in 1985. The Bank Group has concluded

that this projection is of the right order of magnitude and provides an appropriate basis for power system planning. Stone & Webster's prediction as to regional distribution of the load between the North and the South also appears reasonable but, as they suggested, would need to be frequently reviewed and revised to meet changing conditions. For planning purposes, the Bank Group also prepared a somewhat higher contingency forecast for the Northern Grid which was used to test the sensitivity to load change of some of the Bank Group's key recommendations such as those relating to the timing of transmission installation.

11.05 On the basis of its review the Bank Group feels that load forecasting and system planning in West Pakistan need to be done to a greater extent than in the past in a systematic way on a Province-wide basis and in closer coordination with general economic planning. Use of a system simulation model similar to that presented in this report would help considerably in the expeditions adjust ent of power system expansion plans that will be necessary as load forecasts and other basic data change. For effective planning of system development, the responsible authorities must have both a continuous flow of up-to-date information on expected power requirements and a thorough analysis of the many possible alternative ways of meeting the demand. Therefore, it is important that both WAPDA's system planning staff as well as its load forecasting section be strengthened and that there be much greater coordination between WAPDA and KESC in Province-wide forecasting and system planning in the future, especially in view of the prospect of the interconnection between the North and South in the early 1970's. Short-term forecasts should be kept under constant review and revised annually; long-term forecasts should be reviewed in relation to economic trends and major industrial developments.

Power Program During the Third Plan Period

11.06 System developments of the next three to four years are largely predetermined by this time. In recent months, both the Northern Grid area and Hyderabad have been suffering from severe power shortages. These shortages should be eliminated within the next few months. Existing commitments of WAPDA, including installation of the first four units at Mangla (each with a maximum capacity in August of 135 mw), construction of 100-mw thermal capacity at Mari-Sui and completion of the 132-kv link between Rahimyar Khan and Mari-Sui should be sufficient to meet loads on the Northern Grid in 1970. However, near-term peak loads in the Northern Grid are presently hard to predict because of the current uncertainty about the extent of both load shedding and unsatisfied demand. By 1968 WAPDA should be able to meet demand in full and actual sales will then begin to provide a better indication of what the existing load in the North really is and how it is likely to grow. With the planned expansion of the Korangi station, Karachi should continue to have sufficient capacity.

11.07 Thus, if the program now underway is executed as scheduled, West Pakistan would be able to meet the load forecast in this report

for the Third Plan period. However, the margin of reserve for 1970 is not adequate as indicated in the table below unless the proposed transmission program is also carried out as scheduled. It is noteworthy that by 1969, as much as 90 percent of the electric energy required by the large Northern Grid area would be supplied by hydro stations.

Table 88

Generating Capability and Peak Loads, 1970
(Megawatts)

		Capability	Peak Loads Forecast	Peak Loads Contingency Forecast
Without 132-kv Transmission Link				
Northern Grid	(March) a/	830	813	879
Upper Sind	(October)	250	45	
Lower Sind	(October)	84	73	
Karachi	(October)	375	309	
With 132-kv Transmission Link				
North/Upper Sind	(March) a/	1,080	852	918
Karachi/Lower Sind	(October)	459	382	

a/ Minimum capacity at hydro stations.

Power Program During the Fourth Plan Period

11.08 For the Fourth Plan period, the Bank Group concluded that it will be necessary to install 400 mw of thermal capacity at Mari-Sui as well as four more units at Mangla (units 5-8) and the 125-mw nuclear plant at Karachi (now under construction) besides the 380-kv Mari-Lyallpur and Mari-Karachi transmission links. These facilities seem adequate to meet likely load growth in both the North and Karachi with adequate reserve, but it would require very careful rechecking in 1968/69. Reassessment in 1968/69 may show that a small amount of additional generating capacity beyond that included in the Bank's program will be required to meet loads in 1972/73. If Mari-Karachi 380-kv intertie is completed in the early 1970's as is proposed in the program, the Bank Group believes that enough of the energy from Mangla units 7 and 8 could be absorbed in the South to make it worthwhile to install them before Tarbela comes on the line in 1975. A serious delay in the completion of the Mari-Karachi interconnection, however, would necessitate changes in the program and might make it preferable to postpone adding units 7 and 8 at Mangla until the demand has grown sufficiently in the North to absorb the additional energy.

11.09 Thus the Bank Group firmly believes that an EHV transmission line should be constructed at an early date to interconnect the North, the gas fields and the Karachi area. This would serve to make the greatest use of Mangla, Tarbela and other hydro facilities in the North and the natural gas resources available at the Mari and Sui gas fields,

and to minimize the fuel costs of supplying the Karachi area. The initial EHV transmission line should be constructed between the Mari or the Sui gas field and the Northern Grid, if possible by 1971, to provide the North with thermal capacity in the low water season prior to the completion of Tarbela. In any case the connection between the gas field and the Karachi area should be completed at least by 1975 to permit the transmission of surplus Tarbela energy from the North to the Karachi market.

11.10 Another crucial Fourth Plan period decision relates to the use of gas for power generation. The existing pipeline from the Sui gas field to the South should, in the opinion of the Bank Group, be expanded in the near future to take care of the demands for gas in that area prior to the interconnection in 1971-72 as peak demands there could better be met with gas than with fuel oil. A delay in completing the interconnection between Mari and Karachi would involve heavy reliance on fuel oil for power generation if the gas pipeline were not expanded in the meantime. If the Northern and Southern systems are interconnected by 1971 or 1972 further expansion of the gas pipelines to supply fuel for power generation in these markets will be unnecessary after 1972. If, however, a moderately large gas field were developed at Sari Sing near Karachi or further gas discoveries were made in the North, this situation would change. If the Sari Sing field proves large enough, it might supply Karachi with gas at times of peak demand and it might also be used for storage after its own supply is diminished somewhat.

11.11 The type of gas-burning power units will also be an issue of some importance during this period. The Bank Group believes that because of the low load factors that may be expected on the thermal units at the Mari-Sui gas fields, it would seem advisable that a good proportion of the installations at Gudu should be in the form of gas turbines.

11.12 By 1975, if the recommended program were carried out, an interconnected system would be created with a total capacity of 2,323 mw to meet a projected demand of 2,097 mw. The table below shows the capacity increases in the three main areas as well as total demand for 1975 and for an intermediate year, 1971. For comparison, the program through 1985 is also included.

Table 89

Development of Major Parts of West Pakistan's Power System According to the Bank Group's Program

(Megawatts)

Years	Northern Grid	Upper Sind	Hyderabad Karachi	System Capacity	System Demand
1971	910 a/	250	510	1670 a/	1405
1975	1180 a/	450	720	2350 a/	2097
1980	2026 b/	650	920	3596 b/	3165
1985	2026 b/	1350	2020	5396 b/	4864

a/ In March.
b/ In May.

Power Program During the Fifth Plan Period

11.13 The most significant additions to the system during the Fifth Plan period would be at Tarbela. The first eight units are to be installed with a rated capacity of 1,400 mw. Two additional units are proposed for Warsak with a capacity of 80 mw which will assist in carrying the load during May, the critical month of the year. The installation of 200 mw of steam capacity at Mari-Sui and 325 mw at Karachi are also scheduled as it appears that the best source of thermal generation in the late 1970's would be natural gas. At the end of the period the total system capacity would be about 3,596 mw to meet a peak demand of 3,165 mw.

Power Program During the Sixth Plan Period

11.14 The Sixth Plan program focuses on the central fact that by the early 1980's the potential at Tarbela will have been largely utilized when the last four Tarbela units will have been installed. The need for substantial additions to generating capacity of the order of 700 mw in the North and 1,000 mw in the South is expected. The amount of gas reserves remaining at the time will be the determining factor in deciding what the best source of fuel for thermal generation will be. The Bank Group's analysis indicated that, on the basis of information currently available, it would appear sound to install 700 mw of additional steam units at Mari-Sui, and 1,100 mw at Karachi, 800 mw of which might well be nuclear.

Tarbela and Beyond

11.15 The substantial role of Tarbela in the Bank Group's recommended power program stands out in the program set forth. Because of this fact it was important that the Bank Group reassess the power benefits expected from the Tarbela Project. Stone & Webster calculated the investment and operating costs that would be required, over the next fifty years in a power system including Tarbela and in an alternative system in which thermal and other hydro capacity would be substituted for Tarbela. The difference between the discounted present-worth cost of the system including Tarbela and that of the alternative amounted to $80 million. This figure was incorporated by Stone & Webster in their 1965 report as the net power benefits of Tarbela. However, the Bank Group found that the power benefits attributable to Tarbela are very sensitive to changes in the assumptions regarding the price of fuel. Using a range of fuel prices, the Bank Group found that a power system including Tarbela from 1975 onwards would be substantially cheaper in terms of present worth than the cheapest alternative at all fuel prices above 20 cents per million Btu. If due weight is given to the probable increase in the scarcity value of fuel over time as the indigenous reserves are gradually exhausted, then the net power benefits of

Tarbela on a present-worth basis would be about $150 million. Moreover, the Bank Group calculated that the total cost to the economy of West Pakistan if Tarbela were delayed to 1985 would be substantial, around $103 million (using the current rate of exchange) in terms of present worth and $48 million (using a shadow rate of exchange). The completion of Tarbela in 1975 is a critical factor in the development program recommended by the Bank Group.

11.16 After Tarbela is completed a number of important decisions will have to be made. They include those relating to the expansion of the EHV transmission system, the scheduling of units at Tarbela, the drawdown levels for operating Tarbela and Mangla and the type and location of thermal capability to be provided to firm up the hydroelectric units and help stabilize the transmission system.

11.17 The first issue has been referred to in paragraph 11.09 above. The further expansion of the 380-kv transmission system is proposed mainly for interconnecting Tarbela and Lyallpur and the addition of further links between Lyallpur and Mari to enable the transfer of larger quantities of hydropower to the South.

11.18 As to the installation of generating units at Tarbela, assuming EHV interconnection between the North and South and thermal units at the Mari-Sui gas fields, the Bank Group's studies indicate that a somewhat more rapid installation of the Tarbela units than suggested by Stone & Webster is desirable. Instead of installing 8 units by 1978 and postponing the last 4 until 1982/83, the Bank Group's analysis shows that it would probably be more advantageous to bring in the first 4 units in 1975/76 and the remaining 8 units between 1978 and 1980.

11.19 The Bank Group noted that the maintenance of higher or lower drawdown levels at Mangla and Tarbela will have a significant effect upon the amount of complementary thermal capability required to meet peak loads in the critical months in the Spring. Raising the head on the Mangla turbines by increasing the minimum reservoir level from 1040 feet to 1075 feet would increase capability by 140 mw at the loss of 400,000 acre-feet of potential rabi irrigation supplies. Similarly, raising the level from 1300 feet to 1332 feet on Tarbela at the sacrifice of 700,000 acre-feet would add 270 mw of capability. For analytical purposes the Bank Group focused attention on the two alternatives at Mangla of 1040 feet and 1075 feet and the two at Tarbela of 1300 feet and 1332 feet in order to secure an indication of the relative priority that should be attached to the needs of agriculture and power in the use of marginal amounts of stored water.

11.20 In the opinion of the Bank Group, it would be advantageous, at least until 1975, to draw down the Mangla Reservoir to elevation 1040 feet rather than 1075 feet, as suggested by Stone & Webster, because it appears that the benefits to agriculture in this period would exceed those to power. Between 1975 and 1985, however, the

marginal value of additional irrigation water will decline once Tarbela and a large number of public tubewells are completed and it may become advantageous to maintain the reservoir at a level of 1075 feet in some years and thus increase the benefits to power.

11.21 If the first units at Tarbela cannot be installed before the critical low water period in 1975 it would probably be beneficial to keep the Mangla Reservoir at a level of 1075 feet in that year, to avoid the necessity of load shedding or the addition of thermal capacity which would be relatively little used for the following few years. Rabi irrigation supplies should be reasonably ample in 1974/75 because under the present construction schedule Tarbela would be filled to about 5 MAF on the receding flood flows of 1974.

11.22 According to the Bank Group's calculations, the present-worth benefits to power and to agriculture of the alternative allocation of marginal quantities of Tarbela storage capacity suggest that the Tarbela Reservoir should be operated, at least over the period 1975-85, to the higher level of 1332 feet rather than the lower drawdown level of 1300 feet.

11.23 The decisions regarding the drawdown levels at Mangla and Tarbela should not in practice be firmly set for any lengthy period but the reservoirs should be operated in such a manner as to take advantage of the flexibility which these large projects will provide for both power and agriculture. In the infrequent critical low water periods it would be preferable to shed load for a few hours each day rather than make substantial investments to provide for additional reserve capacity.

11.24 The Bank Group's studies showed that conventional thermal plants based on natural gas plus the large hydro facilities at Mangla and Tarbela will largely satisfy power needs until around 1980. Thereafter other facilities will be needed and for this reason the Bank Group carried out limited investigations of the possibilities of coal-based thermal plants, nuclear energy and other hydropower projects.

Alternative Generating Facilities

11.25 The studies indicate that with the probable increase in the value of natural gas as the supply diminishes and it becomes scarce, a coal-fired generating plant using Lakhra coal might be worth considering in the late 1970's. For coal to be competitive with natural gas, however, it would have to be produced at a cost somewhat less per Btu than natural gas because of the higher capital and maintenance costs of coal-fired stations. It is unlikely that the value of gas in the late 1970's will be over 34 cents per million Btu. Consequently, to be competitive, coal would have to be delivered at a price of PRs 20 per ton which appears at the present to be unlikely; moreover, in the early 1980's a coal-fired plant would probably also face competition by southern nuclear plants.

11.26 Despite foreign exchange difficulties, the Bank Group believes there will probably be a strong case for extensive development of nuclear power in the South in the early 1980's. Loads there should be adequate at that time to provide a 400-mw nuclear plant with a load factor of over 80 percent and by 1985 to provide a second 400-mw unit with a load factor of nearly 70 percent. Low load factors on the thermal plants in the North would probably continue to make nuclear plants there uneconomic.

11.27 The raising of Mangla Dam for power generation does not appear to have economic advantages as a potential hydro project before 1985. The main consideration working against the raising of Mangla before 1985 is the fact that a sizeable part of the energy and capacity which it would add would occur in the summer flood months when Tarbela would be producing more energy than could be absorbed.

11.28 The proposed hydroelectric project on the Kunhar River, with a firm capacity of about 500 mw was not considered to be an economic alternative to a similar amount of thermal development based on gas to serve the Northern Grid in the early 1980's. The Bank Group's calculations show that, with Tarbela and Mangla in operation, the break-even point for Kunhar compared with thermal plants fired with gas would be at a gas price of 58 cents per million Btu at current exchange rates and 90 cents per million Btu at the higher exchange rates assumed. (Rs. 9.52 = $1). The Kunhar Project might become justifiable in the late 1980's or early 1990's.

Other Issues Considered

11.29 The Bank Group presented a number of other issues in the report, such as electric distribution, tariffs and organization, which are particularly important.

Distribution

11.30 Deficiencies in the distribution system make it urgent that WAPDA take the necessary steps to provide and train adequate manpower for work in this field during the next five years. Sufficient funds must also be allocated for the renovation and expansion of the distribution networks -- otherwise substantial amounts of the generation from new installations cannot be sold.

11.31 Particular effort is needed to expedite the distribution work in connection with the public tubewell projects. Because of the large program envisaged in the next decade, procedures for planning distribution systems, awarding contracts and ensuring prompt connection of the wells after completion must be streamlined. An adequate inventory of distribution equipment should be maintained to support a sustained construction program and an effective inventory control system should be established. Financial needs of the program should be anticipated well in advance so that allocations of sufficient foreign and local exchange can be scheduled in accordance with construction requirements.

Tariffs

11.32 Because of the low tariffs for tubewell pumping, farmers are now subsidized by the urban consumers. With increasing demands for pumping, WAPDA and the Government of Pakistan should consider either raising the tariffs for pumping to a break-even point or providing WAPDA with enough budgeting funds to cover the subsidy to the farmers, should this be the Government's policy. In any event, WAPDA's tariffs should be maintained at a level which would produce revenues sufficient to provide at least an 8 percent return on net fixed assets in operation. WAPDA's needs for local currency for expansion are great and with adequate tariffs WAPDA could supply a substantial portion of these needs and thus relieve the burden on the Government budget.

11.33 The Bank Group recommends that KESC's tariffs should be revised in accordance with recommendations of its consultants so as to simplify them and to eliminate inequities and should be maintained at a level to provide KESC with adequate local currency for its expansion program. In no event should KESC's tariffs provide a return of less than 8 percent on net fixed assets in operation. If KESC is to continue to pay dividends and continue to expand its facilities its local currency requirements will be such that, with existing tariffs, its efficiency must be of a high order.

Organization

11.34 WAPDA's Power Wing should be strengthened to increase its efficiency but it is not recommended that any of its functions be transferred to a new organization at the present time; among functions of the Power Wing which in particular should be strengthened are its billing and collecting procedures. In addition, it should concentrate on reduction of losses and diversions of electricity by illegal means. With the advent of interconnection by EHV transmission, a suitably staffed dispatching station will be required. It will be essential to have a Chief Dispatcher with authority to order the assignment of load to specific generating stations and to direct the flow of energy efficiently from generation stations to market areas through the control of high voltage transmission lines.

Financial Requirements

11.35 Finally, the Bank Group believes that the current allotment for power in the Third Five Year Plan amounting to PRs 2,420 million is inadequate to carry out its recommended program for this period, estimated to cost slightly over PRs 3,000 million. Furthermore, the cost of the program is expected to increase to about PRs 3,480 million during the Fourth Plan period, PRs 3,680 million and PRs 4,040 million for the two Plan periods that follow. Although the Bank Group believes that total expenditures for its recommended program for the 20-year period 1966-85 should be considered only as an order of magnitude, the figures probably represent minimum estimates of what will be required if an adequate power program is to be carried out.