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

Annexes 1 - 11

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July 28, 1967

LIST OF ANNEXES

NOTE: A detailed table of contents of each of the above annexes may be found preceding the relevant text. This does not apply to Annex 10 which is bound separately. Moreover, a complete table of contents of all the annexes may be found in the volume containing the main report of Volume IV.

ANNEX 1

LOAD FORECASTING

LOAD FORECASTING

Table of Contents

Table of Contents (continued)

LOAD FORECASTING

The Role of the Load Forecast

Establishing a reasonable projection of future demand for the stream of goods that will be produced as a result of investment of capital in a project is always an important part of project evaluation. There are a number of reasons why it is particularly important in the electric power sector. First, power projects tend to have exceptionally long lead times; Tarbela, which is expected to take about eight years to build, is somewhat unusual but even gas turbines require two-three years' lead time when the delays involved in securing clearance at different levels of government and obtaining external financing are taken into account as well as the time required for design, bidding, letting contracts, land acquisition, construction, final testing, etc. In the power sector, there is little possibility of responding quickly to a favorable market situation, indicated by shortages and rising prices, with a quick switch of resources or construction of a small plant, as there is in many other sectors of the economy. Secondly, mistakes in forecasting power loads -- and international experience shows that they are all too frequent -- tend to be expensive. Partly this is related to the first point; generation and distribution of power to consumers require heavy capital investments which take a relatively long time to execute. Investments in power facilities represent a sizable part of a country's total investment. In West Pakistan, for instance, power supplies were short throughout the Second Plan period and a serious power crisis developed soon after completion of the Plan period; nevertheless the public share alone of total investment in power facilities was 15 percent of public investment and 6 percent of total investment in the Province during the Plan period. Over investment in power can thus mean a waste of capital of significant proportions. But the losses that result from under investment equally tend to be large. Because power is consumed in relatively small quantities by very large numbers of consumers the effects of power shortages tend to be widely felt. Once equipment driven by electric power has been installed, there is generally little possibility of substituting electricity with some other source of energy. Moreover, the brunt of any power shortage has generally to be borne by those using power for production purposes in agriculture or industry rather than by domestic or commercial consumers -- partly because the industrial and agricultural loads tend to occur in larger blocks which can be more easily controlled, partly because of the technical, social and political difficulties of shedding urban residential and commercial loads. Power shortages therefore tend to have serious effects on the output of other productive sectors of the economy and to cause hesitation on the part of potential investors, thus curtailing economic growth.

From the economic point of view the evaluation and justification of power projects are rather hard to handle. Electric power is neither clearly substitutable nor, despite what was said in the previous paragraph, clearly indispensable. Before consumers have committed themselves

to equipment driven by electricity they may face a choice between such equipment and alternatives driven by other forms of energy. But the extent of choice varies widely in different fields of consumption; machinery powered by natural gas is a reasonable alternative in some fields in West Pakistan such as domestic heating and air-conditioning and kiln firing, but in many other fields, such as lighting and much technical production equipment, adequate substitutes do not exist. For this reason, because of the prior commitment to equipment using only one type of energy that is generally unavoidable, and because of the great economies of scale involved in production of electric power, electricity does not sell in a free market which sets a price for it in competition with other forms of energy. It is rather sold at administered prices which give little indication of what people would be prepared to pay for it. Hence the benefits of an electric power project cannot reasonably be evaluated in the way that the benefits of many capital investments can be computed, by projecting a stream of output, multiplying the physical outputs by projected prices and subtracting current costs for labor, materials, etc. But because electric power is not clearly indispensable any more than it is substitutable, the other widely-used technique of projecting benefits -- estimating values for output at one remove from the market -- is also not relevant. The value of irrigation water, for instance, can often be reasonably projected by attributing to it the entire difference between the market value of the agricultural production which it makes possible and the market value of other inputs -- fertilizer, seed, etc. -- used in the production process. Publicly generated electric energy is not as clearly indispensable as irrigation water, nor is it nearly such an important input in most production processes as irrigation water is in agriculture.

Since these customary means of benefit evaluation are inappropriate to power projects resort has been had in this Report to a technique which is often used in the utility field and which 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 "net benefits" of a power project are defined as the difference between the cost of meeting the load with the project in question and the cost of meeting it with the "cheapest alternative" project. The calculations are almost entirely internal to the power sector once the load forecast has been made. Everything depends on the load forecast -- it bears a dual responsibility, serving for both the physical demand projection and the price projection that can be made for most commodities. If the load forecast is too high relative to growth of 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; large projects may be undertaken before they are warranted. If it is too low, on the other hand, then serious disruption may result in the rest of the economy and economic growth may be curtailed, as it has been by the recent shortage of power in West Pakistan.

Thus the load forecast is the crucial link between the power sector and the rest of the economy and between planning for each. One of the main tasks of this report was to reassess the benefits of the Tarbela project. Another important task was to identify the other generating and transmission investments that should be made over the Perspective Plan period and particularly over the next decade or so, given the fact that Tarbela Dam would be completed by about 1975. Justification of Tarbela and selection of an appropriate mix of supporting projects depend intimately on the load forecast, and it was important therefore to see that the load forecast used was consistent with the other plans and proposals coming out of the Indus Special Study. There were other reasons too why the relationship between the load forecast and general economic growth projections for West Pakistan was considered important. In the first place there is wide agreement that, because of the crucial nature of the load forecast in planning the internal development of the power sector and in deciding appropriate patterns for allocation of government investment funds among sectors, load forecasting in West Pakistan needs to be much more closely linked with economic planning than it is at present. In the second place, one of the purposes of the Indus Special Study was to make a contribution to the serious effort at long-term planning that is underway in Pakistan by going into depth in the agriculture and power sectors and trying to assess the attainability of targets and to identify the specific bottlenecks that might arise, the resources that would be needed for meeting projected demands, etc. To be useful for this purpose the load forecast needed to be cast in a framework compatible with planning categories used in the general planning effort.

The Time Span of the Load Forecast

Load forecasts covering various numbers of years are useful for various different purposes, but the time span of the load forecast required for these studies was set mainly by the long time required to build and then to absorb fully the power from Tarbela. Rather specific short term (2-3 year) load forecasts are needed in the operation of a power system for formulating maintenance programs, building up fuel stocks at thermal stations and planning seasonal power exchanges. For purposes of planning additions to generation and transmission capacity a longer-term forecast is needed. Insofar as two to four years generally elapse between a definite decision to add thermal capacity and completion of installation, a five-year load forecast may be adequate to ensure the sheer availability of capacity to meet loads. But to enable a correct decision to be taken as to the type and size of generator required and to ensure its most economic integration into the system a longer load forecast -- for about a 10-year period -- is the minimum required. When a substantial hydro development is envisaged these arguments are reinforced and an even longer perspective is required to decide how the plant compares with other potential projects, when it should be installed and how it will affect the intermediate development of the system. Both Mangla and Tarbela, for instance, have minimum capabilities at full development comparable with the present peak

on the Northern Grid of about 500 mw. 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. To handle these questions a 20-year period was adopted for the load forecast. Because views about the answers to these questions affect matters requiring early decision, such as dam design, transmission line investment and the intermediate installation of thermal capacity, so too a 20-year load forecast has considerable relevance for the present. The fact that long-distance transmission of power is an important subject in West Pakistan, requiring some early decisions about large investments in high-tension lines, means also that reasonable estimates are needed of the future regional distribution of power loads in different parts of the Province.

WAPDA Load Forecasting

One way of making a long-term load forecast for West Pakistan would be to use the short-range forecasts prepared by WAPDA in recent years and then to extrapolate them in one way or another. The first comprehensive survey of the power market in West Pakistan, outside of Karachi, was carried out by Harza Engineering Company under the auspices of WAPDA in 1961/62. The survey, results of which were published in a report entitled Power Market Survey and Forecast of System Loads (June 1963), 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 11 Civil Divisions outside Karachi and they were then reassembled on a load center basis. Many of the procedures now used by WAPDA for load forecasting were originally established during the course of this survey.

WAPDA set up its own Power Market Survey Organization 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 seven main classifications: residential and commercial, small industry (less than 70 kw connected load), medium and large industry, agriculture, SCARPs (Government Salinity Control and Reclamation 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.

Small industrial loads are grouped with residential and commercial loads. Statistics on energy consumption by these classes of customer are available from WAPDA's regional revenue and subdivisional offices. Predetermined load factors ranging from 10 percent to 30 percent, higher for the wealthier and larger towns, are assigned to

estimate peaks. Prospective small industrial loads are assessed on the basis of the installed capacity of existing prime movers used and energy calculated on the basis of an assumed load factor. The residential and commercial load of areas to be electrified in forthcoming years is estimated on the basis of graphs, originally prepared by Harza, showing some correlation between per capita usage of energy and size of settlement for different types of areas. Four of these so-called "Electric Use Potential" graphs are used and the load of a village which is to be electrified is read from the graph considered relevant to a place of its economic standing. Potential residential and commercial use is increased at three percent per annum for the years preceding electrification. All existing commercial and residential loads are raised by eight percent, as an allowance for required voltage improvement, and then projected along with small industrial loads at a flat rate of six percent per annum.

Agricultural loads (both public and private, except for SCARPs) are grouped with medium and large industrial loads as being the larger individual loads. The Harza survey included interviews with tubewell owners. Information on agricultural sales is available at the subdivisional and regional revenue offices of WAPDA. Utilization factors of 25 percent are applied to private tubewells and 65 percent for public tubewells. An allowance is made for new tubewell connections on the basis of the capacity of the existing prime mover. Medium and large industries are visited by the Power Market Survey Organization and their existing peak demands, as well as total energy requirements, are relatively easily obtainable since WAPDA has installed demand meters for these consumers. Maximum load achieved on their own (industrially owned) generating equipment is used to indicate the probable demands of existing industries which are to be connected to the WAPDA system. Information about likely new industrial loads is obtained primarily from the various Government sanctioning agencies for industrial projects; it is checked with the industrialists in the field, but it is not clear how much judgment 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 are also increased at a rate of about six percent per annum.

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 are then added, including their own somewhat lower allowance for losses and a further seven percent allowance is added for transmission losses. Further diversity factors are applied to bring loads up to the total estimated for each grid system (North, Upper Sind, Lower Sind, Quetta).

As regards Karachi, WAPDA has made no independent load forecasts there, but Karachi Electric Supply Corporation has been making short-term forecasts for a number of years, based mainly on negotiations

with industrialists regarding prospective industrial loads and simple projections of the total residential/commercial load. Their forecasts use a somewhat larger number of categories than the WAPDA forecasts. A thorough survey of the Karachi power market was undertaken in 1963 by Zafar and Associates, a local consulting firm, in association with Laramore, Douglass and Popham of New York.

Since the load forecasts made by the utilities in West Pakistan are all relatively short term (not more than 10 years and, for WAPDA, generally only five years) it would be necessary to make some extrapolation in order to reach a load forecast of adequate dimensions for the purpose in hand. Such an extrapolation would be difficult. The classifications of load are so aggregated (besides being different between Karachi and the WAPDA system) that it would not be possible to link them with any of the categories used by the Planning Commission in its projections for West Pakistan. Experience of other countries is often a useful guide for load forecasts, but again the aggregation of such diverse categories in the WAPDA projections would make it very hard to make projections on this basis. About the only practicable basis for extrapolation would be the overall growth rate of electric energy requirements encountered in different countries. However, overall growth rates are the outcome of so many diverse forces operating in each country, many of them peculiar to the country in question, that it is difficult to infer anything very meaningful on such a global basis. Moreover, as Table 1 suggests, the experience of different countries is so varied -- and the overall growth statistic gives no indication as to the causes accounting for the variation -- that it is possible to prove almost anything on such a basis.

Table 1

Average Annual Growth Rates in Electricity Production, 1955-64
(Percent per annum)

Africa		Europe	
S. Africa	7.8	Austria	7.3
		Denmark	7.5
North America and Caribbean		Finland	8.0
Canada	5.5	France	7.3
Dominican Republic	11.3	West Germany	8.6
Guatemala	6.8	Iceland	5.8
Jamaica	20.0	Ireland	8.2
Mexico	9.4	Italy	8.1
Nicaragua	10.9	Netherlands	8.3
USA	6.2	Norway	7.0
		Portugal	10.8
Oceania		Romania	13.7
Australia	4.6	Sweden	6.4
		Switzerland	16.0
		United Kingdom	7.7
		Yugoslavia	14.1

/Continued

Asia		South America	
Ceylon	10.2	Argentina	9.7
India	13.0	Bolivia	10.7
Israel	12.5	Brazil	9.3
Japan	11.9	Chile	3.9
Pakistan	16.7	Peru	10.7
Philippines	14.6	Uruguay	6.0
Turkey	12.1		

Stone & Webster Forecasting Methods

Rather than adopt an approach of this nature Stone & Webster tried to develop load classifications which, within the limits of available sales records, had a firm historical base and were at the same time potentially compatible with the categories used in economic planning. In their classification of loads they also tried to distinguish between those with different technical characteristics (load factors, monthly distribution, time of day when peak occurs, etc.) so that the effects of different rates of growth in the various classes and of any likely changes in these technical characteristics on the shape of the overall system load curves could be identified. Stone & Webster used hypothetical 1965 figures as the basis for their load forecast rather than the actual sales figures for 1960-64 which were available to them because of the downward bias imparted to the actual figures by the load shedding and voltage reduction which took place in those years. In their 1965 base they also included small allowances for the loads which were at that time met by small independent utilities within the WAPDA service areas but which in future will be largely met by WAPDA.

Stone & Webster made forecasts of energy requirements in each of the four main electrical zones of West Pakistan (Northern Grid, Upper Sind, Lower Sind and Karachi) by class of service -- residential, commercial, agricultural (public and private), industrial, public lighting, bulk and losses -- for the key years 1970, 1975, 1980 and 1985. Annual hours of use were then assigned to each class of consumption in order to derive the peak demand of each class. Class demands were then totalled and a diversity factor was applied in order to obtain total area demand. Monthly energy requirements and peak loads were derived for the key years on the basis of the existing pattern of demand over the year and with attention to likely changes in the pattern resulting from the growth of tubewell load, gradually 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 for each month of the 20-year planning period. In all his calculations, the power consultant used loads net of station use, because station use differs so much between thermal plants (about five percent of capacity) and hydro plants (about 0.5 percent of capacity) that use of gross demands could lead to exaggeration in later years when the system is more heavily hydro based.

For the forecast of industrial loads Stone & Webster made use of the WAPDA and KESC files on existing industrial loads in the various areas and on sanctioned industries. Stone & Webster codified this material and evaluated it, making some allowances for delays in project execution where these seemed likely. For the longer term Stone & Webster had to be guided by the macroeconomic framework for the growth of West Pakistan provided by the Perspective Planning Section of the Planning Commission -- which assumes a rather sharp falloff in the industrial growth rate -- and by their own evaluation of the resource base and industrial climate of the different regions of West Pakistan.

The basis for Stone & Webster's residential load forecast was the 1960 Housing Census and a number of socioeconomic surveys of the major cities of West Pakistan and of some rural areas in the North. They adopted the housing unit (i.e. independent household -- defined as a family or group of persons living together and eating from the same kitchen) as the basic building block of the residential load forecast. The number of housing units in existence in different areas in 1965 was projected on the basis of the 1960 Housing Census and the 1961 Population Census, differentiating between those in towns of more than 25,000 population[1/] and those elsewhere. The proportion of houses currently connected in each area was estimated on the basis of the socioeconomic surveys and any other information available, as well as independent field checks. Stone & Webster assessed consumption per house on the basis of estimated residential sales of energy in 1965. From the base year of 1965, they proceeded in the same manner, estimating the number of houses there would be in each of the key years 1970, 1975, 1980 and 1985, on the basis of population projections for those years, and then estimating the proportion of houses that might be expected to be electrified by each key year. The gradual growth of electricity consumption per house was also assessed on the basis of estimated use in 1965. Multiplication of the number of electrified houses in each area by the projected average annual consumption per house gave a figure for total domestic consumption in each area in each key year.

The basic material on the agricultural loads was prepared by the Irrigation and Agriculture Consultant (IACA) on the basis of 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; for areas not covered by the public tubewell program they projected continuation of private tubewell development and a gradual increase in the proportion of private tubewells electrified. 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 diversity factors to be applied in the aggregation of tubewell loads in an area. In order to reduce the system peak at critical times an allowance was

1/ According to the 1961 Population Census.

made for interrupting tubewells during the four hour evening peak period. IACA revised its pumping projections substantially between the time that Stone & Webster submitted their report and completion of the Study; Stone & Webster prepared a revised pumping load forecast. The projections of tubewell load, which were made on a monthly basis, are discussed in greater detail in Appendices I and II to this Annex.

There are certain other existing and prospective loads which are either discrete items which Stone & Webster projected as such or classes which make up relatively small portions of the total load such as Public Lighting. Examples of the first are construction power for Mangla and Tarbela Dams, railway electrification and the load of the Wah Ordnance Factory. For public lighting Stone & Webster applied a rate of growth somewhat above that experienced in developed countries.

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 15 percent of total energy generated in 1960 to a peak of about 22.5 percent in 1962. In 1964 they amounted to about 20 percent of energy generated. The power consultant estimates that part of these losses -- mainly due to the bad state of the distribution system 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, he estimates that losses 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 11 percent on the KESC system, but it does of course have the advantage of being much more compact.

Bank Group's Review of Stone & Webster Forecasts

The load forecasts which Stone & Webster reached by application of these methods are described fully in Chapter IV of this Volume IV. The Bank Group reviewed both the methodology and the results in considerable detail and found that they were generally good. Many assumptions had had to be made, but that was inevitable given the uncertainty of basic data and the absence of any detailed projections for the growth of the non-agricultural sectors of the economy. The classification used by Stone & Webster seemed appropriate, and the effort that they had made to develop forecasts of monthly loads on a common basis for the whole Province seemed to be a useful contribution to the process of load forecasting in West Pakistan.

In reviewing the projected loads finally adopted by Stone & Webster, the Bank Group had in mind that a long-term forecast should, if anything, err on the optimistic rather than the pessimistic side so as to make sure that plans are made sufficiently far in advance to cope with the loads when they come. The Bank Group came to the conclusion that the Stone & Webster load forecast generally met this criterion. The

order of magnitude seemed reasonable. Studies undertaken by the Bank Group[1] attempting to link the load forecast to long-term economic development in West Pakistan suggested that the residential load projected by Stone & Webster might be slightly too great (because of the rapid rate of increase in consumption per household assumed) and also that the growth rate of industrial load adopted by Stone & Webster might be a little too high around the middle of the Perspective Plan period and a little too low at the end of the period. This meant that the forecast tended to the optimistic side. In addition to reviewing each of the various classes of load the Bank Group also tried, as best it could, to evaluate the regional distribution of load projected by Stone & Webster. This was extremely difficult, because there was very little information available about Pakistan's intentions regarding regional development. A physical planning section of the Planning Commission was set up in recent years, but it remains a small body and it did not appear to have had the opportunity of devoting thought to the kind of long-term regional development trends relevant to load forecasting. The Bank Group came to the conclusion, on the basis of what thin evidence it had, that, as far as could be seen, the growth of industry and particularly of power-intensive industry would, as Stone & Webster had projected, tend to be greater in the South than in the North of West Pakistan through the Perspective Plan period.[2]

Future Load Forecasting in West Pakistan

Besides evaluating the Stone & Webster load forecasts, the Bank Group also gave attention to the future of load forecasting in West Pakistan. It is essential that load forecasting be a continuous process, especially in the condition of dynamic economic growth that West Pakistan established during the Second Plan period. WAPDA recognized this with the establishment of its Power Market Survey Organization. The Bank Group thinks that some of the procedures used by that Organization, as implied in the preceding paragraphs, could be improved and it has therefore summarized at the end of this Annex some suggestions. In the course of its work the Bank Group also adopted some approaches which it believes could be of use in future load-forecasting work in West Pakistan.

Contingency Load Forecasting

Given the uncertainties surrounding much of the basic data available in West Pakistan and inevitably relating to long-term projections into the future, the Bank Group believes that it would be appropriate for WAPDA to work with more than one load forecast, especially when major decisions, such as regarding EHV transmission, are in question. The Bank Group used the Stone & Webster forecast (adjusted for the revised IACA pumping forecast) as the Main Load

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1/ See Annexes 2 and 3.
2/ See further Annex 2.

Forecast for its studies but it also developed a Contingency Load Forecast, which was used in testing some decisions and would have been used more extensively had time been available. The Contingency Load Forecast relates to the Northern Grid area. There were a number of difficulties relating to this area. In the first place, despite the importance of the Northern Grid in the total power system of the Province, there is great uncertainty about the real magnitude of current loads. In most years of the Second Plan period there was a certain amount of load shedding and voltage reduction, and in 1965-67 this load shedding became quite acute, variously estimated for instance in December 1966 at between 100 and 200 mw. Later in 1967 and early in 1968 it should be possible to obtain a better reading of actual loads in the North than has been possible for some years; in the meantime uncertainty continues. In the second place, as explained in Chapter IV, WAPDA/Harza, Stone & Webster and the Bank Group appeared to be very largely in agreement on load forecasts except in the case of the basic (i.e. non-agricultural) load in the Northern Grid area. In the third place, there are some major uncertain factors regarding loads in the North, which could put them higher than projected by Stone & Webster. WAPDA allows a peak load for Tarbela construction power of about 80-85 mw against Stone & Webster's 50-55 mw. WAPDA also projects an increase of 15 mw in the load at the Wah Ordnance Factory (a load which Stone & Webster held constant) by 1970 and an increase of general industrial load by that date some 40-50 mw higher than projected by Stone & Webster. There are other potential new industrial loads in the North that could be important at later dates, such as a steel mill at Kalabagh[1/] and a plant to produce sulphuric acid from local gypsum for use in the manufacture of phosphatic fertilizer. The Bank Group believes that its Main Load Forecast has sufficient margin to cover most of these possible developments, except the rather large additional loads projected by WAPDA for 1970. In general, however, there is uncertainty about the extent to which the transfer of Government from Karachi to Islamabad and the Government's emphasis on industrial development outside Karachi may result in greater growth than projected in the Main Forecast of large-scale commercial and industrial load in the North.

In face of these uncertainties regarding existing loads and likely growth of industrial and commercial loads in the North the Bank Group adopted for its Contingency Load Forecast a projection of basic loads based on a trend prepared by Harza Engineering Company. Stone & Webster's load forecast has a sounder analytical base and seemed, on a Province-wide basis, to be on the optimistic side; as indicated in preceding paragraphs, it was carefully built up item by item. The Harza trend is simply a rough extrapolation of load growth (from the base-year figures developed by Stone & Webster for 1965) at annual rates declining from 14 percent per annum during the Third Plan period to about 10 percent during the Sixth Plan period. It is approximately consistent

1/ See Annex 2

with the projection of the Power Market Survey Organization for the Third Plan. The revised IACA pumping load was used in conjunction with both the Stone & Webster and the Harza forecasts of basic load. Table 2 shows the two forecasts.

Table 2

Alternative Load Forecasts for Northern Grid Area
(million kwh)

	1965	1970	1975	1980	1985	Annual Rate of Growth (%)
Main Forecast (Stone & Webster)						
Basic Load	1,820	3,100	4,600	7,040	10,270	9.0
Pumping Load	680	1,514	2,628	3,547	4,793	10.3
Total	2,500	4,614	7,228	10,587	15,063	9.5
Contingency Forecast (Harza)						
Basic Load	1,820	3,480	5,900	9,596	15,453	11.3
Pumping Load	680	1,514	2,628	3,547	4,793	10.3
Total	2,500	4,994	8,528	13,143	20,246	11.0

Projected Peak Loads
(mw)

Main Forecast (Stone & Webster)	473	889	1,402	2,021	2,878
Contingency Forecast (Harza)	473	967	1,591	2,521	3,928

The Harza figures would seem to make ample allowance for the uncertainties discussed above. It ends with a basic load in 1985 some 50 percent higher than that used by Stone & Webster. The rough techniques underlying the Harza projection would seem to be adequate for a secondary Contingency Load Forecast and, in view of the difficulty of making predictions with any degree of precision in West Pakistan, the Bank Group believes that WAPDA would be wise to prepare itself for different eventualities by using a number of alternative load forecasts.

Integration of Load Forecasting with Economic Planning

Another aspect of load forecasting which merits serious attention from WAPDA and the Planning Commission is the integration and reconciliation of power load forecasts with general economic projections. All who have been connected with load forecasting in West Pakistan have strongly urged that it be more closely integrated with economic

planning and forecasting. Harza pointed to the fact there are fairly definite relationships, for different types of industry, between their output and electric energy consumption. It recommended the collection of the requisite statistics for West Pakistan's industry and the development of relationships between economic parameters and loads. Stone & Webster attempted to develop such relationships, but without success. A fundamental difficulty at present is the dearth of reliable statistics even on the existing situation in the Province. Economic statistics, though still of very poor quality, are gradually being improved by the Central Statistical Office, Planning Commission and Government departments. Yet little attempt seems to have been made to gather power statistics in such a way that economic relationships could be developed to assist in future load forecasting. Stone & Webster recommend the establishment of a joint economic and power group to help in load forecasting. This is a priority need, and one of the first tasks of such a group should be to specify the uniform statistics required and to develop programs for their collection on a continuing basis.

To assist in the evaluation of the Stone & Webster load forecast and to help in the development of concepts linking economic planning and power planning, the Bank Group undertook some exercises described in greater detail in Annexes 2 and 3. Regarding industrial loads base year (1962/63) data were developed on value added and electricity consumption by industrial sector. The resultant sectoral power intensities (kwh consumed per PRs 10 of value added) were inspected and adjusted and used to help in forecasting loads on the basis of projected sectoral growth of output. Special attention was devoted to industries which are heavy consumers of power such as fertilizer and cement. With respect to residential loads, the Bank Group tried to analyze some of the components of residential load growth -- such as growth of demand by existing consumers, number of new consumers to be added in each plan period and their initial level of consumption -- and to relate the movement of these components to anticipated changes in some economic variables like family income levels and income distribution. The Bank Group believes that both these approaches could be developed into useful links between power planning and economic planning.

Reserve Generating Capacity Criterion

Another aspect of power planning in West Pakistan which merits attention is the supplement that is made to the forecast loads in order to provide adequate reserve generating capacity. A number of different approaches to this question have been adopted so far, but little serious study has been devoted to assessing what would be a correct reserve criterion in planning the expansion of the power system. In practice the problem has not been very important in the past since the utilities have had enough difficulty expanding capacity fast enough just to keep up with the growth of load; also the existing power systems have been relatively small so that reserve generating capacity was not a major item from the financial point of view. Nevertheless the power crisis of 1966/67 can be seen partly as the result

of failure to provide adequate reserve generating capacity in the Northern Grid. Moreover the power system is now becoming large enough that reserve capacity will be a more important item financially. The subject also merits special attention because the advent of Mangla and Tarbela, with their tremendous fluctuations in capability over the course of the year, will greatly alter the nature of the power system. The Bank Group has in fact adopted a somewhat stricter reserve criterion than Harza: 12 percent of thermal capability and 5 percent of hydro capability over and above peak loads in the 10-day period when hydro capability is at its lowest in the year, as compared with Harza's approach of calculating reserves on the basis of the second lowest 10-day period in the year and effectively allowing no reserves in the minimum 10-day period. The difference in practice is not as simple since Harza defines its loads without any allowance for tubewell interruption. The Bank Group defines its loads net of interruption on public tubewells. Moreover, as pointed out above, the Harza forecast of basic load for the Northern Grid is substantially higher than the forecast used by the Bank Group and may therefore already allow for some of the uncertainties for which the Bank Group makes supplementary allowance in its reserve criterion. What is clear is that neither of the two approaches is more than a rule of thumb.

With the completion of Mangla and the installation of increasing numbers of public tubewells there will be a number of additional factors to be taken into account in a serious study designed to identify an appropriate reserve criterion. So far attention has mainly been given to assessing the probability of outages of different durations on thermal equipment on the basis of past experience in West Pakistan.1/ Much more attention will now need to be given to the effects of hydrological uncertainty, taking account of such things as the possibilities of maintaining higher minimum drawdown levels in years of above-average river flow and variations in the amount of energy required for pumping purposes under different conditions of surface water availability. Besides the hydrological aspects, the study of appropriate reserves should take into account a number of diverse factors such as the degree of certainty of the load forecasts (or the probability rating to be applied to each alternative forecast), delays encountered in securing spare parts or additional equipment as a result of the dependence on imports for supplies, the feasibility of rate agreements with selected large consumers with a built-in provision for contingent load shedding, the economic effects of unplanned load shedding, and the pressures that develop among industrialists who have experienced serious unreliability of utility power supply to purchase their own generating equipment. All of these factors must be considered within the context set by the facts that a very large proportion of energy will for the next decade be coming from what should be a highly reliable hydroelectric plant and that, on any

1/ See, for instance, the interesting paper by A. Rahimtoola, "WAPDA Northern Grid System: Determination of Firm Generating Capacity" (October 1966).

reasonably foreseeable operation policy for Mangla reservoir, the period of minimum generating capability on the system should be of relatively short duration (cf. Table 64 and accompanying discussion in Chapter VI of Volume IV).

Summary Comments on Future Load Forecasting

The load forecast provides the essential frame of reference for system planning and is one of the main elements used in assessing the investment resources that should be allocated to the power sector. If West Pakistan is to develop a power system that is commensurate with its needs it is very important that the load forecasts used be soundly based and consistent with plans for the development of the rest of the economy. Some suggestions that arise from this Annex regarding the ways in which WAPDA's load forecasting might be strengthened are summarized below.

(i) Procedures for the collection of statistics should be reappraised with a view to increasing the reliability of the figures gathered, the speed with which they are made available, and their relevance for load forecasting and system planning purposes. Loads should be classified in groups which are useful for planning purposes because the loads have similar technical characteristics or are found to be subject to similar forces of growth. For instance commercial and residential loads should be considered separately from one another and so should public and private tubewell loads. Urban loads should be distinguished from rural loads, where possible. The categories should be compatible with categories used in economic planning.

(ii) Load forecasting should be coordinated with economic planning and forecasting to a much greater extent than it is now. This should be done not only on a Province-wide basis but, to the extent possible, on a regional basis, taking into account trends and plans for the growth of different sectors of the economy in different parts of the Province.

(iii) WAPDA load forecasting and system planning should be coordinated with similar work in KESC. This will involve agreement on the types of statistics to be collected and the statistical classifications to be used in projections. Long-term planning can only be performed effectively on a Province-wide basis. At present there appears to be duplication of effort, KESC planning to have sufficient capacity to meet Hyderabad loads for instance and WAPDA still planning on the assumption that it will have to have sufficient capacity in its systems to meet the same loads.

(iv) Load forecasts should be clearly related to past trends, analyzed on the basis of the statistical concepts and categories referred to in (i) above.

(v) Services concerned with the collection and analysis of statistics and with load forecasting should be strengthened so

that the results of their work are made available to management for decision-making purposes as soon as possible.

(vi) More attention should be given to the time pattern of loads, both the daily pattern of loads and different classes of loads in different areas and the monthly pattern of loads. Likely changes in these patterns should be analyzed. This will become important as the system expands and as more of the generating capacity on the system is of the multipurpose hydroelectric type with its capability fluctuating over the course of the year. Statistics and analyses of this type will be very valuable for efforts to make best possible use of the capacity and energy that will be available and to select appropriate pricing policies. Detailed daily load data are also needed in the near future in connection with decisions regarding interruption of the tubewell load.

(vii) Many of the rules of thumb used by the Power Market Survey Organization in forecasting loads -- for instance regarding load factors and rates of growth of different classes of load -- still appear to be based on assumptions first made several years ago. Empirical data should be collected and analyzed to see whether these assumptions are in fact correct. The rate of growth that is assumed to characterize residential load, for instance, seems low.

(viii) A range of load forecasts of different durations and with differing amounts of regional detail are required rather than the single five-year load forecast now prepared. It may be that the detailed town-by-town and district-by-district analysis now used for the five-year forecast is not needed quite so far ahead. It does seem that there will be increasing need for a very detailed two-three year load forecast, specifying loads by towns and districts and by much shorter periods than the whole year now used; this will be important for distribution-line work, decisions regarding system operation, etc. A solidly based ten-year forecast, with details for the main regions of the Northern Grid and for the Sukkur and Hyderabad systems, together with some estimates with an analytical basis regarding the trend in the monthly pattern of loads, seem necessary for adequate planning of the large investments now being considered. A more global 20-year estimate, still using classifications of load rather than aggregate system peaks, and somewhat similar to Stone & Webster's projection in methodology, would seem appropriate to indicate the longer-term perspective.

(ix) Important decisions should be made on the basis of analyses with more than one load forecast, given the uncertainty that inevitably surrounds long-term projections.

(x) The approach that should be taken to reserve generating capacity in planning system development needs a thorough appraisal in light of the new conditions that will come into being as units are installed at Mangla and an increasing share of the total load is for pumping purposes.

APPENDIX I

THE PUMPING LOAD FORECAST

Projection of Irrigation Water Requirements

The first stage in the procedure for developing projections of pumping loads is an assessment of irrigation water requirements in different areas. The irrigation and agriculture consultants projected cropping patterns (proportions of each area devoted to each of several crops in kharif season and rabi season) for each of the 61 canal commands into which they divided the basin. This was done on the basis of a number of factors such as present cropping patterns, the quality of climate and soils in each region, anticipated increases in crop yields, anticipated future national requirements of food and fiber, the farmer's preference for growing certain crops when water becomes available and the possibilities of concentrating the production of certain crops in areas with an absolute advantage in their production. The consultants also projected cropping intensities that they considered the maximum feasible in each canal command, assuming all constraints arising from shortage of water removed; the maximum cropping intensity attainable after full irrigation development was in most areas considered to be 150 percent (see Volume II, Annex 2.3).

The amounts of irrigation water required to sustain these cropping patterns at the assumed maximum intensities were obtained by aggregating the monthly water requirements of each crop in the cropping pattern. The requirements for individual crops were computed at the watercourse head by means of the following formula:

$$\text{Monthly Crop Water Requirements} = \frac{(LE \times CF - EP) + PIR - SMR}{FE \times WF}$$

where LE = Monthly lake evaporation, in feet per acre, being the amount of water that will evaporate from open-surface water in the specific climatic conditions of each area.

CF = Crop Factor, or consumptive use coefficients, reflecting the ratio between the consumptive use of a specific crop and lake evaporation; the factors vary by month and by crop according to the development stage and the growth habit of crops.

EP = Effective Precipitation, or amount of rainfall in each month, in terms of feet, which can be expected to be useful for crop growth, taking account of the quantities in which the rain falls (e.g. too little to be effective or too much in a few hours for it to be absorbed) and the existence of special features, such as bunds, which may help to conserve the water for crop use.

PIR = Preirrigation Requirement, for purposes of field preparation a few weeks before planing -- generally assumed to be four inches for kharif crops and three inches for rabi crops.

SMR = Soil Moisture Recovery, the amount of water stored in the soil and recovered by crops at the end of the growing season, generally assumed to be equal to two-thirds of the PIR.

FE = Field Irrigation Efficiency, the percentage of water supplied at the field which is effectively available for crop growth and not lost to deep percolation or to run-off. The irrigation consultant adopted a provision for percolation losses of 30 percent of total supply, in order to make adequate allowance for leaching requirements, so that FE was 70 percent.

WF = Watercourse Loss Factor, the percent of water available at watercourse head which is effectively conveyed to the field. The irrigation consultant assumed 10 percent as watercourse loss, so that WF was 90 percent.

Application of this formula to each crop in each month of the year for each canal command, on the basis of the assumed cropping intensity, led to a summary figure of monthly irrigation water requirements, in terms of acre-feet, for each canal command. Adjustments between months were sometimes made to avoid undesirable peaks, by transferring up to 15 percent of the requirements in a peak month to the preceding month. It was considered that the soils had sufficient moisture-holding capacity for this to be done without seriously affecting crop growth.

Canal Command Analyses

In their analysis of each canal command, the irrigation consultant made an assessment of how the monthly irrigation water requirements might be met from a combination of groundwater and surface water under various assumed conditions of irrigation development. Surface water was generally assumed to be available in amounts dictated by one of three different conditions, depending on the stage of development reached in each canal command: (a) 'historic' deliveries, being generally the average of deliveries over the years 1952-63 (b) deliveries to meet requirements up to the capacity of the existing canal system (c) deliveries required to meet full irrigation water requirements at the maximum intensity. Condition (c), which assumed enlargement of the canals, was ultimately adopted for areas where existing canal capacities were insufficient to reach the maximum cropping intensities projected. In all three cases the analyses were carried out both with and without tubewell development. Wherever public tubewell development was considered, the analysis proceeded by making maximum possible use of groundwater, within the constraint of balanced recharge and, where groundwater was somewhat saline (between 1,000 and 3,000 parts per million Total Dissolved Solids), within the constraint of certain assumed mixing ratios. Thus surface water was in effect the residual, brought in as necessary to support and complement groundwater development.

Once the program of groundwater and surface water development had been drawn up, indicating which of the several conditions listed above

for surface water availability and which of several alternative groundwater development conditions would be relevant for each canal command in the reference years 1975 and 1985, it was possible to use the canal command analyses for indicating the monthly amount of groundwater pumping that would be required in each canal command. Very little canal enlargement was considered feasible or desirable by 1975, given the extensive opportunities that exist for groundwater development. Thus surface-water condition (b) was the relevant one in most canal commands for this year. Groundwater in excess of 3000 ppm TDS was assumed unusable for irrigation purposes, and so the cropping intensity in zones underlain by such groundwater was determined by the ratio between the capacity of the surface distribution system and the peak month water requirements. For instance, if the peak monthly requirement was 0.300 MAF and the canal discharge limit was 0.100 MAF, then the feasible cropping intensity would be only one-third the maximum attainable intensity assumed in the derivation of water requirements. However there would be some need for drainage pumping in such an area, especially if canal remodeling were to be undertaken so that more surface water could be brought in, and the computer was programmed to print out the amount of unusable groundwater that would need to be pumped out over the course of the year in order to maintain a steady water table.

In zones underlain by groundwater of less than 3000 ppm, groundwater could be pumped for irrigation use. The irrigation consultant assumed that groundwater of 2000-3000 ppm could be used (in the Punjab) for irrigation provided it was first mixed with surface water in a ratio of 2½ parts of surface water to one part of groundwater. Groundwater of between 1000 and 2000 ppm could be used provided it was mixed in a ratio of 1:1 with surface water. Groundwater of less than 1000 ppm could be applied directly to the crops.

In areas where groundwater had to be mixed with surface water before application to the crops the amount and monthly pattern of contributions to total irrigation supply that could be made from groundwater would depend closely on the capacity of canals supplying that area. The actual feasible cropping intensity was again derived by multiplying the maximum attainable intensity for that area by the ratio between canal capacity and peak-month requirements of surface water. For instance, in an area with the same canal discharge characteristics and peak month water requirements as described above but underlain by groundwater between 1000 and 2000 ppm, the feasible intensity would be two-thirds the maximum attainable -- 0.100 MAF being supplied by surface deliveries and 0.100 MAF from the groundwater aquifer. All monthly water requirements would be scaled down by one-third, and, since continuous mixing was assumed to be required, one-half of the actual water requirements in each month would be met by groundwater and one-half by surface water. Checks were made to see that the amount of groundwater pumped over the course of the year was equivalent to the amount of recharge that would occur in a mean-flow year, in order to observe the principle of balanced recharge which the consultants had established for their planning.

In calculating the intensity that would be feasible from the point of view of water supply the two seasons were treated separately, with the result that the rabi intensity, by reason of its lower water requirements, tended to be proportionately higher than the kharif intensity. For many canal commands there were found to be two peaks during the year, at each of which the canal discharge capacity constraint became effective. In some cases a single month -- such as October -- in which water would be required for both kharif and rabi crops -- was the effective peak, and then kharif and rabi intensities would be reduced in the same proportion.

In zones underlain by groundwater of less than 1000 ppm quality there was more room for choice regarding the monthly pattern of groundwater pumping. Here surface and groundwater were assumed to be completely interchangeable. It was found that the maximum attainable intensity could be reached in these zones without any expansion of canal capacity being required, except in a few areas where the combination of low recharge and small canal capacity prevented this. The total amount of groundwater pumped over the course of the year was again adjusted by trial and error to meet the balanced recharge criterion. Groundwater pumping was concentrated in the rabi months, when river flows are low, within the limit of pumping capacity assumed to be installed. Deficiencies were made up by surface supplies. Kharif pumping in fresh groundwater zones was usually avoided unless dictated by the watercourse requirement exceeding the discharge limit in a kharif month or by the need to balance recharge. The monthly distribution of groundwater pumping in the fresh groundwater areas was further adjusted by a series of weighting factors designed to concentrate pumping to the extent practicable in the early winter months when hydro energy would be in plentiful supply and to minimize pumping in the April-May period when the capability of the hydro plants would be at their lowest point in the year.

In the canal commands which were not covered by the public tubewell program by 1975 some pumping was assumed to take place as a result of private tubewell development. The number of private wells that would be in place was determined independently, on the basis of a projection for each canal command. Private wells were assumed to average one cfs capacity, and the amount of water that would be pumped by them over the course of the year was calculated by assuming an average utilization factor of 27.4 percent (i.e. the pumps would be run for 27.4 percent of the year).

The analysis for 1985 was identical with that described above for 1975, but by that time some of the areas would be in a different stage of development. In particular there would be quite extensive areas underlain by groundwater in excess of 1000 ppm where the canals would have been enlarged. The rather rigid pumping requirements of the mixing zones would therefore loom larger in the overall picture. At the same time some of the areas with unusable groundwater would have been developed; the drainage pumping required there could be carried out at any time it was convenient provided that the total amount of water pumped over the course of the year added up approximately to annual recharge.

In addition to development within the canal commands allowance had also to be made for wells which would be installed outside the canal commanded areas: these were projected separately and generally at a rate of growth, in the several northern areas where they are relevant, comparable to the lowest rate of growth assumed to be achieved in any part of the canal commanded area.

Pumping Energy Requirements

The amount of electrical energy required to pump the quantities of usable and unusable groundwater coming out of this analysis depends essentially on the head from which these quantities of water are pumped in the different areas and the efficiencies of the wells. The following relationship was developed:

$$\text{Energy (in mln. kwh)} = \frac{(1.02 \times H)}{E} \times MAF$$

where H = Operating Head in feet
MAF = Million acre-feet pumped
E = Wire-to-water efficiency of pump, assumed at 40 percent in the case of private wells and 50 percent in the case of public wells.

A small portion of the total amount of groundwater pumped would come from private wells with diesel engines and so would not affect electricity consumption. It was assumed that the percentage of private wells electrified would fall initially to about 30 percent in 1968 and thereafter rise to 50 percent in 1975 and 90 percent in 1985. It was also assumed that private wells would pump from an average total head of 35 feet. This was also adopted in the Sind canal commands as the head for public tubewells, which was assumed not to change significantly over the years. In the Northern Zone, on the other hand, the average depth to water table has been assumed to increase in public tubewell areas as a result of dewatering and overpumping in years of low surface flow. It was assumed that the average operating head would initially be about 40 feet and that it would thereafter increase by nearly one foot a year, in line with the depth to water table, until it stabilized in year 20 after commencement of the project at about 57 feet. 1/ The pumping head on public tubewells in saline or mixing zones was assumed constant and dependent on the capacity of the well: 30 feet for a 2 cfs well, 35 feet for a 3 cfs well and 40 feet for a 4 cfs well.

To obtain a comprehensive picture of pumping energy needs, one or two adjustments and additions had to be made to the groundwater

1/ Thus the annual energy consumption of a 4 cfs well, producing a typical average of about 1,200 acre-feet per annum would increase from about 96,000 kwh to about 120,000 kwh over 10 years.

pumping requirements that came out of the canal command analyses. The analyses showed the situation that would exist once the ultimate state was reached under any particular set of conditions. In practice there would be some canal commands still under development in any specific year because each command would undergo progressive tubewell development and moreover, after completion of well fields, it takes time before full intensities and hence also water use are achieved. However, in the early years after completion of some tubewell schemes, extra energy would be required in order to lower the water table.

Peak Pumping Load

Peak pumping load was derived, in turn, from the calculations of the amount of energy required in each month for pumping purposes. Allowance had to be made for the amount of time the average well might be run in the peak pumping month (Peak Month Utilization Factor) and for the extent to which the wells in an area would be operated at different times (Diversity Factor). If DF is the Diversity Factor and UF the Utilization Factor then the peak pumping demand in an area is given by the following relationship:

$$\text{Peak Demand} = \frac{\text{Pumping Energy} \times \text{DF}}{\text{hours in month} \times \text{UF}}$$

The consultants thought that it was reasonable to assume, for the peak pumping month, that

(a) $DF^2 = UF$
(b) $UF = 70\%$

Therefore

$$\text{Peak Demand} = \frac{\text{Pumping Energy}}{\text{hours in month} \times \text{DF}}$$

$$= \frac{\text{Pumping Energy}}{730 \times .837}$$

In the aggregation of pumping loads for all areas Stone & Webster initially applied an additional 0.9 Diversity Factor but this was later abandoned as it was felt that the load factors which came out of the calculations described above were sufficiently high.

In order to obtain an indication of the amount of additional energy that would have to be generated and additional generating capacity that would have to be available to cover the pumping load, the Peak Load and Energy figures had to be adjusted for distribution losses. These were assumed to be 22 percent of pumping energy sales in 1975 and 19 percent in 1985.

Low Flow Conditions

At a later stage in the Study it was possible to make an explicit allowance for divergences from mean year flow conditions. In the mixing zones there is little flexibility since a continuous supply of fresh surface water must be maintained to permit use of groundwater. However in the fresh groundwater zones, which are much more important quantitatively, additional amounts of groundwater could be pumped in times of surface-water shortage. The resultant overdraft on the aquifer would be subsequently replaced by reducing pumping and increasing surface supplies during periods of high surface water availability. The public tubewell projects prepared by IACA were in fact designed with sufficient capacity to be able to cope with these additional pumping requirements. The figures for mean year monthly drafts on the aquifer which came out of the canal command analyses were adjusted to include the additional draft on the aquifer that would be involved when surface flows were equivalent to those of the eighth lowest out of the 40 years of river-flow record used. In other words the design criterion for the tubewell projects was that they should be capable of meeting requirements in every month in four years out of five. The 'theoretical' pumping capacity for each project was then determined as that required, assuming a 100 percent utilization factor, to meet the pumping requirements of the worst month in four years out of five.

Corresponding to this additional amount of pumping in a low-flow year there would of course be an additional requirement of electric energy. Estimates were made of the quantities involved; they are shown in Table 3 at the end of this appendix. In planning the power system capability it was assumed that these additional loads in poor hydrological years could be handled within system generating reserves (see Annex 6 below). The water shortage that would be compensated by these additional amounts of pumping were basically those that would occur within the fresh groundwater zones themselves, though some of the extra pumping capacity installed would be available in months other than the most critical month for which the tubewell project was designed to provide additional supplies of fresh groundwater to other zones. No allowance was made for the full amount of additional pumping in fresh groundwater zones that would be possible if additional pumping capacity were installed and that might be desirable to substitute for supplies of surface water to neighboring mixing zones even in the design month (see Volume II, Annex 4.1 and IACA Project Reports).

Tubewell Interruption

The 'theoretical' capacity derived by IACA for each public tubewell project was increased 15 percent, partly as a contingency item and partly to provide sufficient tubewell capacity to permit a shutdown of public tubewell pumping capacity during the evening peak on the power system. IACA considered that it would be feasible to shut down the public tubewells in saline areas for four hours at the time of

system peak and those in fresh groundwater areas for two hours. They did not recommend interruption of the wells in mixing zones. Theoretically, at times of peak pumping demand, it would be possible to pump as much groundwater in 22 hours as could be pumped in 24 hours only if there was about nine percent (i.e. 2/24) additional pumping capacity installed. (The 15 percent increase on the 'theoretical' design capacity of the tubewell projects was to include this.) At the same time Stone & Webster had estimated, on the basis of Harza's rate studies for WAPDA, that the true cost to serve public tubewells was presently about 11 paisa per kwh, assuming no interruption. If additional pumping capacity were installed so that plans for installation of generating equipment could be made on the assumption that the public wells would be shed for two hours a day, then, this cost to serve public wells could be reduced by the portion of it which relates to the capital costs of generating equipment. Stone & Webster estimated this at about 1.5 paisa per kwh. Thus a rough comparison could be made on the basis of the economic costs of a 4 cfs well, as compiled by IACA.

Table 1

Comparative Annual Economic Costs of 4 cfs Public Tubewell Pumping 1170 acre-feet Fresh Groundwater Per Annum With and Without 2-Hour Interruption (PRs/year)

	With 2-hr. Interruption	Without Interruption
Depreciation	4,900	4,500
Interest at 8 percent	3,900	3,600
Operation and Maintenance	3,300	3,000
Power (economic costs a/)	9,100	10,540
Total Annual Costs	21,200	21,640

a/ i.e. 11 paisa per kwh without interruption and 9.5 paisa with interruption.

The table shows that, roughly speaking, the annual charges for depreciation and interest on the invested capital amount to a sum which is somewhat below the power charges. Thus a nine percent increase in installed capacity, which would probably give rise to less than the nine percent increase in capital charges shown in the table, is more than offset by a 14 percent saving in power rates. The table, based on conservative assumptions with regard to the savings to be gained by peak saving on the public wells, shows that there is a small but clear saving

to be had from planning for interruption.1/

Given these design criteria, the utilization factor on the public wells in the projects prepared by IACA is 87 percent in the worst month in four years out of five (i.e. 100/115) without interruption in that month and 94 percent in the worst month in four years out of five (i.e. 100/106) with interruption. Since public tubewell projects are indivisible, in the sense that it is not possible to put in some portion of the design number of tubewells to provide some increase in water availability and then to add further wells at a later date,2/ and since the projects are designed for 150 percent cropping intensity a few years will elapse after completion of a tubewell project before utilization factors of this high level require to be attained.

Interruption of public tubewells at the time of daily peak demand was built into the pumping load forecast by rules of thumb corresponding to the principles cited above. Drainage wells in saline

1/ Account was not taken in these computations of the costs of alternative systems for controlling the tubewell load, such as ripple control or time switches. This was because a centralized control system will probably be needed anyway for efficient operation of the public tubewell fields and integration of groundwater supplies with surface water supplies. In this regard Stone & Webster commented: "Economic utilization of water can only be accomplished through a centralized control system. Such a system must of necessity encompass control of tubewells. Control of tubewells therefore becomes a joint venture designed to accommodate both the irrigation and electric systems' needs. This joint need makes immediate action and joint investigations all the more imperative. So far, very little study and no funds have been allocated to this phase of the tubewell program. Such control should become an integral part of each new tubewell project including those projects now in operation or under construction.... It is important that this problem be attached without prejudice and given immediate attention, with plans drawn for its early implementation. Each public tubewell should be equipped with a solenoid motor starter which will enable practically any method of control to be incorporated at a later time after plans are formulated. Each public tubewell should have a 10-kvar capacitor installed on the motor side of the starter. This capacitor will supply the reactive power drawn by the motor and provide a means for automatically removing it from the system when the well is shut down. The installation should be standard with all wells and included as part of the cost of the tubewell installation."

2/ This could of course be done but it would not provide additional supplies of water to the whole project area unless special channels were dug -- which would become superfluous when the additional wells were installed. The projects have in practice to be designed and the wells to be sited in such a way as to meet the needs of an ultimate state of development which may take some years to achieve.

areas were assumed to be shut down for the full four hours of daily peak in the evening. For the wells in usable groundwater zones the working criterion was established that 75 percent of them could be shut down for a prearranged two-hour period. This 75 percent was intended to correspond to the proportion of these wells that would be in fresh groundwater zones. For purposes of the load forecast it was assumed that 35 percent of the wells in usable groundwater zones would be shut down for the first two hours of the evening peak and 35 percent for the second two hours. Table 3 below shows the magnitude of deductions made to allow for interruption, in the two key years 1975 and 1985.

The IACA and Bank Group Tubewell Programs

The IACA public tubewell program and projection of private tubewells, on which the pumping load forecast used here is based, is summarized in Table 2 for the reference years 1975 and 1985. The table also indicates the calculated amounts of electrical energy required for pumping purposes and the amounts of irrigation water which would be supplied from the groundwater aquifer in a mean year. The annual electrical load factors are relatively high because of the allowance for interruption built into the peak pumping load. They are particularly high in the Sind, partly because of the large amount of drainage pumping projected there -- nearly 50 percent of total tubewell pumping by 1985 under mean year flow conditions. The approximate numbers of public tubewells to be installed by 1975 under the Bank Group's final Action Program are shown in the table beneath the IACA program for 1975. The numbers of public tubewells proposed for the North are almost the same in the two programs, but the Bank Group's target for the Sind is substantially larger. This implies that the pumping load forecast used in the power studies may be somewhat too low for the Sind around 1975; consistency with the recommended tubewell program might require that it be higher by about 15 mw or some five percent of the total load projected for the Sind in that year.

Table 2

Tubewell Projections

1975	Punjab	Sind
IACA Program		
Public wells (numbers)	17,090	2,950
Private wells (numbers)	23,470	530
Mean year groundwater deliveries (MAF)	26	4
Energy (mln. kwh)a/ -- public	2,000	365
private	638	15
Total Energy	2,638	380
Peak pumping load b/ (mw)	521	54
Annual load factor (%)	57.8	80.3
Bank Group Program		
Public wells (numbers)	(16,890)	(3,818)

(continued)

1985	Punjab		Sind
IACA Program			
Public wells (numbers)	- - -	34,300	- - -
Private wells (numbers)	22,000		1,000
Mean year groundwater deliveries (MAF)	35		5
Energy (mln. kwh)c/ -- public	4,428		1,176
private	365		17
Total Energy	4,793		1,193
Peak pumping load b/ (mw)	809		157
Annual load factor (%)	67.6		86.8

a/ Including distribution losses at 22 percent of sales to wells.
b/ Net of interruptible.
c/ Including distribution losses at 19 percent of sales to wells.

The Monthly Pattern of Pumping Load

The monthly pattern of pumping load is of considerable importance from the point of view of power system planning. The monthly pattern projected by IACA derives from their canal command studies and water distribution analyses and are the result of a trial and error approach to minimizing shortages. At present river flows in the scarce water season cannot be controlled to any degree, but the completion of Mangla this year will make it possible to regulate rabi flows on the Jhelum. The surface water availabilities in the Punjab canal commands supplied from the Jhelum were adjusted, in the canal command analysis, to take advantage of this potential. When Tarbela is completed there will be considerably more scope for altering the pattern of surface water deliveries in different months of the rabi season. The rabi surface-water requirements at the different stages of development which were derived from the IACA canal command analysis, were subsequently aggregated by IACA (in their water distribution analysis) and carried up to the rim-stations, with allowance for river losses, where they were compared with available flows in different hydrological years. The tentative release patterns on Mangla and Tarbela were drawn up in such a way as to minimize the shortages that would occur in years of lower than average rabi flow.

Thus the monthly pumping patterns finally put forward by IACA and used in these studies were prepared after checking back with the possibility of altering them in a way which would fit better with combined operation of the power and irrigation systems. The patterns finally adopted were in fact the last of a series. They indicate a peak pumping requirement in the Punjab in October, the overlap month between kharif and rabi seasons, and a secondary peak only slightly lower in March. As apparent from the discussion in Chapter VI it is this secondary peak which may be controlling on the power system over

the next 10 years, because this is also the month of minimum capability at Mangla. The March peak arises almost entirely from the requirements for final watering of rabi crops -- especially wheat. It appears that it could become even more important as the Mexican varieties of wheat, with their need for a heavy watering during the final maturing period, become more widespread.

The monthly patterns of peak pumping load finally adopted by IACA are shown for the reference years 1975 and 1985 in Table 3. The Bank Group interpolated between the 1966 pattern of pumping load (as estimated by Stone & Webster) and these 1975 figures, and between 1975 and 1985 on the basis of the schedule of public tubewell projects and the projections of private tubewell development made by IACA. These interpolations are shown, gross of distribution losses and net of interruption at the peak, in Tables 8, 9 and 10 of Appendix 3 to this Annex.

Table 3

Irrigation Consultant's Revised Forecast of Pumping Loads 1975 and 1985
(mw)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1975												
Northern Grid	397	560	581	393	399	434	350	490	523	611	439	373
less interruptible	77	101	99	72	72	81	76	93	99	90	84	66
Net of interruptible	320	459	482	321	327	353	274	397	424	521	355	307
Sind	73	70	65	39	55	68	66	63	62	70	63	66
less interruptible	19	17	16	9	13	17	16	14	15	16	17	16
Net of interruptible	54	53	49	30	42	51	50	49	47	54	46	50
Critical Year Addition	12	35	32	26	30	34	5	0	55	44	14	8
TOTAL	386	547	563	377	399	438	329	446	526	619	415	365
1985												
Northern Grid	620	816	827	647	699	752	618	877	934	954	701	601
less interruptible	122	166	152	115	129	141	152	144	136	145	139	121
Net of interruptible	498	650	675	532	570	611	466	733	798	809	562	480
Sind	187	179	167	151	170	187	180	189	183	200	170	165
less interruptible	45	43	41	35	38	45	43	38	42	43	40	40
Net of interruptible	142	136	126	116	132	142	137	151	141	157	130	125
Critical Year Addition	49	68	71	87	130	124	15	0	55	72	48	36
TOTAL	689	854	872	735	832	877	618	884	994	1038	740	641

APPENDIX II

PRIVATE TUBEWELL ELECTRIFICATION

Existing Numbers of Electrified Wells and Recent Growth

In the past WAPDA has not maintained separate statistics on private tubewells. As a result the surge of private tubewell development was not recognized until some time after it had gotten under way. There is also considerable uncertainty about the role that private tubewells are playing currently in the demand for electricity. For instance there are several different estimates of the number of electrified wells in existence in 1965, which was adopted as the base year for much of the work in the Study. IACA adopted a figure of 9,000 for the number of electrified private wells in existence in 1965. The survey which has been carried out annually in recent years by the Pakistan Institute of Development Economics (PIDE) in conjunction with the West Pakistan Department of Agriculture indicates a figure of about 9,800 electrified private wells in existence in August-September 1965. Stone & Webster, however, used WAPDA statistics on the number of agricultural customers (kept separately and supposed to represent the number of bonafide agricultural customers using tubewells or lift pumps for irrigation purposes, because these are the ones entitled to the subsidized rate of eight paisa per kwh). By subtracting out the number of public tubewells (about 3,600 as of June 30, 1965, including the 1400 Rasul wells of the Irrigation Department) they estimated that there were about 13,000 electrified private wells in operation as of June 30, 1965.

It is hard to choose among these estimates. The Stone & Webster figure is probably on the high side because some of the agricultural customers are undoubtedly owners of lift wells. But there is no evidence to suggest that the number of lift wells in existence is sufficient to account for a large portion of the difference between the estimate based on the PIDE surveys and that based on WAPDA statistics. Assuming no double counting in WAPDA figures, the conclusion must be that either the PIDE figures are a serious underestimate or that many of the wells receiving power at the subsidized rate are not really agricultural wells but wells for village water supply.

It may well be that the PIDE surveys underestimate the number of private wells in existence. The survey indicated a total of about 31,900 private wells installed by 1965, including an estimated 5,000 outside the canal commanded areas and about 700 in the Sind. Subsequent studies by Tipton and Kalmbach in the Bari Doab indicate the existence of a substantially larger number of wells there than suggested by the PIDE study. Taking account of the Tipton and Kalmbach study, the Bank Group has adopted an estimate of about 34,000 private wells installed by 1965 (Volume II, Chapter 4, para 4.64).

The picture with regard to the growth of electrified private tubewells is also quite unclear. The following table compares figures derived from WAPDA statistics with the results of the PIDE surveys.

Table 1

Growth of Electrified Private Tubewells (Numbers in Existence)

	1960	1961	1962	1963	1964	1965	1966
WAPDA Accounts							
Agricultural Customers	3,300	4,663	7,997	9,957	13,519	16,712	21,914
less SCARP Wells (est.)	-	300	1,230	2,043	2,206	2,212	2,342
Irrigation Dept.	1,600	1,660	1,660	1,400	1,400	1,400	1,400
Private	1,700	2,703	5,107	6,514	9,913	13,100	18,172
PIDE Survey of Private Wells							
Electric Wells					6,590	9,800	12,940
Total Wells					25,000	31,900	40,100

The WAPDA figures are supposed to relate to June 30 of the year in question, and the PIDE figures to August-September of each year. The WAPDA figures suggest an increase in the number of electrified private wells in existence, between mid-1964 and mid-1966 of about 8,000 (allowing for some 250 of the agricultural customers added being lift-well operators) while the PIDE figures suggest an increase of about 6,300 over the same period.

Despite the inconsistencies among the figures several conclusions seem to be clear.

(i) The number of private tubewells installed has been increasing extremely rapidly. The Bank Group estimates in Volume II that about 25,000 private tubewells were installed during the Second Plan period.

(ii) The pace of installation of private tubewells has continued to increase, from about 7000 in 1964/65 to over 8000 in 1965/66 according to the PIDE figures, but a few of the wells installed, perhaps 500, may be replacements.

(iii) Less than half the private tubewells in existence are electrified.

(iv) The proportion of private tubewells which is electrified is increasing -- from about 26 percent of total wells installed by 1964 to about 32 percent by 1966, according to PIDE figures. WAPDA numbers of electrified private wells with PIDE numbers for all wells imply that the electrified share rose from 40 percent to 45 percent over the same period.

(v) Absence of electrification does not appear to be a very serious bar to the installation of a private tubewell, since about half the private wells installed in 1964-66 were not electric and the majority of those currently in existence are not electric.

Relative Price to Farmers of Water Pumped by Diesel & Electric Wells

It is not surprising that the proportion of wells electrified has been rising in recent years since it is much cheaper for the farmer

to buy and operate an electric motor than a diesel engine and there has been substantial pressure on WAPDA to extend electrication for private tubewells. The type and size of engine/motor bought by private tubewell owners varies greatly, but typical sizes and costs seem to be an 8-10 kw electric motor costing about PRs 2,500 and a 16 hp diesel engine costing about double this amount. Moreover diesel fuel is heavily taxed. It can be estimated that, at current prices to the farmer for diesel fuel and for electricity, and taking account of the relative capital and maintenance costs for diesel and electric wells, as borne by the farmer, an acre-foot pumped by a diesel well costs him about twice as much as does an acre-foot pumped by a well with an electric motor -- about PRs 26 against PRs 13. Thus at current prices there is a very strong incentive to electrify a private tubewell.

This incentive price structure has grown up partly because it was found, when the private tubewell movement among the farmers was first noticed, that tubewells had sprung up particularly rapidly in areas reasonably close to transmission lines or covered by existing distribution networks. The availability of electricity was in other words a strong incentive to installation of a private tubewell, and to help stimulate the spread of private tubewells it was decided to subsidize the price of electricity. Considering that at least 30-40 percent of the existing private tubewells are electric whereas a far smaller proportion of the areas with groundwater characteristics suitable for private tubewell development have power lines near at hand, it is quite clear that private wells are much more dense in electrified areas than in non-electrified areas. Nevertheless the substantial growth of diesel wells that has occurred also indicates that the profitability of wells is sufficient to make it worthwhile to bear the much heavier costs involved in a diesel operation. It is, moreover, very doubtful whether the subsidy on electricity sold to farmers can have had much stimulative effect since, even if tubewell owners were charged the full cost of the power they consume (estimated by Stone & Webster, on analogy with the price for small industrial loads, at about 13 paisa per kwh) the cost per acre-foot, on a comparable basis to the figures cited above, would be only about PRs 17. This is still 35 percent beneath the cost of an acre-foot pumped by a diesel well.

Expansion of the Electricity Distribution Network

Much more important than the price of electricity in promoting electrification of wells has been the sheer physical availability of electric power. WAPDA has not been able to keep up with the growth of demand for electrification and there has continued to be a large backlog of customers awaiting connection. Figures provided by WAPDA indicate that between July 1, 1960 and June 30, 1965 (the Second Plan period) the achievement in terms of expansion of the distribution system and new connections was impressive; nevertheless concentration of effort on new connections led to some neglect of maintenance on the existing parts of the system, and the expansion was not sufficient to keep up with demand. WAPDA's customers increased about 120 percent over the Second Plan

period from 312,000 to 688,000; the number of electrified villages in the Province more than doubled from about 900 in 1960 to nearly 1900 in 1965; nearly 15,000 miles of distribution line (9,100 miles of 11 kv line and 5,600 miles of 400-volt line) were built. A large proportion of the rural electrification was in connection with the extensive SCARP I project. Some portion of the new customers added to the WAPDA system were simply taken over from small municipal utilities amalgamated with the WAPDA system and some of the distribution line achievement may represent pre-existing lines taken over by WAPDA; nevertheless the achievement was clearly substantial.

Stone & Webster found that their load forecast implied such substantial increase in the number of customers on the WAPDA system over the next 10 years that they were doubtful whether WAPDA would in fact be able to make sufficient connections. Leaving aside new industrial and bulk consumers of power, Stone & Webster drew up a picture of the amount of new distribution line required to service additional general (i.e. residential and commercial) and agricultural customers.

Table 2

Stone & Webster Assessment of Additional Distribution Line Required to Connect New Customers, 1965-75

	1965-70	1970-75
Numbers of New Customers		
General	477,000	671,000
Public wells - fresh	8,400	12,950
saline	150	4,150
Private wells - Special a/	6,000	8,800
Routine b/	8,900	13,100
Miles of Distribution Line (400 volt & 11 kv) Required for		
General (50 customers/mile) c/	9,500	16,800
Wells: Public fresh (1.3 miles/well)	11,000	16,800
saline (0.7 miles/well)	-	2,900
Private special (0.4 miles/well)	2,400	3,500
routine (0.2 miles/well)	1,800	2,600
Total miles line	24,700	42,600

a/ 'Special' private tubewell projects were envisaged as the extension of the distribution system to a whole new area where private wells would be installed.

b/ 'Routine' private tubewell connections were those that would take off from existing lines.

c/ 40 customers/mile in the Fourth Plan period (1970-75).

Stone & Webster adjusted downwards these total estimates of distribution line requirements to eliminate any double counting involved and they thus reached net figures of 20,700 miles of line required for the Third Plan period and 35,600 miles for the Fourth Plan period. Stone & Webster felt these goals, particularly that for the Third Plan period, would be unattainable; it was their view that a total of 16,000 miles of new distribution lines constructed during the Third Plan would represent a maximum effort. They anticipated therefore some curtailment of the tubewell program and village electrification programs.

Relative Economic Costs of Water Pumped by Diesel and Electric Wells

Quite apart from the capability of WAPDA to erect distribution lines and connect private tubewells, questions have been raised as to whether electrification is not really more costly to Pakistan than the continued installation of diesel engines to power private tubewells -- despite the present structure of financial prices which, as indicated, is heavily biased towards encouraging electrification. Such a variety of economic costs, whose precise magnitude is quite uncertain, and so many variables apart from economic costs would enter into formulation of a correct answer to this question that it is impossible to be definitive. It is clear that no single answer could be of general validity given the wide variety of specific circumstances relating to each individual tubewell site. Nevertheless it is clear in general terms that if electrification of private wells is justified economically at all it will be justified up to a certain distance from an existing transmission line or, what comes to the same thing, at a certain density of private wells, but not at greater distances or lower density. Even then the answer remains unclear, given the uncertainty that inevitably exists regarding additional tubewells or other loads that may develop subsequently in the vicinity of the distribution line as a result of the stimulus afforded by its existence.

The Bank Group has attempted some computations relating to the comparison between diesel and electric private tubewells on the basis of the best evidence available to it early in 1967 regarding average economic prices (i.e. prices excluding duties and taxes). The procedure adopted below is to calculate the present-worth costs of a one cusec diesel well, with a 10-year life, pumping about 200 acre-feet a year and to compare them with the present worth capital and maintenance costs of an electric well with the same life and pumping the same quantity of water each year. The difference between these costs, when set over the present worth of the total quantity of electricity required to drive the electric well over its 10-year life indicates the price per kwh at which the economic costs of diesel and electric wells break even. This in turn can be compared with the economic cost of electricity. Depending on the specific assumption initially made regarding the length of distribution line required to connect the private well an indication can thus be obtained as to the maximum distance from existing distribution lines at which it is worthwhile electrifying private tubewells.

All the surveys that have been made of the capital costs of

private tubewells indicate that they vary over a very wide range.[1/] Nevertheless the following figures seem to indicate reasonably well the order of magnitude of the capital costs of one cusec diesel and electric wells.

Table 3

Capital Costs of Diesel and Electric One-Cusec Tubewells
(PRs)

	Electric		Diesel	
	Total	Foreign Exch. Component	Total	Foreign Exch. Component
Drilling	500		500	
Lining	800	300	800	300
Screens	1,000		1,000	
Pit and Shed	1,200		1,200	
Pump	500		500	
Motor/Engine	2,500	1,500	5,000	2,750
	6,500	1,800	9,000	3,050

The difference in capital costs occurs entirely in the cost of the motor/engine -- diesel costing about twice as much as electric. Both electric motors and diesel engines are manufactured in Pakistan, but imported materials and components are very important in both. It is estimated that the real foreign exchange component is about 50 percent of the cost of each.

In terms of direct capital cost an electric well thus appears to be significantly cheaper than a diesel well, but when account is taken of the costs of installing the requisite distribution lines it is clear that the electric well involves a much greater initial capital outlay. 'Theoretical' costs of constructing distribution lines and connecting private wells, on the assumption that a complete network of wells can be established in a diagonal array so that quantities of lines per well are minimized, are of the same order of magnitude per well as the total direct capital costs of an electric well cited in Table 3. Practical experience has shown that the cost incurred by WAPDA in connecting private wells has ranged between somewhat less than PRs 10,000 and nearly PRs 50,000 per well. The duty on distribution equipment is relatively high in West Pakistan, so that economic costs would have been substantially less -- perhaps a maximum of something under PRs 40,000.

It appears that typical experience has been to build about half a mile of distribution line -- partly 11 kv and partly 400 volt line -- per private tubewell. A reasonable figure for the costs of these lines (including lattice steel structures, insulators, guys, anchors, conductors, etc. and erection) would be about PRs 20,000 per mile. Some lower and

1/ See, for instance, IACA Comprehensive Report, Volume 5, Annexure 7 -- Water Supply and Distribution, page 36.

some higher figures have been cited, but this appears to be a conservative estimate, erring towards the high side. Besides the lines a step-down transformer is required of about 10 kva -- or larger if there are other loads in the neighborhood. And there is the actual service connection (installation of meter, etc.). Table 4 summarizes these costs.

Table 4

Costs of Connecting a Private Tubewell to the Distribution System
(PRs)

	Costs inc. taxes & duties
½ mile of 400 volt/11 kv line	10,000
Transformer	1,100
Service connection	200
Total	11,300

About 25 percent of this total is estimated to be tax and duty, and about 30 percent foreign exchange. Thus the economic cost per well is about PRs 8,500 with a foreign exchange component of PRs 3,400. Addition of these to the direct cost items listed in Table 3 suggests a total economic cost per electric tubewell, including connection with the distribution system, of about PRs 15,000, with a foreign exchange component of about PRs 5,200.

Maintenance costs tend to be considerably higher on diesel wells than on electric wells. They are estimated at about PRs 500 per annum on electric wells, including spares, as compared with about PRs 1,000 per annum on diesel wells. No allowance has been made for any foreign exchange component in maintenance costs.

Diesel oil, as pointed out above, bears a very heavy tax, but even without the tax it is expensive compared with electricity and it has a high foreign exchange component. By agreement between the Government authorities and the marketing companies diesel oil is sold at a uniform ex-depot price throughout West Pakistan. This price represents an agreed fixed sale price ex-depot Karachi, including taxes, plus a surcharge to cover freight Karachi-Rawalpindi. The surcharge for freight goes in the first place to the Government but is recoverable by the marketing companies to the extent it is needed to cover freight costs incurred by them. Some of the private tubewells in existence in West Pakistan have light engines, doing about 1500 rpm, and using High Speed Diesel Oil (HSD), but more typical is a low speed 160 rpm engine using Low Speed or light diesel oil. Table 5 summarizes the components of the current costs of a gallon of each type.

Table 5

Current Price of Diesel Oil in West Pakistan
(PRs per Imperial Gallon)

	Light (Low Speed)	HSD (High Speed)
Import/Excise Duty	0.46	1.08[a]
Defense Surcharge	0.12	0.27
Development Surcharge	0.07	0.11
Total Tax Component	0.65	1.46
Development Surcharge (Freight)	0.25	0.27
Karachi Selling Price	0.50	0.56
Total ex-depot price	1.40	2.29
Agents' commission	0.02	0.03
Average Octroi at depot station	0.02	0.03
Average delivery charge	0.05	0.05
Agents' handling cost	0.07	0.07
Price delivered farmer (incl. taxes)	1.56	2.47
Price delivered farmer (excl. taxes)	0.91	1.01
Direct foreign exchange cost	0.38	0.40

a/ Since June 1963 farmers have been entitled to a rebate of 20 percent of the duty on HSD sold to them for use in tractors, tubewells and lift pumps for agricultural purposes: allowance for this rebate would make the price delivered to the farmer including taxes about PRs 2.26 per gallon.

In the table the freight surcharge is treated as a cost rather than a tax. The table indicates that the net-of-tax prices for the two types of diesel oil is very close, at about PRs 0.90 and PRs 1.00 per imperial gallon. Since most tubewell-using farmers are not as far from Karachi as Rawalpindi is, so that the rail portion of the transit to them would cost less than PRs 0.27 per gallon, it would seem that a reasonable economic price for diesel fuel used for agricultural purposes would be about 85-95 paisa per imperial gallon. Since a one-cusec 16 hp diesel well would require about 1,750 gallons to pump 200 acre-feet, the annual fuel cost, at a diesel oil price of about 90 paisa per gallon and with a small allowance for lubricating oil, would be about PRs 1,614, with a foreign exchange component of about PRs 700.

The following cost streams, representing capital and maintenance costs on an electric well and capital, maintenance and fuel costs on a diesel well were discounted back to 1967 at eight percent, resulting in the present-worth figures indicated at the bottom of the table. The shadow exchange rate adopted was twice the current exchange rate.

Table 6

Ten-Year Cost Streams, Electric and Diesel Wells (excluding cost of electricity) and Discounted Present Worth as of 1967
(PRs)

	Electric Wells		Diesel Wells	
	Current Exchange Rate	Shadow Exchange Rate	Current Exchange Rate	Shadow Exchange Rate
1967	15,000	20,200	9,000	12,050
1968	500	500	2,614	3,314
1969	500	500	2,614	3,314
1970	500	500	2,614	3,314
1971	500	500	2,614	3,314
1972	500	500	2,614	3,314
1973	500	500	2,614	3,314
1974	500	500	2,614	3,314
1975	500	500	2,614	3,314
1976	500	500	2,614	3,314
1977	500	500	2,614	3,314
P.W., 1967	18,355	23,555	26,537	34,284

The amount of electricity required to raise about 200 acre-feet from a well with a pumping head of about 35 feet, assuming a 40 percent wire-to-water efficiency, is somewhat less than 20,000 kwh. The present worth in 1967 of a 10-year stream of 20,000 kwh per annum is about 134,000 kwh. Division of the differences between the present-worth costs of diesel and electric wells calculated above by this number of kwh indicates the electricity prices at which diesel and electric wells, on the given assumptions break even: 6.1 paisa/kwh for calculations at the current exchange rate and 8.0 paisa/kwh for calculations at the shadow exchange rate.

Before these prices are useful for our purpose one other adjustment has to be made to allow for the fact that, even though the private wells may have lives of only 10 years, the electricity distribution system should have an economic life of about 30 years. To allow for this the value of the life left in the distribution installations in 1977 is taken as two-thirds of the initial cost and this value is discounted back to 1967. Deduction of this allowance from the present-worth figures for the electric alternative widens the gap between the present-worth costs of the electric and diesel wells. The resultant break even electricity prices, calculated in the same fashion as described above, are about 8 paisa/kwh with calculations using the current foreign exchange rate and 10.5 paisa/kwh with calculations using the shadow foreign exchange rate.

How do these break-even prices compare with the economic cost of producing and delivering a unit of electricity to the private

tubewell? The capital costs of the last link of the distribution system, which carries power from the transmission system to the well, have been included in the cost of the well; and the main transmission and distribution system is assumed preexistent for purposes of this analysis. Therefore the cost of electricity which is relevant for this comparison is one which covers WAPDA's operating costs and in addition, assuming no interruption of the tubewell at the time of system peak,[1] the costs of generating capacity required to cover the tubewell load. As the WAPDA system expands and includes more hydro-generation at dams for which the primary justification is agricultural that a relatively small proportion of the capital costs are attributable to power, WAPDA's unit costs will decline. But the best figures available for the present comparison seem to be historic ones. WAPDA's total operating costs in fiscal 1963/64, including fuel, maintenance of all equipment and establishment charges, but excluding depreciation and interest charges, averaged 4.5 paisa per kwh. As regards capital costs of generation, a reasonable allowance would be annual depreciation (assuming a 20-year life) and interest charges (at 8 percent) on the capital cost of gas turbines (assumed in this report at $107 or PRs 509 per net kw installed, excluding taxes, duties and interest during construction, with a foreign exchange component of about 85 percent). The annual capital charges for 8 kw of generating capacity would be about PRs 367 or, divided by 20,000 kwh, 1.8 paisa per kwh; at the higher foreign exchange rate they would be about 3.4 paisa per kwh. However this would not be an adequate allowance for capital costs of generation, since it fails to allow for transmission and distribution losses -- which will inevitably be high on sales to private tubewells. These losses may range anywhere from about 40 percent to as much as 100 percent of sales. A reasonable assumption would be 75 percent losses, so that the allowance for generating capacity must be 175 percent of the charges for the 8 kw peak load of a private tubewell cited above.

The results of these computations are summarized in Table 7, which suggests that the overall economic costs of driving a one-cusec well electrically, assuming it involves construction of not more than half-a-mile of distribution line, compare favorably with the costs of driving such a well with a diesel engine. If the private tubewell can be interrupted at the peak (it might then have to have some 10 percent larger installed capacity -- see Annex 1, Appendix I above -- but the costs of this extra capacity would be small) the comparison would be much more favorable to electrically-driven wells because the capital charge component on the electricity would be eliminated.

1/ The Bank Group's consultants have assumed that it is impractical at present to interrupt private tubewells. Private tubewell load has of course been shed in the past -- particularly during the power crisis of 1966/67 -- but only by means of switching off power supplies to a whole area or by voluntary cooperation of the farmer, since there is no centralized control system for agricultural wells alone. The power consultant suggests that after experience has been gained with interruption of public wells (see Annex 1, Appendix I) it may become feasible and worthwhile to extend the control system to private wells.

Table 7

Comparison of Actual Unit Cost of Electricity Delivered to Private Tubewell with Unit Cost at which Electrically-Driven Well breaks even with a Diesel-Powered Well
(Paisa per kwh)

	Current Exchange Rate	Shadow Exchange Rate
Unit cost of electricity		
- current costs	4.5	4.5
- capital charges (generation)	3.2	6.0
Total	7.7	10.5
Break-even price of electricity (diesel vs. electric wells)		
- without allowance for full life of distribution system	6.1	8.0
- with allowance for full life of distribution system	8.0	10.5

The break-even price is in effect the maximum price that the farmer could afford to pay for electricity (assuming he were charged economic prices), under the given conditions, because if the price were higher it would be preferable for him to use a diesel engine. The table shows that, at the current exchange rate, the price he could afford to pay is slightly higher than the unit cost of electricity, while at the higher foreign exchange rate the prices are identical.

Given the fact that the real economic cost of electricity is likely to show a downward trend, whereas there is no reason why the economic cost of diesel fuel should fall,[1] the weight of economic argument seems to favor installation of electric motors rather than diesel engines on private tubewells whenever the need for distribution line is less than about half-a-mile per well. As costs fall, and more particularly if interruption of private wells becomes possible on a planned basis, then this 'maximum length of line justifiable' will increase substantially towards about one mile per well.

Distribution-Line Requirements of Recommended Program

It was suggested above that the average length of line which WAPDA has had to install in recent years to connect private tubewells

1/ It might in fact rise if there was a very sharp increase in the amount of diesel fuel required in West Pakistan, unaccompanied by any comparable increase in the demand for fuel oil. Either the diesel oil would have to be imported as such (whereas the prices used here are those applicable to the products of the Karachi refineries) or the refineries would produce larger surpluses of fuel oil than they do now; these current surpluses are already a problem and are sold abroad at relatively low prices.

may be about half a mile. Table 2 showed that Stone & Webster had assumed that about 0.4 miles of line would be required per well to connect private wells in 'special private tubewell electrification project areas' and about 0.2 miles would be required per well for routine connections taking off from existing distribution and transmission lines. These allowances seem on the low side compared with Harza's calculations indicating about 0.3 - 0.4 mile per well on the assumption that the wells could be laid out in perfect grid pattern. In practice private tubewells will be very irregularly spaced.

The number of tubewells finally projected under the Bank Group's program is also different from the number assumed by Stone & Webster in their report.

Table 8

Projections of Public and Private Wells (Numbers)

	1965	1970	1975	1985
Stone & Webster Report				
Public	2,015	10,565	27,650	33,150
Private[a]	12,250	27,150	49,050	88,350
IACA Program				
Public	2,200	9,500	20,000	44,100
Private[a]	9,000	17,000	24,000	23,000
Bank Group Program				
Public	2,200	9,600	20,700	

a/ Electrified wells only, including those both inside and outside the canal commanded areas.

The Bank Group has not made separate projections of the number of private tubewells which will be electrified, and the load forecasts used in the studies described in these volumes have been based on the IACA projection of electrified private wells. The Bank Group's projection of the total number of private wells which will be in existence over the next decade is somewhat larger than IACA's: 55,500 by 1970 against IACA's 52,000 and 52,500 by 1975 against IACA's 48,000. But the differences between the Bank Group's final projection and IACA's are not large.

The difference between the numbers of electrified private wells projected to exist at the beginning and at the end of a five-year period is not a good indication of the number of electric well installations projected for that period because it is assumed that existing private wells, including electric ones, will be largely eliminated as the area in which they are located comes under the

public tubewell program. Taking account of the regional distribution of private electric wells and of the areas to be covered by the public well program, we can estimate that the number of private wells expected to be electrified over the coming years under the Bank Group/IACA program is about 8,500 during the Third Plan and 14,000 during the Fourth Plan.

On the basis of data provided by WAPDA regarding miles of distribution line constructed during the Second Plan period for the public tubewell program and for other purposes and using Stone & Webster's assumption that about 50 non-agricultural customers are connected per mile of 11 kv and 400 volt line installed, it is possible to make a rough estimate of the amounts of distribution line that will be required to implement the program recommended in this Report, and bring loads up to the levels forecast here. 363,000 new non-agricultural customers were added to the WAPDA system during the Second Plan. If one mile of distribution line was required for every 50 such customers, making a total of about 7,200 miles of line, then the remainder of the total built during the Second Plan or about 7,500 miles of line must have been for agricultural customers; about 1,800 miles were for public tubewells, according to WAPDA data so that the rest must have been for private tubewells. This assumption leads to an average figure of 0.5 miles of line per private tubewell connected during the Second Plan. This figure is used as the basis for projecting the miles of line required for private tubewell electrification in the following table.

According to the rough projections given in the table WAPDA will need to construct about 23,000 miles of distribution of line during the Third Plan and 35,000 miles during the Fourth Plan. This would mean improving on the performance of the Second Plan by about 60 percent during the Third Plan and more than doubling Second Plan performance during the Fourth Plan. These do not seem impossible targets, although they are ambitious. They appear to be attainable within the rupee estimates given in Chapter X for capital expenditures on distribution during the Third and Fourth Plan periods.

Table 9

WAPDA Systems: New Customers Connected and Miles of Distribution Line Required, 1960-75

	Second Plan (1960-65)	Third Plan (1965-70)	Fourth Plan (1970-75)
Numbers of new customers			
Non-agricultural	363,000	500,000	700,000
Public tubewells	2,100	7,000	11,000
Private tubewells	11,400	8,500	14,000
Total	376,500	515,500	725,000
Miles of distribution line required			
for Non-agricultural a/	7,260	10,000	14,000
Public tubewells b/	1,806	9,100	14,300
Private tubewells c/	5,637	4,250	7,000
Total	14,703	23,350	35,300

a/ Assume 50 non-agricultural customers per mile of line.

b/ Figure for Second Plan is actual, as reported by WAPDA; figures for Third and Fourth Plans are projected at 1.3 miles of line, following SCARP reports.

c/ Figure for Second Plan is residual from total miles of line built after subtracting allowances for non-agricultural customers and public tubewells (see footnotes 1 and 2). Adopting the WAPDA agricultural customer figures as the best indication of new electric well installations during the Second Plan, we find this works out at about 0.5 miles per private tubewell. This per-well figure is assumed to continue to apply through the Third and Fourth Plan periods.

APPENDIX III

LOAD DATA USED IN COMPUTER STUDIES

1. Northern Grid Peak Loads (mw)
2. Northern Grid Minimum Loads as % of Peak Loads
3. Northern Grid Monthly Market Load Factors
4. Southern Market (Karachi-Hyderabad) Peak Loads (mw)
5. Southern Market Minimum Loads as % of Peak Loads
6. Southern Market Monthly Market Load Factors
7. Central Market (Upper Sind) Peak Loads (mw)
8. Northern Grid - Irrigation Consultant's Revised Pumping Load Forecast (mw)
9. Upper Sind - Irrigation Consultant's Revised Pumping Load Forecast (mw)
10. Lower Sind - Irrigation Consultant's Revised Pumping Load Forecast (mw)
11. Northern Grid Peak Loads (mw) - Higher Load Forecast
12. Northern Grid - Higher Load Forecast - Minimum Load as % of Peak Load
13. Northern Grid - Higher Load Forecast - Monthly Market Load Factors

Table 1

NORTHERN GRID PEAK LOADS (mw)

(Power consultant's basic loads plus irrigation consultant's pumping loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	463.	453.	455.	459.	482.	482.	483.	511.	517.	513.	486.	505.
1967	513.	512.	514.	511.	536.	538.	534.	570.	576.	577.	542.	560.
1968	579.	596.	598.	585.	612.	618.	605.	652.	662.	668.	621.	637.
1969	662.	685.	690.	659.	687.	698.	672.	736.	746.	764.	701.	715.
1970	751.	808.	813.	767.	790.	813.	784.	869.	882.	889.	809.	818.
1971	839.	908.	909.	839.	863.	893.	849.	950.	968.	989.	888.	892.
1972	924.	1002.	1004.	919.	945.	980.	928.	1043.	1064.	1093.	974.	975.
1973	1012.	1095.	1099.	1011.	1031.	1068.	1009.	1138.	1161.	1196.	1062.	1061.
1974	1098.	1192.	1196.	1090.	1121.	1162.	1098.	1239.	1264.	1302.	1157.	1155.
1975	1190.	1302.	1306.	1192.	1227.	1281.	1202.	1344.	1371.	1402.	1245.	1235.
1976	1261.	1392.	1394.	1286.	1324.	1382.	1298.	1452.	1482.	1502.	1340.	1330.
1977	1361.	1492.	1493.	1389.	1433.	1495.	1406.	1573.	1605.	1714.	1446.	1437.
1978	1470.	1602.	1601.	1504.	1553.	1619.	1525.	1705.	1740.	1736.	1562.	1554.
1979	1592.	1711.	1708.	1617.	1671.	1742.	1642.	1837.	1875.	1859.	1677.	1670.
1980	1709.	1855.	1837.	1738.	1813.	1874.	1769.	1979.	2021.	1988.	1801.	1766.
1981	1834.	1981.	1959.	1867.	1951.	2016.	1904.	2129.	2176.	2126.	1932.	1897.
1982	1965.	2113.	2087.	2004.	2095.	2163.	2045.	2289.	2339.	2271.	2069.	2034.
1983	2104.	2254.	2225.	2149.	2248.	2322.	2197.	2459.	2514.	2426.	2216.	2179.
1984	2239.	2389.	2356.	2289.	2398.	2474.	2342.	2625.	2685.	2575.	2358.	2319.
1985	2391.	2543.	2505.	2446.	2567.	2649.	2504.	2811.	2878.	2743.	2517.	2477.

Table 2

NORTHERN GRID MINIMUM LOADS AS % OF PEAK LOADS

(applicable to load forecast composed of Power Consultant's Basic and Irrigation Consultant's Pumping Forecasts)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.250	0.260	0.260	0.260	0.300	0.250	0.260	0.360	0.340	0.360	0.250	0.250
1967	0.250	0.280	0.300	0.260	0.300	0.250	0.260	0.360	0.340	0.360	0.250	0.250
1968	0.250	0.320	0.320	0.260	0.280	0.260	0.260	0.340	0.340	0.380	0.250	0.250
1969	0.250	0.400	0.340	0.260	0.280	0.260	0.250	0.340	0.340	0.380	0.250	0.250
1970	0.250	0.400	0.360	0.250	0.260	0.260	0.250	0.320	0.340	0.400	0.250	0.250
1971	0.250	0.400	0.360	0.250	0.260	0.260	0.250	0.320	0.340	0.400	0.250	0.250
1972	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.400	0.260	0.250
1973	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.400	0.260	0.250
1974	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.400	0.260	0.250
1975	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.420	0.260	0.250
1976	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.420	0.260	0.250
1977	0.250	0.400	0.380	0.250	0.250	0.260	0.250	0.320	0.340	0.420	0.260	0.250
1978	0.250	0.400	0.380	0.250	0.250	0.280	0.250	0.320	0.360	0.420	0.260	0.250
1979	0.250	0.400	0.380	0.250	0.250	0.280	0.250	0.340	0.360	0.420	0.260	0.250
1980	0.250	0.400	0.380	0.260	0.260	0.280	0.250	0.340	0.360	0.420	0.280	0.250
1981	0.260	0.400	0.380	0.260	0.260	0.280	0.250	0.340	0.380	0.420	0.280	0.250
1982	0.260	0.380	0.380	0.260	0.260	0.300	0.250	0.360	0.380	0.420	0.280	0.250
1983	0.280	0.380	0.380	0.260	0.260	0.300	0.260	0.360	0.380	0.420	0.280	0.260
1984	0.280	0.380	0.380	0.260	0.280	0.300	0.260	0.380	0.400	0.420	0.300	0.260
1985	0.280	0.380	0.380	0.260	0.280	0.300	0.260	0.380	0.400	0.420	0.300	0.260

Table 3

NORTHERN GRID MONTHLY MARKET LOAD FACTORS

(applicable to load forecast composed of Power Consultant's Basic and Irrigation Consultant's Pumping Forecasts)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.570	0.630	0.630	0.630	0.650	0.620	0.630	0.680	0.670	0.680	0.610	0.600
1967	0.580	0.640	0.650	0.630	0.650	0.620	0.630	0.680	0.670	0.680	0.610	0.600
1968	0.600	0.660	0.660	0.630	0.640	0.630	0.630	0.670	0.670	0.690	0.610	0.600
1969	0.600	0.680	0.670	0.630	0.640	0.630	0.620	0.670	0.670	0.690	0.620	0.600
1970	0.610	0.700	0.680	0.620	0.630	0.630	0.620	0.660	0.670	0.700	0.620	0.600
1971	0.610	0.700	0.680	0.620	0.630	0.630	0.620	0.660	0.670	0.700	0.620	0.600
1972	0.610	0.700	0.690	0.620	0.620	0.630	0.610	0.660	0.670	0.700	0.630	0.600
1973	0.610	0.700	0.690	0.620	0.610	0.630	0.610	0.660	0.670	0.700	0.630	0.600
1974	0.610	0.700	0.690	0.620	0.610	0.630	0.610	0.660	0.670	0.700	0.630	0.600
1975	0.610	0.700	0.690	0.620	0.620	0.630	0.600	0.660	0.670	0.710	0.630	0.600
1976	0.610	0.700	0.690	0.620	0.620	0.630	0.600	0.660	0.670	0.710	0.630	0.600
1977	0.610	0.700	0.690	0.620	0.620	0.630	0.600	0.660	0.670	0.710	0.630	0.610
1978	0.610	0.700	0.690	0.620	0.620	0.640	0.600	0.660	0.680	0.710	0.630	0.610
1979	0.620	0.700	0.690	0.620	0.620	0.640	0.610	0.670	0.680	0.710	0.630	0.610
1980	0.620	0.700	0.690	0.630	0.630	0.640	0.610	0.670	0.680	0.710	0.640	0.620
1981	0.630	0.700	0.690	0.630	0.630	0.640	0.620	0.670	0.690	0.710	0.640	0.620
1982	0.630	0.690	0.690	0.630	0.630	0.650	0.620	0.680	0.690	0.710	0.640	0.620
1983	0.640	0.690	0.690	0.630	0.630	0.650	0.630	0.680	0.690	0.710	0.640	0.630
1984	0.640	0.690	0.690	0.630	0.640	0.650	0.630	0.690	0.700	0.710	0.650	0.630
1985	0.640	0.690	0.690	0.630	0.640	0.650	0.630	0.690	0.700	0.710	0.650	0.630

Table 4

SOUTHERN MARKET (KARACHI-HYDERABAD) PEAK LOADS (MW)

(Power Consultant's Basic Loads plus Irrigation Consultant's Pumping Loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	158.	158.	163.	169.	174.	177.	178.	184.	187.	194.	194.	194.
1967	183.	184.	189.	196.	201.	206.	206.	212.	217.	225.	225.	225.
1968	225.	223.	230.	236.	244.	248.	249.	254.	262.	271.	269.	268.
1969	276.	265.	273.	281.	289.	294.	295.	301.	310.	321.	318.	318.
1970	319.	316.	326.	336.	345.	351.	352.	359.	369.	382.	379.	378.
1971	370.	367.	378.	389.	399.	407.	408.	415.	427.	442.	439.	438.
1972	432.	429.	441.	453.	465.	473.	475.	484.	497.	514.	510.	509.
1973	516.	509.	522.	539.	555.	564.	566.	582.	587.	600.	591.	589.
1974	596.	588.	603.	621.	640.	652.	654.	665.	677.	692.	675.	680.
1975	686.	677.	694.	712.	734.	748.	751.	764.	779.	795.	782.	781.
1976	766.	756.	774.	796.	819.	840.	839.	853.	869.	889.	874.	872.
1977	861.	849.	871.	894.	921.	939.	942.	958.	977.	998.	981.	979.
1978	978.	945.	971.	1007.	1039.	1069.	1068.	1087.	1102.	1101.	1081.	1078.
1979	1095.	1060.	1089.	1130.	1164.	1187.	1196.	1217.	1235.	1234.	1209.	1207.
1980	1217.	1177.	1208.	1254.	1293.	1318.	1330.	1352.	1372.	1370.	1344.	1350.
1981	1330.	1287.	1319.	1372.	1414.	1421.	1453.	1478.	1500.	1499.	1469.	1465.
1982	1456.	1409.	1445.	1503.	1549.	1579.	1591.	1620.	1642.	1642.	1609.	1604.
1983	1607.	1553.	1595.	1663.	1725.	1760.	1770.	1801.	1799.	1776.	1728.	1721.
1984	1756.	1697.	1745.	1815.	1886.	1925.	1937.	1971.	1968.	1944.	1889.	1882.
1985	1924.	1858.	1906.	1993.	2066.	2107.	2115.	2154.	2150.	2122.	2064.	2059.

TABLE 5

SOUTHERN MARKET MINIMUM LOADS AS % OF PEAK LOADS

(applicable to load forecast composed of Power Consultant's Basic and Irrigation Consultant's pumping forecasts)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.300	0.300	0.300	0.280	0.280	0.300	0.300	0.280	0.300	0.300	0.300	0.300
1967	0.320	0.320	0.320	0.280	0.320	0.320	0.320	0.300	0.320	0.320	0.300	0.320
1968	0.300	0.320	0.320	0.300	0.300	0.320	0.300	0.320	0.300	0.320	0.300	0.320
1969	0.280	0.320	0.320	0.300	0.320	0.320	0.320	0.320	0.300	0.320	0.300	0.300
1970	0.320	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.300	0.300
1971	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.300	0.320
1972	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.300	0.320
1973	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.320	0.320
1974	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.320	0.320
1975	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.320	0.320
1976	0.340	0.320	0.320	0.320	0.320	0.340	0.320	0.320	0.300	0.320	0.320	0.320
1977	0.340	0.320	0.320	0.320	0.320	0.320	0.320	0.320	0.300	0.320	0.320	0.320
1978	0.320	0.320	0.320	0.320	0.300	0.320	0.320	0.320	0.300	0.320	0.300	0.320
1979	0.320	0.320	0.300	0.300	0.300	0.320	0.320	0.320	0.300	0.320	0.300	0.320
1980	0.320	0.320	0.300	0.300	0.300	0.300	0.320	0.300	0.300	0.320	0.300	0.300
1981	0.320	0.320	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.320	0.300	0.300
1982	0.300	0.320	0.300	0.300	0.280	0.300	0.300	0.300	0.300	0.300	0.300	0.300
1983	0.300	0.320	0.300	0.300	0.280	0.300	0.300	0.300	0.300	0.300	0.300	0.300
1984	0.300	0.320	0.300	0.300	0.280	0.300	0.300	0.300	0.300	0.300	0.300	0.300
1985	0.300	0.320	0.300	0.300	0.280	0.300	0.300	0.300	0.300	0.300	0.300	0.300

Table 6

SOUTHERN MARKET MONTHLY MARKET LOAD FACTORS

(applicable to load forecast composed of Power Consultant's Basic and Irrigation Consultant's Pumping Forecasts)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.650	0.650	0.650	0.640	0.640	0.650	0.650	0.640	0.650	0.650	0.650	0.650
1967	0.660	0.660	0.660	0.650	0.660	0.660	0.660	0.650	0.660	0.660	0.660	0.660
1968	0.650	0.660	0.660	0.650	0.650	0.660	0.650	0.660	0.650	0.660	0.650	0.660
1969	0.640	0.660	0.660	0.660	0.660	0.660	0.660	0.660	0.650	0.660	0.650	0.650
1970	0.660	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.650	0.650
1971	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.650	0.660
1972	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.650	0.660
1973	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.660	0.660
1974	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.660	0.660
1975	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.660	0.660
1976	0.670	0.660	0.660	0.660	0.660	0.670	0.660	0.660	0.650	0.660	0.660	0.660
1977	0.670	0.660	0.660	0.660	0.660	0.660	0.660	0.660	0.650	0.660	0.660	0.660
1978	0.660	0.660	0.660	0.660	0.650	0.660	0.660	0.660	0.650	0.660	0.650	0.660
1979	0.660	0.660	0.650	0.660	0.650	0.660	0.660	0.660	0.650	0.660	0.650	0.660
1980	0.660	0.660	0.650	0.660	0.650	0.650	0.660	0.650	0.650	0.660	0.650	0.650
1981	0.660	0.660	0.650	0.660	0.650	0.650	0.650	0.650	0.650	0.660	0.650	0.650
1982	0.650	0.660	0.650	0.660	0.640	0.650	0.650	0.650	0.650	0.650	0.650	0.650
1983	0.650	0.660	0.650	0.650	0.640	0.650	0.650	0.650	0.650	0.650	0.650	0.650
1984	0.650	0.660	0.650	0.650	0.640	0.650	0.650	0.650	0.650	0.650	0.650	0.650
1985	0.650	0.660	0.650	0.650	0.640	0.650	0.650	0.650	0.650	0.650	0.650	0.650

Table 7

CENTRAL MARKET (UPPER SIND) PEAK LOADS (MW)

(Power Consultant's Basic Loads plus Irrigation Consultant's Pumping Loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	9.	9.	9.	10.	10.	10.	10.	10.	10.	11.	10.	11.
1967	15.	15.	14.	14.	14.	15.	16.	15.	15.	17.	15.	16.
1968	19.	19.	18.	17.	19.	20.	20.	19.	20.	22.	20.	21.
1969	25.	25.	24.	23.	24.	26.	27.	26.	26.	29.	27.	28.
1970	39.	39.	39.	37.	39.	41.	42.	41.	42.	45.	42.	44.
1971	47.	47.	47.	44.	47.	49.	50.	50.	50.	54.	51.	53.
1972	57.	58.	56.	52.	55.	59.	60.	59.	60.	65.	60.	64.
1973	67.	67.	67.	59.	65.	68.	69.	70.	71.	76.	71.	73.
1974	80.	81.	78.	68.	76.	81.	81.	82.	83.	89.	83.	85.
1975	96.	96.	93.	80.	90.	97.	97.	97.	98.	105.	96.	101.
1976	104.	101.	100.	88.	100.	108.	107.	109.	108.	115.	108.	110.
1977	116.	114.	111.	98.	109.	117.	117.	118.	118.	126.	116.	119.
1978	124.	123.	122.	109.	120.	127.	129.	129.	129.	137.	125.	129.
1979	135.	133.	130.	119.	131.	139.	139.	141.	140.	148.	136.	138.
1980	147.	145.	143.	132.	144.	152.	152.	155.	152.	162.	147.	150.
1981	161.	158.	156.	147.	159.	167.	167.	170.	168.	178.	161.	163.
1982	177.	173.	171.	162.	174.	184.	183.	188.	185.	193.	176.	178.
1983	191.	187.	186.	179.	192.	201.	199.	205.	201.	210.	190.	192.
1984	207.	203.	201.	197.	210.	219.	217.	225.	219.	229.	207.	208.
1985	227.	222.	220.	218.	231.	240.	237.	248.	242.	250.	226.	226.

Table 8

Northern Grid
Irrigation Consultant's Revised Pumping Load Forecast (mw)
(including losses & net of interruption)

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1966	88.	98.	108.	92.	103.	94.	95.	121.	121.	129.	98.	97.
1967	103.	121.	132.	107.	118.	111.	107.	139.	141.	155.	115.	111.
1968	124.	154.	166.	128.	140.	135.	122.	164.	169.	191.	138.	129.
1969	152.	198.	214.	155.	166.	166.	140.	198.	203.	238.	169.	155.
1970	181.	245.	263.	185.	188.	199.	163.	229.	242.	287.	201.	178.
1971	209.	300.	315.	210.	214.	230.	179.	259.	277.	340.	232.	201.
1972	244.	350.	367.	245.	249.	269.	209.	302.	323.	397.	270.	234.
1973	272.	391.	411.	273.	279.	300.	233.	338.	361.	444.	302.	261.
1974	298.	427.	449.	299.	304.	328.	255.	370.	395.	485.	331.	286.
1975	320.	459.	482.	321.	327.	353.	274.	397.	424.	521.	355.	307.
1976	334.	475.	498.	338.	346.	373.	289.	422.	452.	544.	372.	321.
1977	349.	492.	515.	355.	365.	394.	305.	449.	481.	569.	389.	336.
1978	365.	509.	533.	374.	386.	416.	322.	477.	512.	594.	408.	351.
1979	382.	527.	551.	393.	408.	439.	339.	507.	545.	622.	427.	367.
1980	399.	545.	570.	413.	431.	463.	358.	539.	581.	649.	447.	384.
1981	417.	564.	580.	435.	456.	490.	378.	572.	619.	678.	468.	402.
1982	436.	584.	609.	458.	482.	517.	399.	609.	659.	709.	490.	421.
1983	455.	605.	630.	482.	509.	546.	421.	647.	702.	741.	513.	440.
1984	476.	626.	651.	507.	539.	576.	444.	688.	748.	774.	537.	460.
1985	498.	650.	675.	532.	570.	611.	466.	733.	798.	809.	562.	480.

Table 9

Upper Sind -- Irrigation Consultant's Revised Pumping Load Forecast (mw)
(including losses and net of interruption)

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1966	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.
1967	3.	3.	2.	2.	2.	3.	3.	2.	2.	3.	2.	2.
1968	4.	4.	3.	2.	3.	4.	4.	3.	3.	4.	3.	3.
1969	6.	6.	5.	3.	4.	6.	6.	5.	5.	6.	5.	5.
1970	8.	8.	7.	5.	6.	8.	8.	7.	7.	8.	7.	7.
1971	11.	11.	10.	7.	9.	11.	11.	10.	10.	11.	10.	10.
1972	17.	17.	15.	10.	13.	16.	16.	15.	15.	17.	14.	16.
1973	23.	22.	21.	13.	18.	21.	21.	21.	21.	23.	20.	21.
1974	31.	31.	28.	17.	24.	29.	28.	28.	27.	31.	27.	28.
1975	41.	40.	37.	23.	32.	39.	38.	37.	36.	41.	35.	38.
1976	44.	43.	40.	25.	35.	42.	41.	41.	39.	44.	38.	41.
1977	48.	46.	42.	28.	38.	45.	44.	44.	42.	48.	41.	43.
1978	50.	49.	46.	32.	41.	48.	48.	48.	46.	52.	44.	46.
1979	54.	52.	48.	35.	45.	52.	51.	52.	50.	56.	48.	49.
1980	59.	57.	53.	40.	50.	57.	56.	58.	54.	62.	52.	53.
1981	64.	61.	57.	45.	55.	62.	61.	63.	60.	68.	57.	57.
1982	70.	67.	62.	50.	60.	68.	66.	70.	66.	74.	62.	62.
1983	75.	72.	67.	57.	67.	74.	72.	77.	72.	81.	67.	67.
1984	81.	78.	72.	64.	74.	81.	78.	85.	79.	89.	74.	72.
1985	89.	86.	79.	73.	83.	89.	86.	95.	89.	99.	82.	79.

Table 10

Lower Sind -- Irrigation Consultant's Revised Pumping Load Forecast (mw)
(including losses and net of interruption)

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1966	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1967	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1968	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1969	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1970	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1971	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1972	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
1973	3.	3.	2.	1.	2.	3.	3.	2.	2.	3.	2.	3.
1974	7.	7.	7.	4.	6.	7.	7.	7.	6.	7.	6.	7.
1975	13.	13.	12.	7.	10.	12.	12.	12.	11.	13.	11.	12.
1976	15.	15.	14.	9.	12.	15.	14.	14.	13.	16.	13.	14.
1977	18.	18.	17.	11.	15.	18.	17.	17.	17.	19.	16.	17.
1978	22.	21.	19.	13.	18.	21.	20.	21.	19.	22.	19.	20.
1979	26.	25.	23.	17.	21.	25.	24.	25.	23.	27.	22.	23.
1980	29.	28.	26.	19.	24.	28.	27.	28.	27.	30.	25.	26.
1981	33.	32.	29.	23.	28.	32.	31.	33.	31.	35.	29.	30.
1982	37.	36.	33.	27.	33.	37.	35.	38.	35.	40.	33.	33.
1983	42.	41.	37.	32.	38.	42.	40.	43.	41.	46.	38.	37.
1984	47.	46.	43.	37.	43.	48.	46.	50.	47.	53.	43.	42.
1985	53.	50.	47.	43.	49.	53.	51.	56.	52.	58.	48.	46.

Table 11

NORTHERN GRID PEAK LOADS (MW) - HIGHER LOAD FORECAST

(Harza Basic Loads plus Irrigation Consultant's Pumping Loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	468.	458.	460.	464.	487.	487.	488.	516.	522.	524.	493.	507.
1967	533.	551.	547.	542.	573.	576.	572.	614.	616.	600.	565.	571.
1968	599.	629.	621.	613.	640.	645.	632.	689.	694.	676.	633.	634.
1969	717.	763.	759.	725.	761.	776.	750.	823.	828.	818.	759.	755.
1970	821.	885.	879.	835.	859.	889.	853.	934.	947.	967.	886.	860.
1971	926.	1017.	1005.	936.	968.	1004.	953.	1049.	1067.	1076.	977.	963.
1972	1044.	1150.	1137.	1055.	1089.	1149.	1069.	1182.	1203.	1217.	1150.	1114.
1973	1162.	1231.	1271.	1173.	1209.	1255.	1193.	1318.	1271.	1374.	1242.	1251.
1974	1288.	1382.	1449.	1339.	1374.	1398.	1265.	1460.	1410.	1500.	1366.	1356.
1975	1370.	1509.	1492.	1381.	1427.	1483.	1404.	1547.	1574.	1591.	1445.	1417.
1976	1504.	1645.	1628.	1528.	1576.	1633.	1549.	1712.	1742.	1744.	1592.	1565.
1977	1679.	1822.	1790.	1695.	1755.	1819.	1730.	1909.	1941.	1929.	1771.	1746.
1978	1825.	1969.	1933.	1849.	1916.	1986.	1892.	2082.	2117.	2089.	1923.	1901.
1979	1987.	2132.	2096.	2018.	2093.	2164.	2064.	2272.	2310.	2267.	2092.	2072.
1980	2164.	2310.	2270.	2203.	2286.	2363.	2258.	2479.	2521.	2454.	2287.	2259.
1981	2357.	2504.	2459.	2400.	2496.	2580.	2468.	2707.	2754.	2668.	2493.	2467.
1982	2571.	2719.	2664.	2618.	2722.	2812.	2694.	2959.	3009.	2899.	2705.	2691.
1983	2805.	2955.	2890.	2862.	2974.	3071.	2946.	3232.	3287.	3151.	2953.	2940.
1984	3061.	3211.	3091.	3122.	3254.	3360.	3228.	3528.	3588.	3424.	3217.	3205.
1985	3338.	3490.	3410.	3412.	3555.	3666.	3521.	3863.	3928.	3719.	3522.	3490.

Table 12

NORTHERN GRID - HIGHER LOAD FORECAST - MINIMUM LOAD as % of PEAK LOAD

(applicable to load forecast composed of Harza Basic Loads and Irrigation Consultant's Pumping Loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.250	0.260	0.260	0.260	0.300	0.250	0.260	0.360	0.340	0.360	0.250	0.250
1967	0.250	0.260	0.300	0.260	0.300	0.250	0.260	0.360	0.340	0.360	0.250	0.250
1968	0.250	0.280	0.320	0.260	0.280	0.250	0.260	0.340	0.340	0.360	0.250	0.250
1969	0.250	0.280	0.340	0.260	0.280	0.250	0.250	0.340	0.340	0.360	0.250	0.250
1970	0.250	0.320	0.360	0.250	0.260	0.250	0.250	0.340	0.340	0.360	0.250	0.250
1971	0.250	0.320	0.360	0.250	0.260	0.260	0.250	0.320	0.320	0.360	0.250	0.250
1972	0.250	0.320	0.380	0.250	0.260	0.260	0.250	0.320	0.320	0.360	0.250	0.250
1973	0.250	0.360	0.380	0.250	0.250	0.260	0.250	0.320	0.320	0.360	0.260	0.250
1974	0.250	0.360	0.380	0.250	0.250	0.260	0.250	0.320	0.320	0.360	0.260	0.250
1975	0.250	0.360	0.380	0.250	0.250	0.260	0.250	0.300	0.320	0.360	0.260	0.250
1976	0.250	0.360	0.380	0.250	0.250	0.260	0.250	0.300	0.320	0.360	0.260	0.250
1977	0.250	0.360	0.360	0.250	0.250	0.260	0.250	0.300	0.320	0.340	0.260	0.250
1978	0.250	0.340	0.360	0.250	0.250	0.260	0.250	0.300	0.320	0.340	0.260	0.250
1979	0.250	0.340	0.340	0.250	0.250	0.260	0.250	0.300	0.320	0.340	0.260	0.250
1980	0.250	0.340	0.340	0.250	0.250	0.260	0.250	0.320	0.320	0.320	0.260	0.250
1981	0.250	0.340	0.340	0.250	0.250	0.260	0.250	0.320	0.340	0.320	0.260	0.250
1982	0.250	0.320	0.340	0.250	0.250	0.260	0.250	0.320	0.340	0.320	0.260	0.250
1983	0.250	0.320	0.320	0.250	0.260	0.260	0.250	0.320	0.340	0.320	0.260	0.250
1984	0.250	0.320	0.320	0.250	0.260	0.260	0.250	0.320	0.340	0.320	0.260	0.250
1985	0.250	0.320	0.320	0.250	0.260	0.260	0.250	0.320	0.340	0.320	0.260	0.250

Table 13

NORTHERN GRID - HIGHER LOAD FORECAST - MONTHLY MARKET LOAD FACTORS

(applicable to load forecast composed of Harza Basic Loads and Irrigation Consultant's Pumping Loads, net of interruption)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1966	0.570	0.630	0.630	0.630	0.650	0.620	0.630	0.680	0.670	0.680	0.610	0.600
1967	0.580	0.630	0.650	0.630	0.650	0.620	0.630	0.680	0.670	0.680	0.610	0.600
1968	0.600	0.640	0.660	0.630	0.640	0.620	0.630	0.670	0.670	0.680	0.610	0.600
1969	0.600	0.640	0.670	0.630	0.640	0.620	0.620	0.670	0.670	0.680	0.620	0.600
1970	0.610	0.660	0.680	0.620	0.630	0.620	0.620	0.670	0.670	0.680	0.620	0.610
1971	0.610	0.660	0.680	0.620	0.630	0.630	0.620	0.660	0.660	0.680	0.620	0.610
1972	0.610	0.660	0.690	0.620	0.630	0.630	0.610	0.660	0.660	0.680	0.620	0.610
1973	0.610	0.680	0.690	0.620	0.620	0.630	0.610	0.660	0.660	0.680	0.630	0.610
1974	0.610	0.680	0.690	0.620	0.610	0.630	0.610	0.660	0.660	0.680	0.630	0.610
1975	0.610	0.680	0.690	0.620	0.610	0.630	0.600	0.650	0.660	0.680	0.630	0.610
1976	0.610	0.680	0.690	0.620	0.610	0.630	0.600	0.650	0.660	0.680	0.630	0.610
1977	0.610	0.680	0.680	0.620	0.610	0.630	0.600	0.650	0.660	0.670	0.630	0.610
1978	0.610	0.670	0.680	0.620	0.610	0.630	0.610	0.650	0.660	0.670	0.630	0.610
1979	0.610	0.670	0.670	0.620	0.620	0.630	0.610	0.650	0.660	0.670	0.630	0.610
1980	0.620	0.670	0.670	0.620	0.620	0.630	0.610	0.660	0.660	0.660	0.630	0.620
1981	0.620	0.670	0.670	0.620	0.620	0.630	0.610	0.660	0.670	0.660	0.630	0.620
1982	0.620	0.660	0.670	0.620	0.620	0.630	0.620	0.660	0.670	0.660	0.630	0.620
1983	0.620	0.660	0.660	0.620	0.630	0.630	0.620	0.660	0.670	0.660	0.630	0.620
1984	0.620	0.660	0.660	0.620	0.630	0.630	0.620	0.660	0.670	0.660	0.630	0.620
1985	0.620	0.660	0.660	0.620	0.630	0.630	0.620	0.660	0.670	0.660	0.630	0.620

ANNEX 2

THE INDUSTRIAL LOAD FORECAST

THE INDUSTRIAL LOAD FORECAST

Table of Contents

THE INDUSTRIAL LOAD FORECAST

The Stone & Webster Industrial Load Forecast

Stone & Webster's industrial load forecast projects an increase in the amount of electricity consumed in the industrial sector of the economy, including industrial self-generation, from about 1,600 million kwh in 1964 to about 13,500 million kwh in 1985. The annual rate of growth of industrial consumption is expected to average about 10.5 percent over the 20-year period 1965 to 1985, but to be substantially higher in the early years, averaging 13.0 percent per annum during the Third Plan period. Industrial consumption of electricity is estimated to have grown at an average rate of about 10 percent per annum over the years 1960 to 1964 when growth may have been held back to some extent by shortage of generating capacity. The industrial load on the public utilities has of course been growing at a much more rapid rate -- above 16 percent per annum -- as more industries have been transferring to supply from the public utilities. Table 1 summarizes the Stone & Webster industrial load forecast by areas, and Appendix Table I compares these figures with the growth achieved between 1960 and 1964 in the different areas.

Table 1

The Stone & Webster Industrial Load Forecast
(Million kwh)

	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.

The power consultant's industrial load forecast was based primarily on an examination of the climate for industrial investment in the different regions of West Pakistan and on consideration of industrial projects actually sanctioned for investment during the Third Plan period; in using these industrial lists, he made some allowance for delays in project execution. He also had a macroeconomic framework for the growth of West Pakistan, provided by the Perspective Planning Section of the Pakistan Planning Commission, as well as load forecasts made by WAPDA and its consultants. The data available on the Perspective Plan corresponds essentially to that presented in Appendix Table VII below, though it was less detailed.

The Bank Group reexamined the power consultant's industrial load forecast and reached the conclusion that although it may err on the high side for the Fourth Plan period and on the low side in the later years, it is not too far out of line. When compared with the industrial growth framework provided by the Planning Commission, it would appear to be substantially too high. However, the Planning Commission's framework as now set up may be overly pessimistic about the industrial growth rate that could be achieved in West Pakistan in the next two decades.

Stone & Webster project a particularly rapid rate of growth of industrial consumption of electrical energy in Karachi -- largely due to their assumption that a number of relatively power-intensive industries such as petrochemicals, steel and oil-refining will be established there. They also anticipate a very rapid rate of growth of the industrial load in the Upper Sind (Sukkur area) but a comparatively slow rate of growth in the North where it is assumed that industry would be predominantly concerned with processing agricultural commodities and producing consumer goods. The Bank Group's evaluation of Stone & Webster's projection of the regional distribution of industrial load suggests that it is reasonable, as far as can now be foreseen. A case could be made for a somewhat slower rate of load growth in Karachi and in the Northern Grid, especially in the early years, but the load growth in Upper Sind may be even more rapid than projected by the power consultant if sufficient investment in the nitrogenous fertilizer industry is made.

Detailed Evaluation of Industrial Consumption of Electricity

In evaluating the Stone & Webster load forecasts the Bank Group attempted to develop relationships between industrial value added (i.e. the gross output of an industry net of purchased inputs) and industrial consumption of electricity. An analysis was made of the present power-intensity of different industries in West Pakistan (i.e. kwh consumed per rupee of value added). With adjustments for any anticipated changes in the power-intensity of different industrial sectors, projections could then be made of the growth of industrial consumption of electricity that might be expected to accompany any particular pattern and rate of future industrial development.

The overall power intensity of industry in a country is heavily affected by the relative weight in total industrial production of a few industries which consume large quantities of power per unit of output. Aluminum, for instance, and paper, cement and certain chemicals tend to be very power-intensive, and the growth of industrial consumption of electricity will be greatly influenced by the pace at which such industries are growing.

In general, as might be expected, industrialized countries consume considerably more electrical energy per unit of value added in industry than do low and middle income countries. Table 2 shows some estimates recently made for a number of countries, on the basis of 1961 data, in terms of dollars of value added per kwh consumed in industry. Pakistan ranks quite low in this list at a level of $1.2 of value added per kwh consumed. The table is based on conversion into U.S. dollars at current official exchange rates.

Table 2

Industrial Consumption of Electricity in Selected Countries per dollar value added in industry, 1961
(kwh per $ value added)

Norway	16.1	Netherlands	2.2
Canada	7.0	West Germany	2.1
Finland	5.2	France	2.1
Spain	4.6	Iceland	2.0
U.S.S.R.	4.3	Greece	1.9
Australia	4.3	Morocco	1.9
Poland	4.2	Luxembourg	1.9
Japan	3.9	Philippines	1.8
U.S.A.	3.4	Puerto Rico	1.8
Mexico	3.4	Kenya	1.7
Italy	3.3	Ceylon	1.6
Belgium	3.2	Trinidad	1.5
Austria	3.1	Israel	1.5
Malaya	3.1	Cyprus	1.3
Syria	3.0	Costa Rica	1.2
Thailand	2.7	Pakistan	1.2
United Kingdom	2.5	Burma	1.2
Portugal	2.4	China (Taiwan)	1.1
Jamaica	2.3	Ecuador	1.1
		Denmark	0.9

The evidence presented below for West Pakistan suggests that power consumption per dollar of value added is significantly higher than the estimate for Pakistan in Table 2 would imply. However, no great significance can be attributed to this fact, the figures being based on quite different sources.

Existing Pattern of Industrial Consumption of Electricity

In order to obtain a better understanding of the actual composition of the industrial consumption of power in West Pakistan the Bank Group developed a table of industrial power intensities on the basis of information supplied by the Planning Commission and other material gathered by the power consultant. This table indicates the estimated amount of power consumed by each industrial sector in the base-year 1962/63 and the estimated output of each sector (in PRs million at factor cost). The table is given in detail as Appendix Table II and it is summarized here in Table 3.

Table 3

Estimated Industrial Value Added and Electricity Consumption, 1962/63

Sector	Value Added (PRs mln.)	Electricity Consumption (mln.kwh)	Power Intensity (kwh/PRs10 value added)
Sugar	187.8	29.177	1.55
Tobacco	45.0	3.989	0.89
Textiles (80%)	412.6	253.778	6.15
Board, Paper	22.9	7.331	3.20
Other Consumer Goods	501.6	91.236	1.82
Total Consumer Goods	1,169.9	385.511	3.30
Rubber	8.2	1.265	1.54
Fertilizers	42.2	136.640	32.38
Cement	53.0	148.112	27.95
Textiles (20%)	103.2	63.444	6.15
Cotton-ginning	117.3	5.472	0.47
Chemicals & Refining	85.9	15.412	1.80
Other Intermediates	78.3	25.572	3.26
Total Intermediates	488.1	395.917	8.10
Investment Goods	334.0	110.905	3.32
Total Large-scale Mfg.	1,992.0	892.333	4.48

The last column of Table 3 indicates the power-intensity of each industry in terms of kwh consumed per PRs 10 of value added. As expected, certain industries such as cement and fertilizer stand out as being extremely power-intensive, others such as paperboard, textiles and certain chemicals are moderately power-intensive, while other industries such as tobacco and cotton-ginning use relatively little electric power per unit of output. The relative order of magnitude of these results for different industries corresponds

approximately to what might be expected from other countries' industrial experience. There are some cases -- such as refining and some of the intermediate-good sectors -- where the power consumption figures seem unreasonably low and others where they are probably high.

On the whole, the figures of industrial consumption of electricity given in Table 3 seem considerably too low. The following table shows estimated sales of electric power to industrial consumers in the fiscal year 1962/63.

Table 4

Estimated Industrial Sales of Electricity and Self-Generation, 1962/63
(Million kwh)

WAPDA - Industrial Sales a/	664
Deduction: estimated consumption at dam sites	20
	644
KESC - Industrial Sales b/	208
Industrially owned generation c/	535
Other utilities' industrial sales c/	41
TOTAL	1,428

a/ Taken from WAPDA's annual reports, and including 30 million kwh for Wah.
b/ Interpolated from KESC's recorded sales (calendar-year basis).
c/ Estimates from the power consultant's report and Central Statistical Office, Census of Electricity Undertakings 1962/63.

There is a sizeable discrepancy between the estimates of total industrial consumption of electricity given in Tables 3 and 4. This is to be expected because Table 3 is based on results of surveys of industrial consumers while Table 4 is based on the accounts of the electric utilities, which are kept in a form which does not readily indicate the nature of the ultimate electricity consumer. The survey results may be underestimates, because power consumption figures have been used in Pakistan in the taxation of industrial enterprises. The estimates in Table 4 do cover several important classes of consumer not included in Table 3. The mining industry, for one, consumed at least 20 million kwh in 1962/63 (mainly self-generated). More important still, small-scale industry and numerous other semi-industrial establishments (such as sewerage and water supply pumping stations, Irrigation Department Workshops, airports, etc.) are covered by the figures given in Table 4 but not by those given in Table 3. Small-scale industry and other establishments probably account for 200 million kwh out of the total of 1,428 million kwh listed in Table 4 as industrial consumption in 1962/63.

Deduction of these items from estimated industrial consumption in 1962/63 leaves an estimate of 1,210 million kwh as consumption in the large-scale industrial sector in the base-year. This is still about 320 million kwh above the figure given in Table 3. It is likely that the

most serious undercounting in the survey figures occurs in the consumer goods sector, where there are many small industrial establishments. However, to make sure that our figures include an adequate allowance for the higher power intensity of the intermediate goods and capital goods sectors which are expected to grow more rapidly than consumer goods industries in coming years, we have distributed the difference of 320 million kwh in proportion to the recorded consumption of electricity of the various sectors. 1/ The following table summarizes the adjusted estimates of power-intensity by major industrial grouping, separating out from the intermediate goods sector the highly power-intensive nitrogenous fertilizer and cement industries.

Table 5

Large-Scale Manufacturing in West Pakistan
Estimated Power Intensities, 1962/63

	Value Added (PRs mln.)	Power Consumption (Million kwh) Reported	Adjusted	Power Intensity (kwh/PRs10 value added)
Capital Goods	334	111	151	4.52
Consumer Goods	1,170	386	525	4.49
Cement, Concrete	53	148	201	37.92
Nitrogen fertilizer	42	137	186	44.28
Other intermediates	393	111	151	3.84
	1,992	892	1,214	6.10

In order to check the validity of the sectoral power-intensity approach to the projection of the industrial load and to see how power-intensities of the major industrial groupings are changing, estimates were made of the sectoral growth of value added between 1962/63 and

1/ Even in the case of the nitrogenous fertilizer industry for which the recorded figures on electricity consumption are already inexplicably high. The Multan plant has a capacity of 59,000 tons of urea and 103,000 tons of calcium ammonium nitrate. The highest electricity consumption that could reasonably be expected for this plant, if it were working at full capacity, is about 76 million kwh (including an allowance for off-site facilities) -- or about 1,400 kwh per ton of nitrogen. Full capacity represents about 54,000 tons of nitrogen-equivalent fertilizer. Actual production was about 30,000 tons of nitrogen in 1962/63 when recorded power consumption was 77 million kwh, while in 1963/64 production was about 34,000 tons of nitrogen and recorded consumption of electricity about 101 million kwh. The Daudkhel ammonium sulphate plant has a capacity of 10,500 tons of nitrogen-equivalent fertilizer (50,000 tons of ammonium sulphate) and appears to have been running close to capacity in recent years. Anticipated electricity consumption at 500 kwh per ton of N would be 5.5 million kwh. The plant generates its own electricity and was estimated to have produced 54.0 million kwh in 1962/63.

1964/65. Consumption of electricity by major sectors was then estimated on the assumption that power-intensities of each individual industry remained the same. The detailed projection is presented in Appendix Table III and a summary for comparison with Table 5 follows:

Table 6

Large-Scale Manufacturing in West Pakistan
Estimated Power Intensities, 1964/65

	Value Added (PRs mln.)	Power Consumption (Million kwh) Estimated	Adjusted	Power Intensity (kwh/PRs10 value added)
Capital Goods	507	169	230	4.53
Consumer Goods	1,408	499	680	4.82
Cement, Concrete	56	156	212	37.90
Nitrogen fertilizer	29	93	126	44.30
Other intermediates	670	173	235	3.50
	2,670	1,090	1,483	5.55

The 'adjusted' column of figures in this table was derived by multiplying the figures estimated on the basis of growth of value added by the same ratio (1.36) as was used to gross up the figures for 1962/63.

Assuming constant power intensities in the mining and small industry sectors, consumption by these sectors would have been about 24 million kwh and 210 million kwh respectively in 1964/65. Addition of these to the 'adjusted' total in Table 6 would suggest that total industrial consumption of electricity in 1964/65 must have been about 1,717 million kwh.

Actual sales of the utilities to industry, together with industrial self-generation in 1964/65, are estimated as shown in Table 7.

Table 7

Estimated Industrial Sales of Electricity and Self-Generation, 1964/65
(Million kwh)

WAPDA - Industrial Sales a/	932
Deduction: estimated consumption at dam sites	120
	812
KESC - Industrial Sales b/	325
Industrially owned generation c/	544
Other utilities' industrial sales c/	45
TOTAL	1,726

a/ Footnote same as to Table 4.
b/ Footnote same as to Table 4.
c/ Footnote same as to Table 4.

Thus the two estimates of industrial consumption of electricity appear to check out quite well with one another. The difference between 1,717 and 1,726 is well within the margin of error.

Projection of Electricity Consumption in Cement and Fertilizer Industries

The cement and fertilizer industries were shown above to be very much more power-intensive than other industries in Pakistan, as elsewhere. For this reason and because both industries, particularly nitrogenous fertilizer production, are likely to grow quite rapidly in coming years, they were separated out and projected individually. Projections of production of cement and fertilizer were made on the basis of the Bank's report, "The Industrial Development of Pakistan" (June 7, 1966), and with due regard to conclusions reached in other parts of the Indus Special Study about fertilizer production and consumption. 1/

Detailed projections of fertilizer and cement production and electricity consumption by these industries are shown in Appendix Tables IV, V and VI. The physical levels of output projected for 1970 are not quite the same as those given in the Third Plan document in the case of cement; production is here projected at 3.5 million tons in 1970, as compared with the Third Plan target of 4.0 million tons. Nitrogenous fertilizer production is here projected at 250,000 tons of nigrogen equivalent, which is about the same as in the Third Plan document of June 1965. The shortfall in cement arises from delays that have been encountered in getting underway some of the projects which are to produce the expected output increases.

In Volume II of this report the Bank Group presents targets of fertilizer absorption which are substantially above those selected by the agriculture consultant, but somewhat below the targets adopted by the Government of Pakistan. If farmers do show a more rapid response to fertilizer than presently anticipated, and if the transport and fertilizer-distribution systems can be improved rapidly enough to handle much larger quantities, then it would be fully worthwhile to ensure that the requisite amount of fertilizer is available. The Bank Group's targets for the absorption of nitrogenous fertilizer are compared in Table 8 with the projection of nitrogenous fertilizer production assumed for purposes of this analysis of power requirements.

1/ See Volume II, Program for the Development of Irrigation and Agriculture.

Table 8

Production and Consumption of Nitrogenous Fertilizer
('000 tons nutrients)

	1965	1970	1975	1980	1985
Production a/	65	250	560	790	1,020
Consumption b/	90	250	470	540	620

a/ From Appendix Table V.
b/ From Volume II, p. 213.

Thus the production assumptions made here fully cover the consumption projected in Volume II. The objective here was to make ample allowance for any unanticipated growth in demand and also for the possibility that export of fertilizer will become attractive.

Requirements of electricity for production of fertilizer and cement are estimated in Appendix Table VI, which details the assumptions made. It is important to note that the effective power-intensity of fertilizer production will probably decline markedly in coming years, partly because the existing fertilizer plants appear to be consuming much greater quantities of electricity than modern equipment should require and partly because the large-scale fertilizer plants that are planned for the future should be able to meet a large proportion of their own energy requirements through the use of process steam. Table 9 summarizes the projection of electricity requirements for production of cement and fertilizer.

Table 9

Electricity Requirements for Production of Cement and Nitrogenous Fertilizers
(Million kwh)

	1965	1970	1975	1980	1985
Cement	212	520	700	960	1,320
Fertilizer	126	360	516	610	700

Industrial Growth in the Perspective Plan

The long-term growth framework provided by the Planning Commission and discussed in greater detail in the Economic Annex to this report implies that the West Pakistan gross provincial product will grow at an average rate a little above 6 percent per annum over the period 1965-85. Agriculture is expected to make a very substantial contribution to this overall growth rate. Large-scale industry is expected to grow at an average rate of about 8 percent or, in other words, only slightly more rapidly than the total provincial product. This would be a reversal of the situation during the Second Plan

period (1960-65) when the industrial sector grew substantially faster than gross provincial product. Constant-price estimates suggest that between 1959/60 and 1964/65 gross provincial product grew at an average rate of nearly 6 percent per annum, output of the manufacturing sector at about 11.5 percent per annum, and output of the large-scale manufacturing sector at about 16 percent per annum.

Despite the apparent undue pessimism of the Perspective Plan with regard to the industrial growth rate in West Pakistan, an initial projection of industrial power load was made, consistent with the specific projections made above for cement and fertilizer and with a framework of industrial growth which was believed to be compatible with the expectations of the Planning Commission. This framework is presented in detail in Appendix Table VII. It was found that industrial consumption of electricity might, on this basis, be expected to grow from about 1,720 million kwh in 1964/65 to about 3,800 million kwh in 1974/75, and about 7,700 million kwh in 1984/85 -- or, in other words, at an average rate of about 7.8 percent per annum, slightly more before 1975 and slightly less afterwards.

This projection was made on the assumption of constant power-intensities in all sectors except fertilizer. Power consumption had been projected on the basis of the highly aggregated sectors (shown in Appendix Table VII) such as consumer goods manufacturing, capital goods, small industry, etc. There appeared to be no particular reason for anticipating a substantial increase of power-intensity in the capital-goods and consumer-goods sectors. Major capital-goods industries are expected to be established in West Pakistan, including heavy electrical machinery, textile machinery and transport equipment but the ratio of value added to consumption of electrical energy tends to be relatively high in those industries, and the overall power-intensity of the sectors might decline slightly rather than increase. In the intermediate goods sector, on the other hand, some major industries are expected to come into Pakistan which are qualitatively different from existing plants in this sector in the Province. Table 3 showed that the average power-intensity in the intermediate goods sector excluding fertilizer and cement is at present exceptionally low. This results mainly from the predominant position of the cotton-ginning industry in the sector and from the fact all the other industries in the sector have comparatively low power requirements. Two important additions to this sector which will be undertaken during the next ten years will be considerably more power-intensive.

Petrochemical Industry

A very ambitious plan has been prepared by consultants for the construction of a major petrochemical industry in West Pakistan, concentrated in the Karachi area. This petrochemical complex would be based, in the first instance, on a naphtha cracker producing naphtha and ethylene. The Bank's industrial mission has endorsed the project and recommended that West Pakistan concentrate its efforts in the petrochemical field on products that can be made as

derivatives of the steam cracking unit. Stone & Webster have made an allowance for the power requirements of the petrochemical complex, considerably smaller than the projections that had been made by others but more in line with the actual likely growth of the petrochemical industry and rising to substantial levels in later years. The most recent information available to the Bank Group on this project is presented in Appendix Table VIII. The Stone & Webster allowance for the electricity requirements of the petrochemical complex is somewhat below the estimates given there for the early period and somewhat above them for later years.

Steel Industry

Another major potential development in the intermediate goods sector which could substantially affect sectoral electricity consumption is the construction of one or possibly two steel mills. A steel mill at Karachi has been under consideration for more than a decade. Due to delays in the early years of the Third Plan it will not be possible to have this plant completed by 1970. One plan is for a mill based on electric arc furnaces which would use local and imported scrap to produce billets, rails, tubes and sheets. Capacity would be in the neighborhood of half a million tons of finished product per annum. If the plant comes into operation in Karachi in the early 1970's, as presently projected, its large power requirements will be too fluctuating for it to be dependent entirely on KESC. However KESC would probably supply a gradually increasing proportion of its requirements. A further possible development in this sector is establishment of a steel mill based on local ore at Kalabagh. West German consultants have suggested that the Kalabagh ore might be recovered economically, despite its low ferrous content, by application of a new process. Implementation of either of these projects still remains a matter of uncertainty at present, but some allowance should be made for their potential power requirements in the slightly longer term.

Estimates of the power requirements of these two industries, based mainly on the views of Stone & Webster, are given in Table 10.

Table 10

Energy Requirements of Petrochemical Complex and Steel Mills
(Million kwh)

	1970	1975	1980	1985
Petrochemical complex	360	560	780	1,390
Karachi steel mill	-	100	400	800
Kalabagh steel mill	-	150	300	600
TOTAL	360	810	1,480	2,790

Formal consistency would require some compensating reduction in the industrial load forecasts made on the basis of constant power-intensity before these loads are included as allowance for extreme power-intensity of anticipated new plants. However the contribution of the "Other intermediates" sector (i.e. intermediate goods excluding fertilizer and cement), in which grouping these industries fall, to the load forecast is relatively small and the power-intensity upon which it is based is so low that it seems permissible simply to add these loads to those derived on the macro-economic base.

"Perspective Plan" Industrial Load Forecast

Addition of these special loads to those derived on the basis of the Perspective Plan framework would lead to estimates of about 4,600 million kwh in 1975 and about 10,500 million kwh in 1985 for the industrial consumption of electricity. Comparison of these figures with those given in Table 1 indicates that the estimates derived from the Perspective Plan are substantially below those made by Stone & Webster.

A Higher Industrial Growth Rate?

As pointed out above, the industrial growth rate implicit in the Perspective Plan seems low by comparison with past performance in West Pakistan. Some elements of the growth pattern -- such as the very low rate of growth projected in the consumer goods industry -- also seemed to represent projections from which there might in practice be some divergence. Therefore it appeared useful to test the implications of an alternative forecast of industrial growth in West Pakistan. This pattern, which differs from the "Perspective Plan" growth-path primarily by allowing more rapid growth of consumer-goods industries and hence of overall industrial production, is shown in Table 11. The lower half of the table indicates the power requirements, which this pattern of industrial development would imply, assuming constant power-intensities (except in the case of fertilizer).

Addition to the totals in Table 11 of appropriate allowances for the growth of mining and of small industry and for the special petrochemical and steel projects discussed in previous paragraphs leads to the estimate of the growth of industrial consumption of electrical energy presented in Table 12.

Table 11

Large-Scale Manufacturing Industry, 1965-85 a/
(PRs million, 1962/63 prices)

	1965		1970		1975		1980		1985
Capital goods	507	(20.0)	1,250	(14.2)	2,450	(10.7)	4,050	(8.9)	6,200
Consumer goods	1,408	(6.0)	1,900	(6.0)	2,550	(5.5)	3,300	(5.5)	4,300
Intermediate goods	755	(16.3)	1,600	(15.0)	3,230	(10.0)	5,200	(8.9)	8,000
Of which:									
Fertilizer (nitro)	29		157		345		487		640
Cement	56		116		158		216		310
Other intermediates	670		1,327		2,727		4,497		7,050
TOTAL	2,670	(12.2)	4,750	(11.6)	8,230	(8.8)	12,550	(8.0)	18,500

Electricity Consumption
(Million kwh)

Capital goods	230		566		1,110		1,840		2,810
Consumer goods	680		920		1,230		1,600		2,100
Fertilizer (nitro)	126		360		516		610		700
Cement	212		520		700		960		1,320
Other intermediates	235		460		950		1,570		2,460
TOTAL	1,483	(13.7)	2,826	(9.8)	4,506	(8.0)	6,580	(7.5)	9,390

a/ Figures in brackets represent annual growth rates of the relevant sectors during the Plan periods in which they are inserted.

Table 12

Projected Industrial Requirements for Electrical Energy with High Industrial Growth Rate
(Million kwh)

	1965	1970	1975	1980	1985
Large-scale industry	1,483	2,826	4,506	6,580	9,390
Steel and Petrochemicals	-	360	810	1,480	2,790
Mining	24	40	60	90	130
Small industry, etc. a/	210	234	274	370	490
TOTAL	1,717	3,460	5,650	8,520	12,800
Stone & Webster Forecast b/	1,815	3,403	6,079	9,410	13,562

a/ With allowance for increasing conversion to power-driven equipment in later years of the Perspective Plan.
b/ Excluding power for dam sites.

Conclusion

In very general terms, the conclusion to be drawn from the Bank Group's analysis is that the Stone & Webster forecast of industrial load may be somewhat on the high side for most of the period under study. The rapid rate of growth projected by Stone & Webster for the Third Plan period may be attained, if progress is as rapid as here assumed, particularly in the power-intensive industries such as nitrogenous fertilizer, petrochemicals and cement. Thus, during the Third Plan, total industrial consumption of electricity may well grow more rapidly than total industrial output -- in contrast to the Second Plan period when total industrial load appears to have grown about 10 percent per annum and industrial output (including small industry) about 13 percent per annum. During the Fourth Plan period the growth of industrial demand for electricity may slow down somewhat as the growth of industry stabilizes and agriculture grows more rapidly, and as some of the most power-intensive industries (such as fertilizer) take advantage of modern techniques which involve much less purchase of electricity from outside and much more generation from process steam. The same trend might continue through the Fifth Plan period.

Regional Distribution of Load Growth

As regards the regional distribution of the load growth the 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 area where it is at present larger, the North. The main reasons for this are that there are few power-intensive industries presently foreseeable in the North; Karachi, on the other hand, 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 complex industry; the Sind has the advantage of its extensive natural gas resources -- and also 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 typically 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.

Within the South itself there might be some redistribution of the loads projected by Stone & Webster. For instance, they allow a growth of industrial load in Upper Sind barely sufficient to meet the demands for purchased power that may arise from the fertilizer industry there. On the other hand, they have 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 economics make it mandatory to locate production on the gas field itself. The petrochemical load which Stone & Webster project for Karachi appears a little high for the 1980's in comparison with some of the more detailed planning undertaken more recently (see Appendix Table VIII). On the other hand, latest plans do envisage some railroad electrification in the South which would add a small load not included in the Stone & Webster load forecast (see Appendix Table IX).

Though the evidence available at present suggests that Karachi and the South will continue to increase their share of the total Provincial industrial load, it will be necessary to keep the likely regional distribution of loads as well as their overall magnitude under close surveillance. As pointed out in Chapter I the regional pattern of load growth has important implications for some expensive investments in transmission. There are forces at work which could swing the balance of industrial load growth more in favor of the North -- for instance the growing shortage of water in the Karachi area, the possibility of significant industrial development around Kalabagh and Daudkhel -- and so it would be unwise to be too categorical on this matter.

Appendix Table I

The Stone & Webster Industrial Load Forecast a/
(Million kwh)

	Estimated Actuals					Forecasts					Average Annual Rate of Growth 1965-85
	1960	1961	1962	1963	1964	1965	1970	1975	1980	1985	%
Northern Grid b/	427	480	565	617	682	820	1410	2270	3480	5030	9.5
Upper Sind	-	1	1	1	1	10	145c/	220d/	300	409	20.0
Lower Sind	14	20	32	47	65	83	204	420	720	1130	14.0
Karachi	110	127	161	217	286	355	850	1750	2950	4440	13.5
Quetta	-	-	-	-	-	3	14	24	40	60	16.1
Other Utilities e/	28	28	28	28	28	-	-	-	-	-	-
Self-generation	520	530	535	535	537	544	650	915	1000	1103	3.6
Petrochemical complex	-	-	-	-	-	-	130	480	920	1390	
TOTAL	1099 (8)	1186 (12)	1322 (9)	1445 (11)	1599 (14)	1815 (13)	3403 (12)	6079 (9)	9410 (8)	13,562	10.5

a/ Figures in brackets are annual rates of growth in percentages.
b/ 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.
c/ Estimate assumes WAPDA would serve Esso fertilizer plant in 1970 with 100 million kwh at maximum load of 15 mw.
d/ Forecast based on power consultant's anticipation of substantial expansion in the fertilizer, cement, textiles and food processing industries.
e/ For the years 1960 through 1964 the regional distribution is given only for the estimated industrial sales of WAPDA and KESC; energy used for industrial purposes and generated by other utilities or by the industries themselves is listed separately. The figures for 1965 and subsequent years include all utility sales and a certain amount of energy demand that will accrue as firms give up generating their own power and transfer to the utilities.

Appendix Table II

Consumption of Electricity by Industrial Sector, 1962/63

Sector	Value Added (Factor Cost) PRs mln.	Electricity Consumption (Millions of kwh) Purchased	Self-generated	Total	kwh per PRs 10 Value Added
Food					
Canning & Preserving	3.2	0.122	-	0.122	0.38
Grain Milling	36.9	8.753	-	8.753	2.36
Bakery Products	13.9	0.808	-	0.808	0.58
Sugar Mills	187.8	1.811	27.366	29.177	1.55
Edible Oils, etc.	56.2	23.244	7.789	31.033	5.52
Tea Processing	12.9	0.192	0.001	0.193	0.15
Salt	5.7	0.120	-	0.120	0.21
Total	316.6	35.050	35.156	70.206	2.22
Beverages					
Alcoholic Beverages	3.5	0.848	-	0.848	2.42
Non-alcoholic Beverages	21.4	1.935	-	1.935	0.90
Total	24.9	2.783	-	2.783	1.12
Tobacco	45.0	3.879	0.110	3.989	0.89
Textiles					
Cotton Textiles	404.1	169.706	127.136	296.842	7.35
Woolen Textiles	25.7	11.832	1.018	12.850	4.99
Silk, Art Silk	33.2	4.836	0.930	5.766	1.74
Dyeing & Printing	20.3	0.636	-	0.636	0.31
Knitting	14.4	0.156	-	0.156	0.11
Thread, Threadball	6.5	0.554	-	0.554	0.85
Textiles, n.e.s.	11.6	0.418	-	0.418	0.36
Total	515.8	188.138	129.084	317.222	6.15
Clothing, etc.					
Footwear	2.2	5.933	-	5.933	27.00
Wearing Apparel	5.3	0.046	-	0.046	0.09
Fabricated Textiles	7.2	0.090	-	0.090	0.13
Total	14.7	6.069	-	6.069	4.13
Furniture, etc.					
Wood, Cork Products	1.2	0.195	-	0.195	1.63
Wood Furniture	3.8	0.099	-	0.099	0.26
Metal Furniture	0.9	0.051	-	0.051	0.57
Total	5.9	0.345	-	0.345	0.58

Appendix Table II (continued)

Sector	Value Added (Factor Cost) PRs mln.	Electricity Consumption (Millions of kwh) Pur-chased	Self-generated	Total	kwh per PRs 10 Value Added
Paper & Printing					
Board, Paper Products	22.9	7.331	-	7.331	3.20
Printing & Publishing	39.6	1.458	-	1.458	0.37
Total	62.5	8.789	-	8.789	1.40
Leather					
Tanning	50.1	0.795	-	0.795	0.16
Leather Products	2.0	0.028	-	0.028	0.14
Total	52.1	0.823	-	0.823	0.16
Rubber					
Tires & Tubes	3.7	0.855	-	0.855	2.31
Other Rubber Products	4.5	0.410	-	0.410	0.91
Total	8.2	1.265	-	1.265	1.54
Chemicals					
Fertilizers	42.2	82.500	54.140	136.640	32.38
Paints & Varnishes	21.2	3.505	-	3.505	1.65
Perfumes, Soaps, etc.	8.4	0.271	7.720	70.991	9.50
Matches	0.2	0.142	-	0.142	7.10
Med. & Pharm. Chemicals	83.2	11.643	0.219	11.862	1.42
All Other Chemicals	80.5	3.679	5.330	9.009	1.12
Non-edible Vegetable Oils	5.9	2.956	1.278	4.234	7.17
Total	241.6	104.696	68.687	173.383	7.18
Oil Refining	53.2	3.357	8.393	11.750	2.20
Non-Metal Minerals					
Glass, Pottery Earthenware	9.6	1.860	0.573	2.433	2.53
Cement, Concrete Products	53.0	32.810	115.302	148.112	27.95
Non-metal Minerals, n.e.s.	8.9	0.164	5.325	5.489	6.17
Total	71.5	34.834	121.200	156.034	21.84
Iron & Steel	58.0	12.965	0.706	13.671	2.36
Metal Goods	101.7	12.353	-	12.353	1.21
Machinery					
Agricultural Machinery	21.1	2.865	-	2.865	1.36
Engines, Turbines	14.2	1.232	-	1.232	0.87
Other Non-electrical Mach.	70.6	43.762	18.259	62.021	8.78
Total	105.9	47.859	18.259	66.118	6.24

Appendix Table II (continued)

Sector	Value Added (Factor Cost) PRs mln.	Electricity Consumption (Millions of kwh) Pur-chased	Self-generated	Total	kwh per PRs 10 Value Added
Electrical Goods	48.5	5.898	-	5.898	1.22
Transp. Equipment	108.4	8.392	21.850	30.242	2.79
Miscellaneous Manufacturing					
Surgical Instruments, etc.	8.1	0.391	-	0.391	0.48
Plastic Products	22.1	0.041	-	0.041	0.02
Sports Goods	2.5	0.091	-	0.091	0.36
Ice-manufacture	1.8	3.359	0.620	3.979	22.11
Cotton-ginning	117.3	3.849	1.623	5.472	0.47
Pens, Pencils, etc.	5.7	1.164	0.255	1.419	2.48
Total	157.5	8.895	2.498	11.393	0.72
GRAND TOTAL	1,992.0	486.390	405.943	892.333	4.48

Appendix Table III

Estimated Industrial Value Added and Electricity Consumption

	Value Added a/ (Million PRs)			Electricity Consumption (Million kwh)	
	1962/63	1964/65	Index	1962/63	1964/65
Consumer Goods					
Sugar	187.8	135.0	72	29.177	21.007
Tobacco	45.0	62.0	138	3.989	5.505
Textiles (80%)	412.6	568.0	138	253.778	350.214
Board, Paper	22.9	27.0	134	7.331	9.824
Other Consumer Goods	501.6	616.0	123	91.236	112.220
Subtotal	1,169.9	1,408.0		385.511	498.770
Intermediate Goods					
Rubber	8.2	6.3	77	1.265	0.974
Fertilizers	42.2	28.7	68	136.640	92.915
Cement	53.0	55.5	105	148.112	155.517
Textiles (20%)	103.2	142.0	138	63.444	87.553
Cotton-ginning	117.3	206.0	176	5.472	9.631
Chemicals & Refining	85.9	187.0	218	15.412	33.598
Other Intermediates	78.3	129.5	165	25.572	42.194
Subtotal	488.1	755.0		395.917	422.382
Investment Goods	334.0	507.0	152	110.905	168.576
TOTAL MANUFACTURING	1,992.0	2,670.0		892.333	1,089.728
Power Consumption x 136 b/				1,210.0	1,480.0
Mining	110.5	134.0	121	20.0	24.0
Small Industry, etc.	1,020.0	1,071.0	105	200.0	210.0
TOTAL INDUSTRIAL POWER CONSUMPTION				1,430.0	1,714.0

a/ Estimated on the basis of the national income accounts, data on the growth of physical production of certain important commodities given in the CSO Monthly Statistical Bulletin (mainly Central Board of Revenue figures), a paper by Wouter Tims, "Industrial Production in West Pakistan 1959/60-1962/63" (May 27, 1966), the Irrigation & Agriculture Consultants' estimates of the growth of agricultural production (for agricultural processing industries), and data on the index of manufacturing production provided by the Planning Commission. Estimates are in 1962/63 prices.

b/ 1964/65 power consumption by large-scale industry grossed up in the same proportion as was necessary to gross up recorded industrial consumption in 1962/63 to cover the estimated total supply.

Appendix Table IV

Projection of Cement Production a/
('000 long tons)

	1966	1967	1968	1969	1970	1975	1980	1985
Karachi	400	400	400	400	400	560	780	1,110
Hyderabad	540	1,140	1,140	1,140	1,140	1,490	2,100	2,940
Rohri	100	100	100	100	100	130	180	260
Daudkhel	250	250	250	250	250	250	250	250
Dandot	54	54	54	54	54	50	50	50
Wah-Hattar-Sangjani	560	560	680	800	800	1,120	1,560	2,200
Gharibwala	360	540	540	540	540	760	1,060	1,490
Kohat	180	180	180	180	180	250	350	500
TOTAL	2,444	3,224	3,344	3,464	3,464	4,610	6,330	8,800

a/ Increases after 1970/71 are at an average rate of 7 percent per annum except in the case of the Daudkhel and Dandot plants which are held constant.

Appendix Table V

Projection of Nitrogenous Fertilizer Production
('000 long tons of Nitrogen)

		1966	1967	1968	1969	1970	1971	1972	1976	1983
Existing Capacity & Planned Expansion										
Daudkhel:	Ammonium Sulphate (1 ton $(NH_4)_2SO_4$ = 0.21 ton N)	10.5	10.5	10.5	19.0	19.0	19.0	19.0	19.0	19.0
Multan:	Calcium Ammonium Nitrate (1 ton $NH_4NO_3 + CaCO_3$ = 0.26 ton N)	26.8	26.8	42.4	42.4	42.4	42.4	42.4	42.4	42.4
	Urea (1 ton $CO\ N_2H_4$ = 0.46 ton N)	27.2	27.2	27.2	34.0	34.0	34.0	34.0	34.0	34.0
Planned New Capacity										
Mari-Esso:	Urea (1 ton $CO\ N_2H_4$ = 0.46 ton N)	-	-	40.0	80.0	80.0	80.0	80.0	80.0	80.0
Daudkhel:	Ammonium Sulphate Nitrate (1 ton $(NH_4)_2\ SO_4 \cdot NH_4\ NO_3$ = 0.26 ton N)					78.0	156.0	156.0	156.0	156.0
Kandkhot:	Urea						115.0	230.0	230.0	230.0
Mari/Sui:	Urea								230.0	460.0
		64.5	64.5	120.1	175.4	253.4	446.4	561.4	791.4	1,021.4

Appendix Table VI

Projections of Electrical Energy Requirements of Major Power-Consuming Industries
(Million kwh)

	1966	1967	1968	1969	1970	1971	1972	1975	1976	1980	1983	1984	1985
Northern Area													
Nitrogenous fertilizer (Multan & Daudkhel)													
- Existing a/	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
- Extensions b/			20.2	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7
New fertilizer capacity (Daudkhel)					65.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Cement (Daudkhel, Dandot, Wah, Gharibwal, Kohat) c/	210.6	237.6	255.6	273.6	273.6	290.6	308.6	369.6	392.6	499.3	598.1	635.0	674.5
Upper Sind													
Nitrogenous fertilizer (Mari, Kandkhot) d/	-	-	50.0	100.0	100.0	146.0	192.0	192.0	284.0	284.0	376.0	376.0	376.0
Cement (Rohri) c/	15.0	15.0	15.0	15.0	15.0	15.0	16.0	21.0	22.5	27.6	33.8	36.1	38.7
Lower Sind													
Cement (Hyderabad) c/	81.0	171.0	171.0	171.0	171.0	171.0	183.0	224.2	239.9	314.3	385.1	412.2	441.0
Karachi													
Cement c/	60.0	60.0	60.0	60.0	60.0	64.2	68.7	84.2	90.1	118.0	144.6	154.7	165.5

a/ Taken as recorded for recent years.

b/ Power consumption rates used all include a 10% allowance for offices, cranes, packing facilities, workers' colony, etc.:

Ca. Amm. Nitrate:	340 kwh/ton of fertilizer or	1,300 kwh/ton of nutrient.
Amm. Sulphate:	100 kwh/ton of fertilizer or	500 kwh/ton of nutrient.
Urea:	630 kwh/ton of fertilizer or	1,500 kwh/ton of nutrient.
Amm.Sulph.Nitr.:	220 kwh/ton of fertilizer or	850 kwh/ton of nutrient.

c/ Power requirements for cement taken at the rate of 150 kwh per ton in order to make ample allowance for production of by-products, and for offices, workers' colony, conveyance systems, packaging, etc. This figure is in line with our final estimate of the current consumption of electricity per ton of cement produced.

d/ The projected Esso plant at Mari is included at a consumption of 100 million kwh p.a. This seems high but it is the figure given by the power consultant. The Kandkhot plant and subsequent large plants at Mari are assumed to use steam drivers making use of steam which is produced necessarily in the course of fertilizer-manufacture. Their energy consumption would thus be only about 400 kwh/ton N produced.

Appendix Table VII

"Planning Commission" Projection of Industrial Growth in West Pakistan, 1965-85 a/

(Million Rupees, 1959-60 prices)

	1965		1970		1975		1980		1985
Large-scale Industry									
Capital goods	348	(16.3)	741	(14.1)	1,433	(12.9)	2,628	(12.7)	4,777
Consumer goods	1,236	(4.3)	1,528	(2.9)	1,759	(3.0)	2,039	(3.0)	2,363
Cement & cement products	83	(16.7)	176	(6.5)	241	(6.5)	330	(6.5)	452
Nitrogen fertilizer	73	(30.0)	272	(25.0)	824	(7.4)	1,178	(5.4)	1,531
Other intermediates	696	(6.7)	964	(8.4)	1,434	(10.0)	2,305	(7.0)	3,224
Subtotal	2,437	(8.6)	3,681	(9.3)	5,691	(8.3)	8,480	(7.8)	12,347
Mining	132	(9.9)	211	(8.4)	317	(8.4)	476	(7.6)	687
Small Industry, etc.	1,030	(2.6)	1,171	(2.6)	1,332	(2.6)	1,514	(2.6)	1,721
TOTAL	3,599	(7.0)	5,063	(7.7)	7,340	(7.4)	10,470	(7.1)	14,755

a/ Figures in brackets represent annual growth rates of the relevant sectors during the Plan periods in which they are inserted.

Appendix Table VIII

Power Requirements of Proposed Petrochemical Complex at Karachi

		Production Capacity (Tons/year)	Power Consumption (kwh/ton product)	Total Consumption (Million kwh/year)
A.	Sanctioned Plants to be commissioned by 1967-68			
	Plant			
1.	Acetylene production	5,800	2,350	13.65
2.	Hydrocyanic acid production	4,000	1,000	4.00
3.	Methylacrylate production	700	240	0.17
4.	Acrylonitrile production	5,000	200	1.00
5.	Polyacrylonitrile fibre production	5,000	2,000	10.00
6.	Vinylchloride production	5,500	113	0.62
7.	Polyvinylchloride production	5,000	420	2.10
8.	Polyethylene production	5,000	1,950	9.75
9.	Polyester fibre production	3,500	3,767	13.20
10.	B.H.C.(50% W.P.) production	4,500	383	1.72
11.	D.D.T.(50% W.P.) production	2,500	3,000	7.50
12.	Methanol production	3,000	1,600	4.80
13.	Formaldehyde production	5,100	30	0.15
14.	Ureaformaldehyde resins production	2,150	325	0.70
	TOTAL			69.36

Energy requirement 69.36×10^6 kwh
Power demand at 90% load factor = 8,000 kw

B.	Recommended Production Capacity to be commissioned by 1969-70			
1.	Steam Cracking	160,000 light naphtha/year - 65,000 tons ethylene at 70% P.F.	2,000	91.00
2.	Acetylene production	5,800	2,350	13.60
3.	Hydrocyanic acid production	4,500	1,000	4.50
4.	Butadiene production	20,000	550	11.00
5.	Carbon black production	6,000	500	3.00
6.	Vinylchloride production	11,000	113	1.24
7.	Polyvinylchloride production	10,000	420	4.20
8.	Acrylonitrile production	5,800	200	1.16
9.	Methylacrylate production	700	240	0.17
10.	PACN fibre production	5,000	2,000	10.00
11.	Methylmethacrylate production	2,000)	1,100	4.30
12.	Polymethylenethacrylate production	1,900)		
13.	Polyethelene production	15,000	1,950	29.25
14.	Ethanol production	10,000	57	0.57
15.	Ethylene oxide production	6,000	2,470	14.80
16.	Ethylene glycol production	5,000	2,470	12.30
17.	Styrene production	15,000	212	3.18
18.	Polystyrene production	10,000	400	4.00
19.	Polypropylene production	6,000	1,150	6.90

Appendix Table VIII (continued)

B.	Recommended Production Capacity to be commissioned in 1969-70 (continued) Plant	Production Capacity (Tons/year)	Power Consumption (kwh/ton product)	Total Consumption (Million kwh/year)
20.	Isopropylalcohol production	10,000	250	2.50
21.	Glycerine production	6,000	800	4.80
22.	As-polybutadiene production	8,000	555	4.44
23.	Strenebutadiene rubber production	17,000	700	11.90
24.	Phthalic oxlydride production	5,000	1,000	5.00
25.	Terephthalic acid production	4,500	800	3.60
26.	Polyester fibre production	5,000	3,767	18.80
27.	B.H.C. production (50% WP) prod.	4,000	383	1.53
28.	D.D.T. production (50% WP) prod.	2,000	3,000	6.00
29.	Alkali electrolysis (chloxine) prod.	15,000	3,580	53.60
30.	Methanol production	20,000	1,600	32.00
31.	Formaldehyde production	20,000	30	0.60
32.	Ureaformaldehyde resins production	5,000	325	1.62
	TOTAL			361.56

Energy requirements 361.56×10^6 kwh
Power demand at 90% load factor = 46 mw
all in production in 1969-70.

C.	Recommended Production Capacity to be commissioned by 1980			
1.	Steam cracking	250,000 light naphtha - 65,000 ethylene	2,000 for ethylene	131.00
2.	Aromatic production	68,500	350	23.97
3.	Acetylene production	12,000	2,350	28.20
4.	Hydrocyanic acid production	8,000	1,000	8.00
5.	Butadiene production	30,000	550	16.50
6.	Carbon black production	10,000	500	5.00
7.	Vinylchloride	22,000	113	2.48
8.	Polyvinylchloride production	20,000	420	8.40
9.	Acrylonitrile production	12,000	200	2.40
10.	Methylmeacrylate production	1,500	240	0.36
11.	Polyacrylonitrile fibre production	10,000	2,000	20.00
12.	Methylmetacrylate production	3,200)	1,100	6.82
13.	Polymethylmeacrylate production	3,000)		
14.	Polyethylene production	30,000	1,950	58.50
15.	Ethanol production	15,000	57	0.86
16.	Ethylene oxide production	7,000)	2,470	37.05
17.	Ethylene glycol production	8,000)		
18.	Ethanolamies production	2,000	330	0.66
19.	Styrene production	20,000	212	4.24
20.	Polystyrene production	12,000	400	4.80
21.	Polypropylene production	12,000	1,150	13.80
22.	Isopropylalcohol production	15,000	250	3.75
23.	Glycerine production	10,000	800	8.00
24.	As-polybutadiene production	10,000	555	5.55

Appendix Table VIII (continued)

C.	Recommended Production Capacity to be commissioned by 1980 (continued)	Production Capacity (Tons/year)	Power Consumption (kwh/ton product)	Total Consumption (Million kwh/year)
25.	Styrene butadiene rubber prod.	25,000	700	17.50
26.	Phtalic anhydride production	10,000	1,000	10.00
27.	Terepthalic acid production	10,000	800	8.00
28.	Polyester fibre production	10,000	3,767	37.67
29.	Polyester resins production	10,000	100	1.00
30.	Cydohexanol production	22,000	1,660	36.52
31.	Phenol production	8,000	312	2.49
32.	Caprolactain production	10,000)	1,660	31.54
33.	Hydroxylamin sulphate production	9,000)		
34.*	Nylon-6 fibre production	10,000	11,700	117.00
35.	B.H.C. 50% W.P. production	4,000	383	1.53
36.	D.D.T. 50% W.P. production	2,000	3,000	6.00
37.	Alkali electrolysis prod.(chlorine)	15,000	3,580	53.70
38.	Formaldehyde production	35,000	30	1.05
39.	Methanol production	35,000	1,600	56.00
40.	Phenol-Formaldehyde resin prod.	10,000	620	6.20
41.	Urea-formaldehyde resin prod.	10,000	325	3.25
42.	Ethlether production	1,000	125	0.12
43.	Methylenechloride production	1,000	1,400	1.40
44.	Hexamethylenterramin production	1,500	427	0.64
45.	Pentacrythirtol production	2,000	1,000	2.00
	TOTAL			783.95

* Without Nylon Plant: 666.95

Total energy requirement with Nylon Plant	783.95 x 10^6 kwh
Average demand at 90% load factor	100 mw
Total energy requirement without Nylon Plant	666.95 mln.kwh
Average demand at 90% load factor	85 mw

Source: Karachi Electric Supply Corporation

Appendix Table IX

Railway Electrification Plans

Station From	Station To	Distance miles		Peak Demand mw	Energy kwh x 10^6	Year of Commission
(1) Lahore	Khanewal	152 25	ST* DT*	20	55	Dec. 1969
		Total	202 ST			
(2) Lahore	Rawalpindi	172 7	ST DT	20	60	Fourth Plan
		Total	184 DT			
(3) Karachi	Kotri	115	DT	20	52	Fifth Plan
		Total	230 ST			
(4) Sibi	Quetta	64	ST	20	45	Sixth Plan

Note: Planning of items (2), (3) and (4) has not been approved. It is under consideration.

*ST means Single Track.
*DT means Double Track.

Source: WAPDA and Railways Board.

ANNEX 3

THE RESIDENTIAL LOAD FORECAST

THE RESIDENTIAL LOAD FORECAST

Table of Contents

THE RESIDENTIAL LOAD FORECAST

Stone & Webster Residential Load Forecast

Stone & Webster forecast that the residential load met by the power utilities in West Pakistan will increase at an average rate of about 12 percent per annum from 380 million kwh in 1965 to 3,700 million kwh in 1985. The residential load as a proportion of total utility sales would increase slightly from about 14 percent in 1965 to about 15 percent in 1985. The most significant growth, in absolute terms, would occur in the urban areas, where the residential load would increase from 343 million kwh in 1965 to over 3,000 million kwh in 1985; but the rate of growth would be much higher in rural areas, where total residential load would increase from about 40 million kwh in 1965 to nearly 700 million kwh in 1985 (see table below). Growth would be particularly rapid in the Sind, where the residential load is at present very small.

Table 1

Power Consultant's Residential Load Forecast
(Million kwh)

	1965	1970	1975	1980	1985	Implied Annual Rate of Growth %
North						
Urban a/	207.0	364.0	616	1,012	1,600	10.7
Rural	36.0	98.0	217	370	580	14.9
Upper Sind						
Urban a/	4.8	10.4	21	41	69	14.2
Rural	1.3	4.6	13	29	53	20.3
Lower Sind						
Urban a/	14.7	31.0	58	105	173	13.1
Rural	1.3	4.0	9	22	43	19.1
Baluchistan						
Urban a/	5.6	10.1	19	31	51	11.7
Rural	0.2	0.5	2	5	11	22.1
Karachi						
Urban a/	111.0	204	370	655	1,120	12.3
TOTAL	382 (13.7)	727 (12.8)	1,325 (11.4)	2,270 (10.3)	3,700	12.0
Total Urban	343	620	1,084	1,844	3,013	11.5
Total Rural	39	107	241	426	687	14.6

a/ "Urban" is defined by Stone & Webster as including those places which were cited by the 1961 Census as having a population in excess of 25,000 in 1961.

Growth of the residential load would generally be more rapid in the early part of the 20-year period and would tail off towards the end (see the more detailed summary of the Stone & Webster Residential Load Forecast in Appendix Table 1). Average annual consumption per house would rise from an estimated 420 kwh in 1965 (about 600 in urban areas and 100 in rural areas) to about 750 kwh in 1985 (about 1,300 in urban areas and 250 in rural areas). The proportion of the total population electrified would rise from an estimated 10 percent at present (35 percent in urban areas and 5 percent in rural areas) to about 35 percent in 1985 (55 percent in urban areas and 25 percent in rural areas).

This large increase in the domestic supply of electricity will involve very substantial investments in distribution. Stone & Webster estimate the number of connections implied by their load forecast as follows:

Table 2

Projection of Residential Electricity Connections a/
('000)

	1965 estimated existing	1970	1975	1980	1985
North - Urban	290	407	571	786	1,071
- Rural	234	500	864	1,257	1,653
Sind - Urban	27	36	72	112	162
- Rural	16	43	86	164	264
Baluchistan	10	16	29	46	69
Karachi	89	135	200	287	400
TOTAL	666	1,137	1,822	2,652	3,619
Average yearly increase		94	137	166	193

a/ Calculated from the power consultant's load forecast on his assumption that the ratio between connected houses and connections (customers) is now and will remain about 1.4 : 1 outside Karachi and about 1.15 : 1 in Karachi.

Comparable figures on the past performance of the utilities in the field of new connections are not available. However some comparison can be made with the figures given below, provided that the remarks in the footnotes are borne in mind.

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

	1960	1961	1962	1963	1964	1965
WAPDA a/	295	339	414	486	564	637
KESC b/	67	72	78	86	96	
Other utilities c/	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

a/ WAPDA figures, which refer to fiscal years, include commercial connections, which are probably about 10 percent of the total.
b/ KESC figures, while covering only residential customers, are only estimates because many residential customers in Karachi have more than one meter.
c/ No figures are available on connections maintained by the other electric utilities -- chiefly REPCO in Rawalpindi and MESCO in Multan -- but the total in existence is probably not large, at most 10 percent of those maintained by WAPDA.

These figures indicate that WAPDA has been making about 70,000 to 80,000 new connections (in the "general" tariff classification -- i.e. including commercial customers) a year on average over the past five years at an average annual rate of growth of 16.5 percent. About 50,000 of these were probably residential customers. KESC appears to have been making about 8,000 new residential connections a year. If the past five years have seen an average of 60,000 to 65,000 new residential connections over the whole of West Pakistan, as these figures suggest, then Stone & Webster's targets are ambitious, but they do not appear to be impossible to attain -- in the fiscal year 1965/66 WAPDA apparently made about 80,000 new residential connections. A rate of electrification higher than Stone & Webster's projection might be difficult to reach.

Having the 1960 Housing Census available as well as a number of socioeconomic surveys of the major cities of West Pakistan and of some rural areas in the North, the power consultant made the housing unit the basic building block of his residential load forecast. He chose 1965 as the base-year for his forecast. At the time when the forecast was made, actual data on residential sales in 1965 were not available. However, the power consultant projected residential load by regions from the data available on preceding years' sales; he projected the number of housing units in existence in 1965 on the basis of the 1960 Housing Census and the 1961 Population Census; and he estimated the percent electrical saturation of houses by areas on the basis of available socioeconomic surveys, his own field-checks, and cross-checks with any other information on which he could lay his hands. From the base-year of 1965, he proceeded in the same manner, projecting the number of houses in each area in the key years 1970, 1975, 1980 and 1985, on the basis of population projections for those years, and then estimating the proportion of houses which might be expected to be electrified by each key year. The gradual growth of electricity consumption per house

was also forecast on the basis of the estimated use in 1965. Multiplication of the electrified houses in each area by the projected average annual consumption per house gave a figure for total domestic consumption for each area in each key year.

In order to check the consistency of Stone & Webster's estimates with other portions of the overall development program prepared by the Bank Group and its consultants, the Bank Group subjected the power consultant's residential load forecast to detailed examination, using material gathered by Stone & Webster and information provided by WAPDA, KESC and the Planning Commission.

Since Stone & Webster and the irrigation consultant had used different population projections for their work and since the irrigation consultant's projection appeared to be based on rates of population growth which may turn out to be unduly low in the early part of the Perspective Plan period, the Bank Group used a slightly higher population projection as the basis for its testing of the residential load forecast -- about 67 million people in 1975 and 89 million in 1985. (See Appendix II below.)

Base-Year Residential Sales of Electricity

Any figures regarding residential power load must be treated with considerable skepticism. The main utilities in Pakistan do not keep records which indicate clearly sales to residential consumers, let alone residential consumers in urban areas as opposed to rural areas; nor is it even possible to determine with any great degree of precision the number of residential consumers in any area. Data on the smaller electric utilities is extremely sparse. However, in order to obtain as realistic a base as possible for projection purposes, the Bank assembled residential sales of electricity in calendar year 1964 on the basis of data gathered by Stone & Webster, WAPDA and KESC accounts,and information gathered by the Central Statistical Office on the smaller utilities. The results are summarized below:

Table 3

Estimated Residential & Commercial Sales of Electric Utilities 1964
(Million kwh)

		Domestic Urban	Domestic Rural	Commercial	Total
North	- WAPDA	135.0	35.0	40	210.0
	Other Utilities	21.0	1.0	12	34.0
Upper Sind	- WAPDA	1.5	1.0	2	4.5
	Other Utilities	4.0	0.5	-	4.5
Lower Sind	- WAPDA	13.0	1.7	6	20.7
Baluchistan	- WAPDA & Others	4.7	0.6	3	8.3
Karachi	- KESC	89.0	-	62	151.0
TOTAL		269	40	125	433

In order to make a rough estimate of the number of people receiving residential supplies of electricity, information provided by Stone & Webster was studied in conjunction with available socioeconomic data. The most detailed information was found in the 1955/56 National Family Expenditure (NFE) Survey of Karachi and other urban areas in Pakistan. However, this information is somewhat out-of-date and the survey was rather narrow in coverage, being largely confined to employees. Income-distribution data that have been collected more recently in wider surveys suggest that the NFE Survey failed to cover about the top 10 percent of family incomes. Therefore, in an effort to get at the relationship between income distribution and electrification, the data in the old NFE surveys of the Punjab, Peshawar and the Sind regarding proportions of the population in different income groups were adjusted to bring them roughly into line with the new broader studies, but the figures on the degree of electrification at a given income level were left unchanged. Karachi has been the object of several surveys, in particular a large-scale sample survey carried out by the Central Statistical Office and the Pakistan Institute of Development Economics in 1959-61, and information from this study was used in place of that from the NFE Survey. The results, which check out quite well with Stone & Webster's aggregate estimates of urban electrification, are presented below:

Table 4

Relationship Between Urban Income Distribution & Electrification 1960-64

(1)	Northern Grid (2)	(3)	(4)	Sind & Baluchistan (5)	(6)	(7)	Karachi (8)	(9)	(10)
Fam.inc. group (PRs/mo.)	% of Pop.in each group	% of (2) con-nected	% of Pop. con-nected (2x3)	% of Pop.in each group	% of (5) con-nected	% of Pop. con-nected	% of Pop.in each group	% of (8) con-nected	% of Pop.con-nected (8x9)
Less than 100	40.0	15.2	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
Over 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

The table indicates that the vast majority of families 1/, even in the relatively prosperous urban areas have 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. At given income levels,

1/ The definition of a "family" -- a group of persons with a common head -- is, of course, slightly different from the definition of a "household" -- a family or group of persons living together and eating from the same kitchen. In practice, the difference in average size between a family and a household in West Pakistan does not appear to be significant.

electrification tends to be highest in the older cities of the North, and lowest in the Sind; however, Karachi stands out for the relatively low levels of electrification attained for families in the lower income brackets. Also, despite the fact that there are more families in Karachi than in the North in the higher income groups, electrification is much less widespread because of the significantly lower levels of electrification applying to each income group. Urban electrification is highest in the North and lowest in the Sind. The predominance of relatively low-income consumers is noticeable in WAPDA's area, while in Karachi the majority of consumers have family incomes in excess of PRs 200 a month.

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. Some explanation of this fact is provided by the following table about Lahore, based on the detailed socioeconomic survey carried out there by the University of the Punjab. The high overall levels of residential electrification in Lahore are not representative for the North as a whole. The table indicates that in almost every section of Lahore the percentage of people receiving domestic supplies exceeded the percentage with family income exceeding PRs 100 per month. The foregoing table suggested that, in the North as a whole, 60 percent of the families had monthly incomes greater than PRs 100 per month, whereas only about 40 percent were electrified. What the Lahore table does show is that the most striking differences between percentage of people with family incomes greater than PRs 100 per month and percentage of people electrified can be accounted for by high density. In other words, poorer families are able to have electricity because they join up with other families and live several families to one house. This fact comes out most strikingly in areas 25-26 (Anarkali) and 27 (Gowal Mandi).

As an indication of the combined effects of income levels and density, Column (4) in the table was compiled by adding together Columns (2) and (3). In general, Column (4) shows a close correlation with Column (5). The main outstanding differences can be explained by the very high proportion of families with outstandingly high income levels in some areas (e.g. area 16 (Gulberg) and area 17 (Model Town), and by the exceptionally low proportion of such families in other areas (e.g. area 15 (Dharampura) and 30 (Shahdara)). In only two areas do the combined effects of income levels and density seem inadequate to explain the high degree of electrification recorded -- areas 18-20 (Wahdat Colony) and 23 (Mozang). Wahdat Colony is mainly a Government housing estate whose inhabitants receive quarters there as part of their remuneration. It was built by the Government and each house was electrified.

Table 5

Lahore: Residential Electrification

(1) Area	(2) Density: Population per Dwelling	(3) Wealth % of Households w.inc.above PRs100/mo.	(4) Wealth & Density Indicator (2 + 3)	(5) Actual % of Dwellings electrified
1 - 3	15.8	58.4	74.2	74.3
5	12.3	49.2	61.5	63.1
7 - 8	14.0	47.1	61.1	68.2
10 - 11	20.7	63.7	84.4	81.7
13 - 14	24.5	60.0	84.5	86.4
15	14.5	52.2	66.7	59.6
16	10.4	59.7	70.1	90.9
17	17.5	62.6	80.1	89.6
18 - 20	14.3	54.9	69.2	84.1
21 - 22	12.3	67.0	79.3	83.7
23	16.9	55.3	72.2	83.4
24	21.7	63.2	84.9	83.1
25 - 26	35.0	50.6	85.6	84.5
27	27.3	53.2	80.5	80.7
28	14.1	62.2	76.3	70.7
29	15.4	62.7	78.1	80.9
30	9.1	35.1	44.2	31.3
31	9.6	35.5	45.1	54.7
34	10.1	40.9	51.0	47.7
TOTAL	13.1	56.8		72.6

The very different situation in other towns is suggested by data available on Hyderabad, which show that the percentage of families electrified in various sections of the city is almost never as high as the percentage of families with monthly incomes above PRs 100 a month and is, in many cases, lower even than the percentage of families with incomes greater than PRs 200 a month. The data give the impression of a city expanding very rapidly with extremely uneven levels of electrification.

Table 6

Hyderabad: Residential Electrification

(1) Area	(2) Density: Population per Dwelling	(3) Wealth: % of households w. income above PRs200/month	(4) Wealth: % of households w. income above PRs100/month	(5) Actual % of Dwellings Electrified
1-A	7.5	23.5	53.7	23.0
2-G	5.0	8.6	37.4	4.1
3-G	6.1	9.1	37.3	11.0
4	9.0	21.2	53.8	33.0
5-G	5.0	12.0	38.5	16.0
6	5.2	12.2	42.9	6.0

Table 6 (continued)

(1) Area	(2) Density: Population per Dwelling	(3) Wealth: % of households w. income above PRs200/month	(4) Wealth: % of households w. income above PRs100/month	(5) Actual % of Dwellings Electrified
7	11.3	29.1	69.1	41.0
8	4.5	15.0	47.0	17.0
9	6.6	21.7	51.8	50.0
10	6.9	20.6	47.7	33.0
11	5.7	5.8	33.0	4.0
12	4.2	5.2	12.2	-
13	3.9	15.0	45.8	55.0
14	5.7	10.5	38.1	-
TOTAL	6.1	15.1	44.8	17.2

With an estimate of total residential sales in 1964 and the proportion of people in urban areas electrified, the base-year balance sheet on residential sales by areas can be drawn up (see Table 7). This balance sheet is based on families or households rather than houses, the unit used by Stone & Webster, because income distribution data are available on the former and not the latter.

The Growth of Residential Electrification

Comparative international studies undertaken in the Bank some years ago suggest that there may be a minimum family income level of about $500 per annum, at which electrification becomes possible, if none of the costs are subsidized. This is believed compatible with a figure of about $60 as the cost of electrification of a very simple house (including wiring, but excluding the cost of electricity-using appliances). At the current exchange rate $500 annual family income would correspond to a monthly income of about PRs 200. The estimates given in Table 4 imply that in Pakistan residential electrification extends substantially below this income level, and, moreover, that the bulk of WAPDA's customers are receiving family incomes of less than PRs 200 per month. This partly results from the very high density of low-income families, as suggested by Table 5, and partly no doubt from the fact that industrial enterprises in Pakistan and the Government often provide housing for their employees. The average income of families receiving domestic supplies of electricity is almost certainly higher. The 1955/56 National Family Expenditure Survey provides data from which the figures in Table 8 have been computed, indicating that electricity expenditure accounted for only a very small proportion of the total purchases of average electrified households.

Table 7

Estimated Residential Consumption of Electricity, 1964

		Population (1000's)	% of Pop. electrified	Av. size of elec. h'hold[a]	No. of h'holds electrified	Av. annual use per elec. h'hd. (kwh)[b]	Total Consumption (mln. kwh)
North	- Urban	5,650	40	6.5	346,690	448	156
	Rural	32,920	6	6.0	329,200	110	36
Upper Sind	- Urban	390	16	6.0	10,900	530	5.5
	- Rural	3,250	2	5.5	11,800	125	1.5
Lower Sind	- Urban	760	18	6.5	21,050	620	13
	- Rural	3,000	2	5.0	12,000	140	1.7
Baluchistan	- Urban	121	35	5.5	7,700	610	4.7
	- Rural	1,390	1	5.0	2,780	215	0.6
Karachi	- Urban	2,420	26	6.0	104,870	850	89
	TOTAL	49,901	10	-	847,490	363	308
Total Urban		9,341	33	-	491,710	545	268.2
Total Rural		40,560	5	-	355,780	112	39.8

a/ Average household size in West Pakistan is about 5.5 persons, and electrified households are shown by the sample surveys to be somewhat larger on average. For instance, the Karachi survey found the average size of all households to be 4.4 persons, whereas the average size of an electrified household was 5.2 persons.

b/ Average consumption per household appears to be lower in the North than elsewhere in the country; this may be related to the fact that a larger proportion of the population is electrified in the North. Average consumption per household may have been higher than indicated here in Karachi (as Stone & Webster suggests). A billing analysis undertaken in 1964 suggested that the average consumption per household may have been about 900 kwh p.a. However, the 1955/56 Family Expenditure Survey, while admittedly biased towards the lower-income groups, suggests that the average connected employee family was then paying for between 200 and 350 kwh a year. Prior to 1956 KESC kept records which distinguished between residential and commercial customers and the amounts of energy supplied to each group. These figures indicate that average consumption per customer over the period 1951 to 1955 was about 540 kwh per annum and that average consumption was growing at a rate of about 4 percent per annum. Projection of the figure of 540 kwh in 1953 at 4 percent per annum for 11 years suggests that average consumption per customer in 1964 would have been about 850 kwh. This happens to correspond very exactly to the estimated average annual consumption of about 250 "Middle-class" households interviewed by Zafar and Associates in 1963/64. An average annual consumption of 850 kwh per customer would suggest an average annual consumption per household of about 700-800 kwh since there is more than one consuming household on some meters.

Table 8

Monthly Average Family Incomes and Expenditure on Electricity

Location & Class		Av. Income of Electrified Families (PRs/month)	Expenditure on Electricity (PRs/month)	Electricity Purchases as % of Income
Hyderabad	- Industrial	111	0.8	0.7
Hyderabad	- Comm. & Govt.	138	3.1	2.2
Lahore	- Industrial	142	2.8	2.0
Lahore	- Government	201	4.2	2.1
Lahore	- Commercial	227	5.1	2.2
Lyallpur		110	0.06	0.05
Mardan		93	0.3	0.3
Multan		120	0.08	0.07
Peshawar	- Industrial	143	6.0	4.2
Peshawar	- Government	191	3.2	1.7
Peshawar	- Commercial	209	3.8	1.8
Quetta		125	0.5	0.4
Rawalpindi		216	0.8	0.4
Sialkot		135	3.6	2.7
Sukkur		130	0.9	0.7

Electricity consumption is such a small item in family expenditure that there was most likely some undercounting in this survey. As an overall average it would seem reasonable to suppose that expenditures on electricity may account for as much as 3 percent of the income of electrified families. In the U.S., expenditures on electricity vary from about 1 percent of income in the high income bracket to a maximum of 3 percent among low-income families. Table 7 indicated that residential electrification in West Pakistan was most widespread in the urban areas of the North and that annual family consumption of electricity was about 450 kwh on average. If this electricity supply was charged at current WAPDA rates it would cost about PRs 0.215 per kwh or a total of nearly PRs 100. On the assumption that electricity purchases are about 3 percent of annual income, this would imply that the average income of an electrified family in the North is about PRs 260 per month. This figure is consistent with other partial data available.

As a first indication of the potential for expansion of residential electrification it seems reasonable therefore to calculate the existing backlog of families who might be expected to pay for domestic electricity supply if it were available -- i.e. the number of families with monthly incomes in excess of PRs 200 per month who are not yet electrified. If we assume that families just reaching the threshold level for electrification of about PRs 200 monthly income can afford to spend about 2-3 percent of annual income on domestic electricity supplies, then this would imply that they could purchase, at current WAPDA rates, between 230 and 360 kwh a year. 230 kwh is about the minimum supply required for an urban dwelling -- enough, for instance, to support an iron or a radio for a year plus one 50-watt bulb burning six hours a day throughout the year.

Table 9

Distribution of Income in West Pakistan a/

Family Income Group (PRs/month)	Percent of Population in each Income Group			
	Urban North	Urban Sind	Karachi	Rural West Pakistan b/
Less than 100	40.0	54.1	29.2	36.1
100 - 200	39.0	32.7	38.6	47.0
200 - 400	11.0	9.0	22.0	14.1
Above 400	10.0	4.2	10.2	2.8

a/ Data from the Quarterly Surveys of Current Economic Conditions which were undertaken in 1963/64 probably provide better data than that used here, which is based mainly on older surveys by the Central Statistical Office and universities in Pakistan (see discussion on page 5 above). However, data from this survey was received too late and in too aggregated form to be used here. In general terms the results of the new survey seem to indicate significantly higher income levels -- less families in the lowest group and more in the top two groups, especially the PRs 200-400 monthly income group. The data from the new survey is summarized here in terms of percentages of the urban, rural and total population.

Monthly Family Income (PRs)	Urban	Rural	Total West Pakistan
Less than 100	15.7	28.5	25.7
100 - 200	41.7	43.3	42.8
200 - 400	29.6	23.4	25.1
More than 400	13.0	4.8	6.4

b/ Data from Central Statistical Office, National Sample Survey (Second Round) 1960. The First Round of the National Sample Survey (1959) suggests a generally similar distribution of rural incomes, but a larger proportion of people in the lowest income group (less than PRs 100) than in the second lowest (PRs 100-200).

Comparison between the number of people in the two highest income groups, as shown in Table 9 above, and the proportion of people in those income groups already receiving domestic supplies of electricity yields the following estimate of the "existing backlog" in terms of families:

Urban North	33,000
Urban Sind	18,000
Karachi	62,000
Rural areas a/	830,000

a/ Defined here, and elsewhere in this Annex, as settlements with less than 25,000 inhabitants each.

The figure for Karachi is important because it represents a relatively high proportion of the total population of the city (about 15 percent). The figure for rural areas is, of course, high (about 12 percent of total rural families) because of low incomes there and, more importantly, because of the absence of electricity supplies in most rural areas 1/. If this "backlog" were to be filled, then residential electrification would have to rise from about 40 percent of households to 44 percent in the Urban North, from about 18 percent to 27 percent in the Urban Sind, from 26 percent to 41 percent in Karachi, and from 5 to about 17 percent in rural areas.

While these figures give some indication of the potential for further electrification within the existing income pattern, they show nothing about the long-term potential for residential electrification. The Perspective Plan, however, projects an approximate doubling of family incomes between the base of 1960-65 and the target date of 1985; the implications in terms of new residential connections can be examined if the same threshold level of PRs 2,400 annual family income is maintained. The calculation is summarized in the following table.

Table 10

"Perspective Plan" Level of Residential Electrification, 1985

	Urban North	Urban Sind	Karachi	Rural W.Pakistan
1. Population (millions)	16.7	4.0	6.2	62.1
2. Percent with family income above PRs 200/month a/	60.0	45.0	70.0	60.0
3. Population w. family income above PRs 200/mo. (mln.) (line 1 x line 2)	10.0	1.8	4.3	37.3
4. Av. size of family	6.5	6.3	6.0	6.0
5. Electrified families (mlns.)	1.54	0.29	0.72	6.22
6. Stone & Webster's projection b/	1.49	0.26	0.57	2.69

a/ Calculated from Table 9, by transferring all those presently in the PRs 100-200 monthly family income group into the above PRs 200 group.

b/ For comparability with our figures, the Stone & Webster estimates have been converted from a "house" to a "family" base, using the above projections of population and average size of family and Stone & Webster's residential electrification percentages.

1/ The National Sample Survey (First Round) 1959 reported that only 5 percent of villages in West Pakistan were within one mile of a radio and nearly 40 percent were more than ten miles distant from a radio. WAPDA data indicate that, by the end of 1966, about 2,000 villages had been electrified. This represents 5 percent of the 40,000 estimated total number of villages in West Pakistan.

For purposes of comparison the Stone & Webster projections of electrified families, by areas, is included in the above table as line 6. It should be recalled that line 5 understates the degree of residential electrification implied in the Perspective Plan to the extent that it excludes totally residential electrification below the PRs 200 per month family income level; yet there is already a certain amount of electrification beneath this level. Most of the families below this income level who are presently connected will probably rise above the PRs 200 "threshold" within the Perspective Plan period. Moreover, the figures shown above would still leave some room for electrification below the PRs 200 income level to the extent that 100 percent electrification above that income level is not achieved.

The similarity between these "Perspective Plan" projections of residential electrification and the Stone & Webster projections is striking in urban areas. The greatest divergence occurs in the case of Karachi, where there is a higher proportion of the population concentrated in the higher income levels than elsewhere in Pakistan. The figures, based on estimated current income distribution, imply that by 1985 only 30 percent of the population would remain below the PRs 2,400 per annum family income level in Karachi, as compared with 40 percent in the rest of West Pakistan.

Rural Electrification

The figure of connected rural families which has been derived from the Perspective Plan is very much higher than the Stone & Webster projection of rural electrification. The consultant projects that 26 percent of the rural population might be connected by 1985, whereas our figures suggest that 60 percent of the rural population will be above the threshold income level and hence will be connected. The assumption of a direct correlation between income level and electrification which has been used for urban areas is, of course, much less realistic for rural areas, where the cost of electrification is higher than in town and where electric power is frequently simply not available close by. The extension of electrification to rural areas should be more closely related to the expansion of the tubewell program than to rural income levels, as it has been in recent years 1/.

Volume II of this report recommends a very substantial program of tubewell development over the coming twenty years. By 1985 about 80 percent of the canal-commanded area in the Province would have been brought under the tubewell program, either for purposes of irrigation or for drainage of saline groundwater. Rough estimates suggest that about 30 percent of the rural population (as here defined) would be in areas covered by the tubewell program by 1975, and about 60 percent of the rural population would

1/ Most of the rural electrification which has taken place in recent years appears to have been in the SCARP I area.

be in such areas by 1985. If the tubewell program is implemented, therefore, 60 percent of the rural population should by 1985 be living in areas where distribution lines have been constructed. Application of the threshold income concept to this proportion of the rural population would imply that about 3.7 million rural families (60 percent of 6.22) should be connected by 1985. This is about 1 million more than Stone & Webster's projection of the number of rural families connected by 1985.

Even the lower Stone & Webster target of new rural connections -- about 2.3 million over the 20-year period -- implies a very sizable investment in rural electrification. The Third Plan allocates PRs 255 for electrifying 4,000 villages or an average of PRs 64,000 ($13,400) per village. This figure appears to be on the low side, but if it is accepted for present purposes, and if it is further assumed, following WAPDA documents, that an average of about 40 families would be connected in each village, then the cost of electrification works out at an average of about $335 per family. The consultant's target of rural electrification would imply an investment over the Perspective Plan period of about PRs 3.7 billion or $800 million. It should be recalled that rural population has been defined here to include all those living in places of less than 25,000 inhabitants, so that many of the new connections may in fact be in small towns where, due to economies of scale in expanding the distribution system, the average cost might be less than $335 per family. Nevertheless it is clear that the cost will be high. The rural electrification target derived from the simple calculation on the basis of income distribution would imply an investment in rural residential electrification more than two-and-a-half times as great and even the target based on the tubewell program would imply an investment about 40 percent greater. The investment for the Stone & Webster program already seems an ambitious target and, as shown on page 3, the increase in annual number of new connections required to implement the Stone & Webster program would place a heavy administrative burden on WAPDA.

The extent to which the Stone & Webster target of rural electrification would already represent a deviation from past experience is suggested by Table 11 below. West Pakistan presently has a per capita income of about $95 at the current exchange rate, and the Perspective Plan would therefore imply a per capita income of a little less than $200 by 1985. The highest level of rural electrification presently attained by countries in this range of incomes appears to be about 10%.

The income distribution and residential electrification patterns inferred above from the Perspective Plan might be criticized on the ground that they give insufficient place to the income-equalization target of the Plan. According to the projections used by the Bank, nearly 40 percent of the population would remain in 1985 with family incomes below PRs 200 per month. These projections do of course still allow much room for equalization of incomes in the middle and upper ranges -- with, say, a reduction in the heavy concentration of income among a small number of high income receivers and its redistribution among the

middle groups. Moreover, these projections do imply much wider distribution of the benefits of economic growth than attained in other countries, insofar as rural electrification is carried much further than in countries already at Pakistan's projected 1985 income level. This is reasonable in view of the relatively low marginal cost of rural residential electrification which accompanies the tubewell program, which, as Stone & Webster point out, provides West Pakistan an unusual opportunity for spreading the benefits of electrification.

Table 11

Comparative Levels of Residential Electrification a/

Country	Year	Per Capita Income (US$)	% of dwellings electrified Total	Urban	Rural
Australia	1961	1,254	96.2	99.2	81.3
Puerto Rico	1960	658	79.9	94.3	66.7
Cyprus	1960	446	43.1	90.4	21.5
Greece	1961	370	53.1	81.4	13.6
Malta	1957	334	72.9	84.1	60.5
Costa Rica	1963	329	54.6	93.5	31.6
Cuba	1953	313	55.6	82.9	8.7
Nicaragua	1963	296	40.8	76.0	4.5
Portugal	1960	237	40.5	88.5	27.4
Colombia	1951	214	25.5	63.5	4.2
Jordan	1961	205	17.0	39.2	1.4
Honduras	1961	182	14.6	56.7	1.9
Peru	1961	171	30.1	52.9	4.8
Syria	1962	159	38.0	87.7	10.5
UAR	1960	156	37.8	-	-
Iraq	1956	150	17.1	-	-
Ecuador	1962	148	33.1	79.5	9.2
Dominican Republic	1955	146	15.5	51.1	2.4

a/ Source: derived from data given in U.N. Statistical Yearbook 1964. Incomes were converted into U.S. Dollars at official exchange rates or, in cases where free rates were given, at averages between official rates and free rates for the relevant years.

The objective of the Perspective Plan was interpreted for purposes of this analysis as being to double every family's income level. Given the income categories used here, this would be consistent with the target of income equalization stated by the President of Pakistan in the Preface to the Third Five Year Plan 1/: "The Government is also determined that a certain minimum income should be assured to every citizen. At present, ... about 24 percent /of the total households/ in West Pakistan obtain a monthly income of less than PRs 100. Such a maldistribution of income is totally unacceptable. We are determined to ensure that no household should have a monthly income of less than PRs 100 by 1985."

1/ Third Plan (June 1965) page v.

Future Levels of Electricity Consumption

The other main dimension of growth in residential power load, after increase in the number of connections, is growth of the average load per residential consumer. Figures on past growth of average consumption per household in West Pakistan are not available, because the utilities do not keep separate statistics on residential consumers. Such information as is available suggests that total residential load may have been growing in Karachi in the last few years at about 14 percent per annum, made up from 9 percent per annum growth in connections and 5 percent per annum growth in average consumption per household. WAPDA's residential load may have been growing at about 19 percent per annum, made up from 15 percent per annum growth in connections and 4 percent per annum growth in average consumption per household. Thus growth in the average consumption per household has been less important than increase in the number of consumers in both markets, but it has been more important as a component of overall residential load growth in Karachi than in the WAPDA area. This is in line with the tables presented above, which indicate that residential electrification is more highly concentrated in the upper income groups in Karachi than it is in the WAPDA area. It is also consistent with the results that might be expected from the different residential rate policies of KESC and WAPDA: a new customer in Karachi must make a substantial initial capital contribution, averaging PRs 250 per domestic customer, to cover all connection costs over 100 feet from the nearest line, whereas a new WAPDA customer has no initial capital contribution to make but has to pay a higher rate for his electricity, which Stone & Webster estimates at about 21.5 paisa (US cents 4.5) per kwh.

Current average annual consumption per electrified household was estimated above (Table 7) at about 450 kwh in the Urban North, where electrification is most widespread, 850 kwh in Karachi with its relatively high-income consumers, and about 600 kwh in the Sind where urban electrification is least widespread. The bulk of rural consumers are in the North and average consumption there is estimated at about 110 kwh per annum; average rural consumption again appears to be somewhat higher in the South where it is less widespread and the consumers, such as they are, are longer established. Comparative international research undertaken some years ago in the Bank suggested that electricity consumption by established residential consumers could grow in low-income countries at about 7 percent per annum. This would imply, for instance, that average consumption of existing consumers in the Northern towns would rise to about 630 kwh in 1970, 890 kwh in 1975, 1,240 kwh in 1980, and 1,740 kwh in 1985. An indication of how this demand might be built up is given by the following list of electrical appliances which a recent survey showed to be in use at present in some homes in Karachi. Opposite each appliance is placed an estimate of its initial cost and its annual energy requirement.

Table 12

Cost and Power Consumption of Selected Electrical Appliances

Appliance	Approx. Retail Price (PRs)	Watts	Av. Annual hrs. of use	Av. Annual Electricity Consumption (kwh)
Domestic				
Fan (ceiling)	200	60	2,000	120
Fan (table)	150	55	2,000	110
Electric heater (2 bars)	60	2,000	250	500
Electric heater (1 bar)	40	1,000	250	250
Electric iron	55	750	100	75
Electric kettle	95	1,500	300	450
Water heater (6-gallon)	550	1,000	200	200
Water heater (12-gallon)	725	1,500	200	300
Sewing machine	1,600	80	100	8
Hot plate	150	1,000	350	350
Imported				
Electric heater (2 bars)-UK	165	2,000	250	500
Electric heater (1 bar) -UK	135	1,000	250	250
Airconditioner (2-ton) -US	4,700	2,080	2,000	4,160
Electric iron -UK	95	750	100	75
Electric kettle -Germany	125	650	300	195
Vacuum cleaner - Japan	925	350	100	35
Refrigerator (5 cu.ft.) -Germany	1,600	95	7,000	665
Refrigerator (10 cu.ft.)	2,750	130	7,000	910
Washing machine	3,800	480	100	48

Many of these goods -- including refrigerators, space-heaters, fans, radios and airconditioners -- are already produced in West Pakistan. Plans exist to produce most of the rest of them and some other appliances, such as vacuum cleaners and blenders, domestically by the end of the Third Plan. Nevertheless, in the past, a large number, apart from fans and radios, have been imported. Tariffs on such goods are high and, because these goods are scarce, the importers' mark-ups are also high. Prices of the same goods produced by the heavily protected domestic industry are also likely to be high. A reasonable assumption would seem to be that a family might have to pay some PRs 1,300 1/ to obtain enough appliances to raise average electricity consumption from the estimated current 450 kwh per annum to about 1,740 kwh per annum. For example, this might include the following:

1/ Covering the cost of initial purchase only. Replacement costs are not taken into account here.

	Kwh	PRs
Electric heater	250	40
Water heater	300	725
Electric kettle	450	95
2 ceiling fans	240	400
Iron	75	55
	1,315	1,315

The average income of a connected household in the Northern towns was estimated above (page 10) at about PRs 3,000 per annum (PRs 250 per month). Can a family with an income that is now about PRs 3,000 and that should rise by 1985 to about PRs 6,000 be expected to purchase over 20 years a minimum of PRs 1,300 worth of electrical equipment? An average annual expenditure of PRs 65 on electrical appliances may not appear unrealistic by comparison with the family budget data collected by the 1955/56 NFE Survey, but the survey did suggest that even families with higher incomes among those surveyed of over PRs 200 per month still had to spend all but a tiny proportion of their incomes on food, clothing and housing. 1/ However, this survey was somewhat biased toward lower income groups. Total average expenditure of PRs 1,300 on electrical appliances over 20 years would represent a little less than 5 percent of the additional income that should accrue to the average electricity-consuming family over the 20-year period. Thus an average rate of growth of 7 percent in electricity consumption by existing residential consumers seems reasonable when account is also taken of the likely gradual decline in the cost of electrical appliances as economies of scale are achieved and of the likely high marginal elasticity of demand for consumer durables.

A factor of more significance in the overall residential load forecast, because of the important role that new connections will continue to play, is the average consumption level at which new consumers will come on line -- and the rate at which their consumption will grow. Studies at the Bank have suggested that average electricity consumption per residential consumer depends partly on income level and partly on the length of time that a family has had electricity (and has therefore been able to accumulate appliances). Most of the new consumers in West Pakistan will be in low income groups (except perhaps for a few years in Karachi where there is a relatively sizeable number of families above the threshold level but still unelectrified). This will tend to keep their initial level of

1/ Data from the Quarterly Surveys undertaken by the Central Statistical Office in 1963/64 confirm this fact. Average expenditure on 'furniture and utensils' is shown at less than 1 percent of total consumption expenditure. One percent of the total expenditure over the next 20 years of the 'average' electricity-consuming family defined above would clearly be less than PRs 1,300. However, this does not give a clear guide for many reasons, among them the fact that electrical appliances are frequently built into a house and thus occur in expenditure surveys as part of rent.

consumption low and to prolong the time that they require to accumulate appliances. Current initial consumption level in the WAPDA area is probably around the minimum required simply to provide lighting and a fan or a radio -- about 250 kwh per annum. The shift of Government and related activities from Karachi to Lahore-Rawalpindi-Islamabad could have a noticeable effect on this initial level of consumption in the next few years. Moreover, over time, as income levels rise and appliances become more available at lower prices, initial consumption levels are likely to rise. In Karachi initial consumption levels are presently probably above those experienced by WAPDA. With the significant backlog of unconnected families that are sufficiently wealthy to be electricity consumers, this will probably continue to be the case for the next few years. The effect of the shift of Government to the North will probably be noticeable chiefly in cutting down the rate of growth of consumption by existing consumers in Karachi. In later years, when KESC's initial capital contribution requirement has been removed and KESC rates brought more into line with WAPDA's, there will likely be a rapid expansion of the number of consumers, and, since they will tend to be more in the lower income groups, their initial consumption level will be lower than suggested by past experience in Karachi.

The rate of growth of electricity usage by new consumers will probably be quite high in the early years after initial connection, especially where a backlog of families who could afford electricity relatively easily is being made up; it could well double within little more than five years. This would represent the extension of lighting, addition of a fan or two, a radio and an iron -- all quite inexpensive items and cheap relative to their consumption of electricity. Over a slightly longer period the growth of consumption would probably slow down considerably, but it could remain above that experienced by older consumers for another few years.

Conclusions

To summarize the discussion in the preceding pages, the amount of electricity consumed in the household sector depends on the number of consumers, the rate at which their number is increasing, and the levels of consumption of both old and new consumers and the rate at which these increase. These various factors can be built into a formula (see Appendix I) and thus brought to bear in the forecast of residential power loads. The formula has been applied to each of the four main groupings of population used in this annex -- Karachi, Northern Urban, Sind and Baluchistan Urban, and West Pakistan Rural. The details are presented in Appendix I.

The results of this procedure are summarized in Table 13 below. The proportion of population here assumed to be electrified is not substantially different in any year from the proportion projected by Stone & Webster. It is somewhat higher in Karachi, as indicated in Table 10. For the rural areas we have adopted the percentage electrification levels projected by Stone & Webster, rather than the levels coming out of the income-distribution approach, for reasons given in

the discussion of Rural Electrification above. The total number of families connected by 1985 according to our analysis is about 5.1 million, slightly higher than Stone & Webster's 4.9 million. Nevertheless, total sales to the residential sector come out consistently lower on this projection than on that of Stone & Webster.

Table 13

Bank Group's Calculated Residential Load Projection a/
(million kwh)

	1964	1970	1975	1980	1985	Implied Annual Rate of Growth 1964-85 (%)
Urban						
North	156	320	570	933	1,476	11.3
Sind & Baluchistan	23	43	61	110	200	10.8
Karachi	89	187	338	570	872	11.5
Subtotal	268	550	969	1,613	2,548	11.3
Rural						
W.Pakistan	40	78	159	304	546	13.3
TOTAL	308 (12.6)	628 (12.4)	1,128 (11.2)	1,917 (10.0)	3,094	11.6
Stone & Webster projection		727	1,325	2,270	3,700	

More than half of the overall difference between the two forecasts of residential load results from the fact that the calculated projection is based on an actual (1964) figure whereas Stone & Webster used a projected (1965) basis; this is indicated by the fact that the overall growth rates in residential load implied in the two forecasts are very similar. If the Bank Group's calculated growth rate is applied to Stone & Webster's base, then it would reach a residential load only about 250 million kwh or 7 percent lower than the Stone & Webster load forecast for 1985. The remaining difference between the two load forecasts results from the less rapid growth in average consumption per household that results from the assumptions used in the calculation made here. The figures used in the formula allow for the fact that most of the newly connected households, except possibly in Karachi, will be ones which can barely afford electricity. Because of the relatively expensive nature of electrical appliances, such households will come on line with a rather low level of consumption. The number of kilowatt-hours consumed may then grow quite rapidly -- at around 10 percent average -- as appliances are gradually accumulated, but, in the context of continuing large additions of low income families to the total power system, this is inadequate to raise the overall average consumption per household very rapidly.

a/ Figures in brackets represent average annual growth rates in percentage over the five-year periods in which they are inserted.

Appendix Table I

Stone & Webster Residential Load Forecast

	Population *(1000's)	% of pop. connected	Persons per house	No. of connected houses	Av. annual use per house (kwh)	Total Energy (mln kwh)	Rate of growth over preceding 5 years
1965							
North - Urban	5,950	41	6.0	406,000	510	207.0	--
- Rural	34,000	5	5.2	328,000	110	36.0	--
Upper Sind - Urban	411	19	5.6	14,000	340	4.8	--
- Rural	3,352	2	5.8	12,000	110	1.3	--
Lower Sind - Urban	679	25	7.0	24,000	613	14.7	--
- Rural	2,715	2	5.0	11,000	120	1.3	--
Baluchistan - Urban	370	15	4.2	13,000	430	5.6	--
- Rural	1,173	0.4	4.7	1,000	150	0.2	--
Karachi - Urban	2,550	26	6.6	102,000	1,090	111.0	--
TOTAL	51,200	9.5	5.3	911,000	418	382.0	--
Total - Urban	9,960	34	5.9	599,000	613	343.0	--
Total - Rural	41,240	5	5.2	352,000	110	39.0	--
1970							
North - Urban	7,780	46	6.3	570,000	638	364.0	11.9
- Rural	37,750	10	5.4	700,000	140	98.0	22.3
Upper Sind - Urban	540	25	5.7	23,000	450	10.4	16.7
- Rural	3,726	5	5.8	32,000	145	4.6	28.7
Lower Sind - Urban	890	31	7.2	38,000	764	31.0	16.0
- Rural	3,014	4.6	5.1	28,000	150	4.0	25.2
Baluchistan - Urban	480	19	4.3	21,000	480	10.1	12.5
- Rural	1,260	0.7	4.7	2,000	190	0.5	20.5
Karachi - Urban	3,260	33	7.0	155,000	1,320	204.0	12.9
TOTAL	58,700	14.9	5.6	1,569,000	463	727.0	13.7
Total - Urban	12,950	39.0	6.4	807,000	768	620.0	12.6
Total - Rural	45,750	9.0	5.4	762,000	140	107.0	22.4
1975							
North - Urban	10,220	50	6.4	800,000	770	616.0	11.1
- Rural	41,670	16	5.5	1,210,000	180	217.0	17.2
Upper Sind - Urban	712	31	5.8	38,000	550	21.0	15.1
- Rural	4,113	10	5.9	70,000	185	13.0	23.1
Lower Sind - Urban	1,174	38	7.2	63,000	920	58.0	13.3
- Rural	3,327	8	5.3	50,000	190	9.0	17.6
Baluchistan - Urban	614	22	4.4	31,000	612	19.0	13.5
- Rural	1,390	3	4.8	9,000	222	2.0	32.0
Karachi - Urban	4,080	39	7.1	230,000	1,610	370.0	12.6
TOTAL	67,300	21.2	5.7	2,501,000	530	1,325.0	12.7
Total - Urban	16,800	44.5	6.4	1,162,000	933	1,084.0	11.8
Total - Rural	50,500	14.5	5.5	1,339,000	180	241.0	17.6
1980							
North - Urban	13,440	54	6.6	1,100,000	920	1,012	10.4
- Rural	45,645	22	5.7	1,760,000	210	370	11.3
Upper Sind - Urban	930	39	5.9	62,000	655	41	14.3
- Rural	4,510	17	5.9	129,000	225	29	17.4
Lower Sind - Urban	1,540	44	7.2	95,000	1,100	105	12.6
- Rural	3,640	15	5.4	100,000	220	22	19.6
Baluchistan - Urban	790	24	4.5	43,000	720	31	10.3
- Rural	1,505	7	4.8	22,000	225	5	20.1
Karachi - Urban	5,000	47	7.2	330,000	1,980	655	12.1
TOTAL	77,000	28.0	5.9	3,641,000	623	2,270	11.4
Total - Urban	21,700	49.8	6.6	1,630,000	1,131	1,844	11.1
Total - Rural	55,300	20.6	5.7	2,011,000	212	426	12.1
1985							
North - Urban	17,680	58.0	6.7	1,500,000	1,070	1,600	9.6
- Rural	49,690	27.0	5.8	2,314,000	250	580	9.4
Upper Sind - Urban	1,230	45.0	6.0	92,000	750	69	11.0
- Rural	4,910	25.0	6.0	205,000	260	53	12.8
Lower Sind - Urban	1,990	49.0	7.2	135,000	1,280	173	10.5
- Rural	3,960	23.0	5.5	165,000	260	43	14.3
Baluchistan - Urban	1,020	29.0	4.6	64,000	800	51	10.4
- Rural	1,640	10.0	5.1	33,000	330	11	17.1
Karachi - Urban	6,080	55.0	7.3	460,000	2,240	1,120	11.3
TOTAL	88,200	34.0	6.0	4,968,000	744	3,700	10.2
Total - Urban	28,000	54.0	6.7	2,251,000	1,338	3,013	10.3
Total - Rural	60,200	26.0	5.8	2,717,000	253	687	10.0

APPENDIX I

AN ILLUSTRATIVE FORECASTING TECHNIQUE

If it is assumed that the various types of growth affecting the residential load can be approximated by compound rates of growth that are held constant over five-year periods, then it is possible to summarize all the elements discussed in this annex in a formula showing their aggregate effect on future residential consumption. The factors to be taken into account in the calculation are indicated as follows:

H_o	-	initial number of households connected.
C_o	-	initial average consumption per household.
c	-	rate of growth of consumption by original consumers.
r	-	rate of growth of households connected.
C'_o	-	initial consumption of newly connected households.
c'	-	rate of growth of consumption by newly connected households within the five-year period in which they are connected and over the following five-year period.

Consumption at the end of a five-year period may be divided into consumption by old consumers and consumption by newly connected households. Consumption by old consumers will be

$$H_o C_o (1 + c)^5$$

while consumption by new consumers, taking each year's group together will be

$$rH_o C'_o (1 + c')^4 + rH_o (1 + r) C'_o (1 + c')^3 + rH_o (1 + r)^2 C'_o (1 + c')^2$$
$$+ rH_o (1 + r)^3 C'_o (1 + c') 1 + rH_o (1 + r)^4 C'_o$$

The sum of these two expressions, the total residential consumption in the fifth year,

$$H_5\, C_5 = H_o \left[C_o\, (1 + c)^5 + rC'_o \left[(1 + c')^4 + (1 + r)\, (1 + c')^3 + (1 + r)^2 (1 + c')^2 + (1 + r)^3\, (1 + c') + (1 + r)^4 \right] \right]$$

but, $H_5 = H_o\, (1 + r)^5$ by definition, so that

$$C_5 = \frac{C_o(1+c)^5 + rC'_o \left[(1+c')^4 + (1+r)(1+c')^3 + (1+r)^2 + (1+r)^3(1+c') + (1+r)^4 \right]}{(1 + r)^5}$$

$$= C_o \frac{(1 + c)^5}{(1 + r)} + \frac{r}{(1 + r)^5}\, C'_o \left[(1 + r)^4 + (1 + r)^3\, (1 + c') + (1 + r^2)\, (1 + c')^2 + (1 + r)\, (1 + c')^3 + (1 + c')^4 \right]$$

$$= C_o \frac{(1 + c)^5}{(1 + r)} + \frac{r}{(1 + r)}\, C'_o \left[1 + \frac{(1 + c')}{(1 + r)} + \frac{(1 + c')^2}{(1 + r)^2} + \frac{(1 + c')^3}{(1 + r)^3} + \frac{(1 + c')^4}{(1 + r)^4} \right]$$

This equation can be further simplified by replacing the series in the second term with a formula for the sum of the terms:

$$C_5 = C_o \frac{(1 + c)^5}{(1 + r)} + \frac{r}{(1 + r)}\, C'_o \frac{1 - \frac{(1 + c')^5}{(1 + r)}}{1 - \frac{(1 + c')}{(1 + r)}}$$

This calculation has been made for each major market for each of the periods, 1964-70, 1971-75, 1976-80 and 1981-85, and is summarized in the following tables. In the use of the above equation, the number of consumers in each of the key years has been projected on the basis of the assumption regarding a threshold income level described in the annex. The growth rates of consumption have also been selected on the basis of the considerations discussed there, with special attention to the income level of consumers and their initial levels of electricity consumption. Starting levels of consumption for new consumers have been estimated on the basis of existing average consumption levels, a detailed breakdown of KESC's sales (under tariff R1) to residential consumers by amount of monthly consumption, and comparative international research in the Bank. An attempt has been made to take account of the shift of Government to the North in the assumptions fed into the analysis for the Northern cities. Equally allowance has been made in the Karachi analysis for the sizeable "backlog" of relatively high income families who are not yet electricity consumers; and the sizeable jump in the level of electrification in Karachi between 1970 and 1975 is postulated on the assumption that KESC's initial capital contribution requirement will be either reduced or eliminated.

Table 1

Northern Cities

	1964	1970	1975	1980	1985
Application of Formula					
Population electrified (%)	40	45	49	54	60
Old Consumers					
Number (in 1000's)	347	533	754	1,106	1,500
Average Consumption (kwh)	450	600	754	844	984
Growth of Consumption (% p.a.)	8	7.5	6.5	6.5	
New Consumers					
Growth of Connections (% p.a.)	7.2	7.5	8.0	6.3	
Initial Av. Consumption (kwh)	300	350	400	450	
Initial Growth of Consumption (% p.a.)	11	10	9	9	
Total Residential Sales (mln. kwh)	156	320	570	933	1,476

Stone & Webster Forecast	1965	1970	1975	1980	1985
Houses Electrified (%)	41	46	50	54	58
No. of Houses Electrified (1000's)	406	570	800	1,100	1,500
Use per House (kwh)	510	638	770	920	1,070
Total Residential Sales (mln. kwh)	207	364	616	1,012	1,600

Table 2

Sind and Baluchistan: Urban Areas

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	20	24	32	38	45
Old Consumers					
Number (in 1000's)	40	67	117	181	280
Average Consumption	585	638	525	605	712
Growth of Consumption (% p.a.)	6	7	7	7.5	
New Consumers					
Growth of Connections (% p.a.)	9	11.9	9.1	9.1	
Initial Average Consumption (kwh)	275	300	300	350	
Initial Growth of Consumption (% p.a.)	11	11	11	11	
Total Residential Sales (mln. kwh)	23	43	61	110	200

Stone & Webster Forecast	1965	1970	1975	1980	1985
Houses Electrified (%)	20	25	31	36	41
No. of Houses Electrified (1000's)	51	82	132	200	291
Use per House (kwh)	490	622	742	935	1,007
Total Residential Sales (mln. kwh)	25	51	98	187	293

Table 3

Karachi

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	26	34	48	59	65
Old Consumers					
Number (in 1000's)	105	181	319	502	673
Average Consumption (kwh)	850	1,032	1,062	1,136	1,296
Growth of Consumption (% p.a.)	8	8	7	7	
New Consumers					
Growth of Connections (% p.a.)	9.5	12.0	9.5	6.0	
Initial Average Consumption (kwh)	500	400	450	500	
Initial Growth of Consumption (% p.a.)	9	10	10	9	
Total Residential Sales (mln. kwh)	89	187	338	570	872

Stone & Webster Forecast	1965	1970	1975	1980	1985
Houses Electrified (%)	26	33	39	47	55
No. of Houses Electrified (1000's)	102	155	230	330	460
Use per House (kwh)	1,090	1,320	1,610	1,980	2,240
Total Residential Sales (mln. kwh)	111	204	370	655	1,120

Table 4

Rural West Pakistan

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	5	10	15	20	26
Old Consumers					
Number (in 1000's)	356	761	1,268	1,900	2,690
Average Consumption (kwh)	112	102	125	160	203
Growth of Consumption (% p.a.)	7	7	8	8	
New Consumers					
Growth of Connections (% p.a.)	13.5	10.7	8.5	7.2	
Initial Average Consumption (kwh)	70	80	90	100	
Initial Growth of Consumption (% p.a.)	12	12	12	12	
Total Residential Sales (mln. kwh)	40	78	159	304	546
Stone & Webster Forecast	(1965)				
Houses Electrified (%)	5	9	14.5	20.6	26
No. of Houses Electrified (1000's)	352	762	1,339	2,011	2,717
Use per House (kwh)	110	140	180	212	253
Total Residential Sales (mln. kwh)	39	107	241	427	687

APPENDIX II

POPULATION PROJECTION

The irrigation consultant and the power consultant used different forecasts of the future population of West Pakistan in arriving at their recommendations. Both started from a base-year population of 51.2 million in 1965, but the power consultant projected a linear annual increase of population at 2.8 percent per annum, whereas the irrigation consultant used a number of different growth patterns. These rates are summarized below:

Table 1

Annual Average Population Growth Rates used by Irrigation Consultant
(In percentage)

	1965/70	1970/75	1975/80	1980/85	Implied 1985 Population (mill.)	1985/2000
IACA Low	2.4	2.75	2.5	2.4	84	2.0
IACA High	2.4	2.75	3.1	3.0	89	2.75
Plancom High	2.4	2.75	2.75	2.75	88	2.4
Power	2.8	2.8	2.8	2.8	88	-

The differences among the consultants in their projections of the distribution of the population between urban and rural areas and between the different areas of the country are more extreme.

Other projections of the population of West Pakistan have been made, notably by the Pakistan Planning Commission and by the U.S. Bureau of the Census. 1/ The third row in the table above apparently represents one of the Planning Commission's several projections. It is a hypothetical growth pattern based on the assumption that the family planning program will not have a visible effect on the overall population growth-rate before 1985. It does imply, of course that family planning will have a sufficiently large effect on the birthrate for declines here to offset the effect of public health measures in reducing the death-rate. Since this growth pattern was formulated, doubts have grown as to whether the current population growth rate assumed (2.4 percent) is correct. PGE (Population Growth Estimation) studies have suggested that the current growth rate may be as high as 3.0 (birthrate of approximately 50/1000 and death-rate of 20/1000). The U.S. Census Bureau study uses a projection model and forms different sets of assumptions as to future trends in fertility and mortality rates. The study concludes that the 1985 population of West Pakistan might be, at lowest, 88.7 million. If fertility does not decline or if fertility decline is largely offset by further mortality decline then 1985 population would be substantially higher, quite possibly over 100 million.

1/ James W. Brackett and Donald J. Akers, "Projections of the Population of Pakistan, by Age and Sex: 1965-1986", U.S. Dept. of Commerce, June 1965.

The U.S. Census Bureau study may be unduly pessimistic, because it is based on the early PGE results which are still not fully confirmed and because it makes the rather artificial assumption that the family planning program will cease to expand after the initial target date of 1972, by which time one quarter of the women of childbearing age are expected to be using some contraceptive technique. On the one hand this target is probably considerably too optimistic for 1972, but on the other hand the program could, with an adequate effort, expand rapidly between now and 1972 and continue to expand thereafter.

The population projection attached is based on the 1961 census adjusted for an estimated 7.0 percent undercounting. It is based on the assumption that the current rate of population growth is about 2.6 percent and that the family planning program, while it gets the high priority which it deserves, will not be sufficient to have a noticeable effect on the overall population growth rate until 1980. The growth rate assumed for the period 1980-85 is 2.7 percent, as the effects of population control measures begin to outweigh a continuing decline in the mortality rate.

The regional distribution of the population is estimated on the basis of trend rates of growth and the likelihood that the Sind will gradually get an increasing share of the total population. Relatively substantial industrial growth is likely in the Sind (especially in Lower Sind) as development begins to spread out from Karachi; and there are a number of areas newly irrigated by Gudu and Ghulam Mohammed Barrages which have yet to be fully settled. Urban population (here defined as the population living in cities over 25,000) is projected to grow at slightly more than five percent over the 20-year period. 1/ The growth rate of Karachi is assumed to slacken somewhat, in line with past trends, to about 4.5 percent per annum, while the growth of urban population in the Sind will remain above the national average for the perspective plan period.

1/ This is supposed to be in line with the Planning Commission projections. These include a growth rate of the total urban population of about 5.3 percent, but are based on the census definition of "urban" which is much broader than the definition used here. Between 1951 and 1961 urban population on the census definition appears to have grown more rapidly (average annual rate of about 5.6 percent) than urban population defined as those living in cities which by 1961 were larger than 25,000 (average annual rate of about 5.4 percent). Therefore we use an urban population growth rate somewhat below the Planning Commission's.

Table 2

Projection of Population Distribution a/
(In millions)

	1964	1965	1970	1975	1980	1985
North						
Urban b/	5.65	5.95	7.70	10.0	12.9	16.7
Rural	32.92	33.55	36.90	40.8	45.7	50.0
Total	38.57	39.50	44.6	50.8	58.6	66.7
Upper Sind						
Urban	0.39	0.41	0.5	0.7	0.9	1.2
Rural	3.25	3.34	3.7	4.1	4.8	5.1
Total	3.64	3.75	4.2	4.8	5.7	6.3
Lower Sind						
Urban	0.76	0.80	1.1	1.4	1.9	2.5
Rural	3.00	3.06	3.4	3.8	4.2	4.6
Total	3.76	3.86	4.5	5.2	6.1	7.1
Baluchistan						
Urban	0.12	0.12	0.15	0.2	0.2	0.3
Rural	1.39	1.42	1.65	2.0	2.3	2.4
Total	1.51	1.54	1.8	2.2	2.5	2.7
Karachi						
Urban	2.42	2.55	3.2	4.0	5.1	6.2
Total	49.90	51.20	58.3	67.0	78.0	89.0
Total Urban	9.34	9.83	12.65	16.3	21.0	26.9
Total Rural	40.56	41.37	45.65	50.7	57.0	62.1
Rural (Census) c/		38.00	41.0	44.0	47.0	50.5

a/ As of January 1st of each year.

b/ "Urban" is defined for the purposes of this table as including all cities with populations in excess of 25,000. Allowance is made in the urban growth rates for the accession of new cities into the "above 25,000" category as a result of crossing this threshold level. Therefore the 1985 figures purport to indicate the total population in each region which will then be living in cities of over 25,000 population size.

c/ For purposes of comparison "rural" population is here defined as in the 1961 Census -- i.e. excluding all settlements with a population exceeding 5,000 as well as other places which the Provincial Director of the Census determined to have "pronounced urban characteristics" such as "common utilities, roads, sanitation, schools and specially non-agricultural occupation of the people."

ANNEX 4

THE OVERALL ENERGY SITUATION -- SUPPLY AND DEMAND

THE OVERALL ENERGY SITUATION -- SUPPLY AND DEMAND

Table of Contents

THE OVERALL ENERGY SITUATION -- SUPPLY AND DEMAND

Outline

The first section of this annex analyzes West Pakistan's energy resources and briefly assesses their adequacy. The second section shows recent trends and projections of supply of and demand for energy; it appraises the cost of potential new generating equipment. This annex ends up by a synthetic perspective on the overall energy balance.

Introduction

The chief known energy resource in West Pakistan is its hydroelectric potential. There are also important reserves of natural gas. Coal is found in a number of places but is of low quality. There are also some minor oil fields in the Province. This annex briefly discusses these various domestic sources of energy and the costs of plant to produce electricity from them.

Most of the electricity presently generated in West Pakistan comes from thermal plants fired by natural gas from the Sui field, on the one hand, and the hydroelectric plants in the North, on the other. According to estimates developed in the next section about 45 percent of the electric energy generated in West Pakistan in 1964 was produced from natural gas in plants belonging to the electric utilities, and 40 percent came from WAPDA's hydroelectric plants. Most of the remainder was produced from natural gas in privately owned generators and from imported fuel oil. Coal plays an extremely minor role in the generation of electricity. Details regarding existing generating equipment operated by WAPDA and KESC in the four main grid systems of West Pakistan are given in Appendix Table V.

West Pakistan's Energy Resources

Hydroelectric Resources

West Pakistan's hydroelectric potential has been estimated at ten million kw, but this figure is probably conservative. Less than 250,000 kw have been developed so far. Most of the power programs studied in this report involve the development of about one million kw at Mangla and two million at Tarbela. The hydroelectric resources of the Province and these two projects are discussed in greater detail in Annexes 6 and following.

It is difficult to compare hydroelectric resources directly with mineral fuel resources because of the self-renewing nature of the former. But it is clear that the thermal value of the Province's hydroelectric resources, calculated in terms of the thermal fuel that would be required to generate an equivalent amount of electric power, is large.

If we assume an average 60 percent capacity factor (allowing for seasonal fluctuations in river flows and in heads on the turbines) then the ten million kw estimate of total hydro potential would be equivalent to about 52,000 million kwh or about 600 trillion Btu each year. 1/ The hydroelectric projects included in the program recommended in Chapter VII of Volume IV, together with the existing hydro plant, would by 1985 produce about 20,000 million kwh per year, equivalent to about 240 trillion Btu's.

Mineral Fuel Resources

There is inevitably enormous uncertainty attaching to estimates of mineral fuel reserves, and the figures given below for different fuels cannot be taken as anything more than order-of-magnitude estimates, based on the most recent information available to the Bank Group. The discussion in the following paragraphs is confined largely to mineral fields that are already known to exist as potential sources of energy. There is great uncertainty about the size and quality of these reserves. But there are probably other mineral-fuel reserves in West Pakistan which have not yet been discovered. Moreover technological development may make it possible to tap other potential sources of energy effectively. Research is presently underway in Pakistan, for instance, on the use of solar energy and of the energy of the wind for generation of electricity. However, the approach adopted in the following paragraphs is to try to make a reasonable assessment of fuel reserves that may be considered reliable for purposes of long-term planning.

Natural Gas Reserves

By far the most significant known mineral reserves in West Pakistan are the natural gas fields. Current estimates put recoverable reserves of gas in known fields at about 13 trillion cubic feet. 2/ Some of the fields, however, have gas of very low quality, as can be seen in Table 1, so that total reserves are equivalent to about 10,000 trillion Btu.

1/ Taking an average heat rate of 12,000 Btu per kwh sent out.
2/ Trillion, as used in this report, means million million (10^{12}). The following discussion uses the abbreviations Mcf, meaning 1,000 cubic feet, and MMcf, meaning 1,000,000 cubic feet.

Table 1

West Pakistan Natural Gas Reserves

Field	Net Recoverable Reserves of Raw Gas (in trillion cu. ft.) Est. of Jan. 1960	Est. of Jan. 1965	Standard a/	Main Chemical Components (%) Methane	Dioxide	Nitrogen	Gross Heating Value Btu/cu. ft.
Sui Quality Gas							
Sui	6.00	6.00 b/	5.60	88.5	7.4	2.5	933
Khandkot	0.20	0.20	0.17	79.2	2.5	16.6	842
Mazarani	0.03	0.03	0.03	87.0	0.3	8.0	976
Subtotal	6.23	6.23	5.80				
Other Important Fields							
Dhulian	1.70	1.70	1.87	81.5	0.5	-	1,100
Mari	3.50	1.8 c/	1.30	66.2	9.0	17.0-18.0	725
Sari d/	-	0.3	0.21	n.a.	n.a.	n.a	700
Subtotal	5.20	3.80	3.38				
Local Use Only							
Uch	2.50	2.50	0.77	27.3	46.2	25.2	308
Khairpur	0.25	0.25	0.03	12.2	70.6	16.9	130
Zin	0.10	0.10	0.05	46.1	44.7	8.5	484
Subtotal	2.85	2.85	0.85				
GRAND TOTAL	14.28	12.88	10.03				

a/ Reserves, as estimated in January 1965, converted into standard cubic feet of 1,000 Btu/cu.ft.

b/ An additional 0.3 trillion cu. ft. of reserves was discovered at Sui between 1960 and 1965, but consumption in the period was also about 0.3 trillion cu. ft.

c/ The Third Five Year Plan document gives an estimate of 5 trillion cubic feet for Mari. This appears to be total reserves without allowance for inerts and loss in recovery. Further investigations at Mari have moreover revealed that the field may be less extensive than was then believed and that the conate water saturation may be higher. Recoverable reserves, without risk factor adjustment, are currently estimated at 1.8 trillion cubic feet. (See Text).

d/ Sari Sing field, some 40 miles northeast of Karachi, is still under investigation and it is still unclear what the reserves may turn out to be. The figure used here seems a reasonable guess at this stage of knowledge.

Since sizeable gas fields were first discovered in the early 1950's, two have been developed -- one a relatively small wet field (i.e gas found along with oil) in the north near Rawalpindi, at Dhulian, and the other a large dry field some fifty miles northwest of Gudu Barrage, at Sui. A 347-mile 16-inch pipeline was laid from Sui to Karachi in 1955 and another 217-mile 16-inch pipe from Sui to Multan in 1958. The Multan pipeline has recently been extended to Lyallpur, Lahore and Rawalpindi where it has been linked with the small Dhulian system which has been supplying gas locally since 1957. Out of the total gas sales of about 45 billion cubic feet in 1964 about three billion came from Dhulian and the remainder from Sui; two-thirds of the Sui gas went to the South (chiefly Karachi). Late in 1967 or early in 1968 a third gas field will come into production -- the Mari field, located across the Indus River from Sui, some 40 miles southeast of the Gudu Barrage. Esso Standard (Eastern) is constructing a 175,000-ton urea plant close to the field at Dharki.

Besides Sui, Dhulian and Mari there are a number of other known gas fields in West Pakistan but, according to the engineers who have investigated them, they are either so small or their reserves of such low quality that they are not likely to be useful except for local use or for linking with the existing pipelines. There are two small fields -- one about 30 miles south of Sui, at Khandkot, and the other much smaller and more inaccessible at Mazarani in Larkana District -- which are believed to have gas of sufficient quality that it might be fed into the long-distance transmission lines. Another gas field which has recently been discovered some 40 miles northeast of Karachi, at Sari Sing, appears to fall into this same category of reasonable quality but small reserves (probably between 0.1 and 0.4 trillion cubic feet). The remaining three fields listed on Table 1 under the heading "Local Use Only" have gas which is of too low quality to warrant long-distance transmission. The largest is at Uch, about 30 miles west of Sui; its gas, being about 25 percent nitrogen and 50 percent carbon dioxide, has a heating value of only about 300 Btu/cubic feet. It has been suggested that it might eventually be useful for local production of fertilizers or petrochemicals. The gas in the neighboring Zin field is believed to have a slightly higher heating value but the field is much smaller and would also probably not find more than local usage. The Khairpur gas field is quite extensive but has 70 percent carbon dioxide content which excludes all but local use. Consultants have suggested that it would probably best be reserved for the recovery of carbon dioxide which is used for refrigeration, carbonation and manufacture of a number of chemicals.

The Sari Sing field, though it is small, could come to play a very useful role because of its location close to the largest existing market for gas in West Pakistan. The figure given in Table 1 for reserves at Sari Sing in terms of standard cubic feet (i.e. cubic feet of 1,000 Btu thermal value) is about ten times current annual gas consumption in the Karachi area. Sari could therefore supply the Karachi market for a few years. But, in view of the fact that the pipeline from Sui with peak day capacity of about 110 MMcf already exists, a more rational

use would probably be to use Sari Sing for meeting peak demands and thereby postpone the need for expansion of the pipeline all the way from Sui. Once some of the native gas was removed from the Sari field, it might, moreover, prove feasible to develop the field as a storage reservoir. To be suitable for conversion to storage a gas field must have certain geological characteristics: sufficient permeability to permit high rates of gas injection and withdrawal, good porosity, an overlay of impermeable rock, and an anti-clinical or dome-like structure to permit easy evacuation of the gas from the field. It is not known whether the Sari Sing field has these characteristics, but if it does, then it would probably be appropriate to develop it for storage. This would probably mean that at least 50 percent of the field's own reserves of gas would have to remain in the field as cushion gas, but it would also mean that the Sui-Karachi line would only have to be expanded sufficiently to cope with average-day requirements. Storage potential at Sari would become a particularly valuable asset if the Karachi area was linked by EHV transmission with the hydroelectric plants in the North so that gas requirements for power generation in Karachi would likely become very fluctuating; this matter is discussed in greater detail in subsequent annexes.

Since requirements of thermal fuel for power generation will fluctuate over time even more heavily in the North than in the South, as units are installed at Mangla and Tarbela, it would probably also be attractive to develop any cheap sites for gas storage that may be discovered there. An obvious possibility would be injection of gas at the Dhulian field; under normal circumstances gas injection in a wet field should have the additional advantage of raising the oil output from the field. However Attock Oil Company has apparently investigated the possibility of gas storage at Dhulian and found it technically infeasible. Some consideration has been given to other possible sites for storage in the North, but none has yet been found. As will become clear in Annex 9 the lack of cheap fuel storage facilities in the North will cause WAPDA's thermal fuel supplies to be relatively expensive; further search for cheap gas storage sites in the North would therefore be very worthwhile.

The thermal value of recoverable reserves in the different fields, as currently estimated, is shown in the third column of Table 1 which converts reserves into standard cubic feet of 1,000 Btu/cubic foot thermal value. This column brings out the importance of the Sui field and shows the relative insignificance of the Uch, Khairpur and Zin fields. Dhulian is the second most important field after Zin in terms of total thermal values of reserves. However the rate of off-take from Dhulian is limited by technical conditions to a maximum that is currently taken as about 12 MMcf/day. Mari appears to be the only other major field, but the validity of the reserve estimate is very uncertain; it could be considerably larger and it could be smaller than currently estimated. As the table indicates, the Second Plan document (1960) used an estimate of 3.5 trillion cubic feet and the Third Plan document raised this to 5.0 trillion cubic feet. At that time only three wells had been drilled, of which only one definitely produced gas. Utilization

became an immediate prospect at the end of the Second Plan period and in 1965/66 six more wells were drilled to test the field. One of these wells proved dry and this led to a re-estimate of the areal extent of the field. More importantly, the estimate of the conate water saturation which had before been put at 28 percent was increased, on the basis of a more detailed core analysis of samples from the new wells, to 44 percent. Proven recoverable reserves are now estimated by Esso at 0.64 trillion cubic feet; they represent the estimated content of the drainage basin of the two central wells investigated. Total recoverable hydrocarbons are estimated at 1.8 trillion cubic feet, and this is the figure used in the Table. A more conservative assessment would adjust this figure for greater uncertainties the further the gas is believed to be from the area which has been most fully explored; this would reduce this estimate to 1.2 trillion cubic feet.1/

Apart from the nine structures listed in Table 1, which are known and, at least to some degree tested, there are probably others in West Pakistan. It was estimated in 1959 by engineers who had been involved in exploration activities in the Province that West Pakistan might have additional recoverable natural gas reserves of about 5 trillion cubic feet in structures and traps that had not been tested. Exploratory activity in the interim has not been as intensive as it would have been had a shortage of gas been imminent. However, according to Planning Commission estimates, the Government invested about PRs 177 million during the Second Plan period in prospecting for oil and gas in West Pakistan and private companies, both Pakistani and foreign, invested a further PRs 120 million to the same end. Yet no new fields have been discovered since the above estimate of unknown reserves was made -- with the possible exception of the small Sari Sing field which is still under investigation.

Coal Reserves

The second most important mineral reserve in West Pakistan from the energy point of view is coal. There are a number of fields, most of which have been known for some years and most of which are exploited to some degree; total provincial coal production has increased at a rate of about 10 percent per annum over the last ten years to a 1964 level of about 1.2 million tons. The coal produced is of the semibituminous type, ranging between about 8,000 and 11,000 Btu per lb. It is friable and relatively high in sulphur and ash content, but is

1/ Total hydrocarbons in the Mari field are estimated at 3.3 trillion cubic feet. Deduction of inerts and irrecoverables brings the estimate to 1.8 trillion cubic feet. This is composed of three portions -- Proven reserves, or those in the central portion of the field, Probable reserves, or those estimated on the basis of wells drilled away from the center of the drainage basin, and Possible reserves, or those estimated on the basis of wells drilled at what is believed to be the edge of the field. The figure of 1.2 trillion cubic feet is derived by giving Proven reserves a weight of 100 percent, Probable reserves a weight of 50 percent and Possible reserves a weight of 25 percent.

Table 2

West Pakistan - Coal Reserves

	Estimated Reserves (mln tons)	Thickness of Seams (ft) Max.	Thickness of Seams (ft) Av.	Depth of Seams (ft)	Moisture (%)	Volatile Matter (%)	Fixed Carbon (%)	Ash Content (%)	Sulphur (%)	Calorific Value (Btu/lb)	Btu's (trillion)
Baluchistan and Kalat											
Sor Range)	22				9-14	38-44	43-44	4-6	1-3	10,400-11,900	500
Deghari)					11-14	35-39	42-43	5-12	1-4	9,750-10,800	
Mach	15				7-12	34-39	32-42	10-20	3-7	9,200-10,300	300
Sharigh	40				2-4	35-45	26-44	9-35	5-7	8,500-12,400	900
Punjab-Trans-Indus											
Makerwal	19				3-5	42-48	37-45	6-12	3-6	11,400-12,200	500
Punjab-Cis-Indus											
Salt Range	70				3-8	26-39	30-45	12-38	4-11	7,100-11,100	1,300
Sind											
Jhimpir-Meting	28	9	1.5		15-30	30-40	31-36	8-15	3-7	7,400- 9,800	500
Lakhra	130	8	4	<500	32-36	28-31	27-30	7-11	3-6	7,010- 7,600	2,000
	324									TOTAL	6,000

suitable for direct use in the firing of brick kilns and boilers and for use in the form of coke briquettes in foundries, lime kilns and sugar mills. Some of the most important uses at the present time are for the production of cement at Daudkhel, ammonium sulphate at the Pak-American Fertilizer Plant at the same location, and electricity at the 15-MW Quetta Steam Station (commissioned in September 1964).

Details of the known coal fields in West Pakistan are given in Table 2, which indicates that total reserves may have a thermal value of the order of 6,000 trillion Btu. However, this reserve figure does not appear to be directly comparable with the reserve figure given for natural gas. Reserve figures for gas and oil generally include only deposits which are believed recoverable with present technology and at a price that might make recovery economic within the foreseeable future. By contrast reserve estimates for coal generally cover all known deposits, irrespective of the cost that may be involved in recovery. If West Pakistan's coal reserves were quoted in terms of the same concepts used to define gas reserves they would be substantially less than shown above.

Apart from the coal fields around Quetta, the main field which could become important for power generation, as far as can now be foreseen, is the Lakhra field (some 85 miles northeast of Karachi in Dadu District) which was discovered during the Second Plan period. Table 2 indicates that the quality of coal at Lakhra is lower than in most of the other fields in West Pakistan; it is rather lignite than coal. However, the field is apparently much larger than those previously known and somewhat more accessible. Reserves are currently estimated at 130 million tons; the coal has a high moisture content of about 35 percent. The depth of the seam below the surface is unclear. In a letter to WAPDA the Directorate of Mineral Development of the West Pakistan Government indicates that the coal seam is "not more than 500 feet" below the surface anywhere in the field. According to the Third Plan document the field is already being mined at Lailian and there the seams occur at depths of 80 to 240 feet below the surface.

Oil Reserves

Least significant of the known energy-producing mineral reserves in West Pakistan is oil. The exact extent of the oil reserves is unclear but ECAFE uses an estimate of 27 million barrels -- equivalent to about 160 trillion Btu's in terms of thermal value. This estimate is probably on the low side. At present exploitation is largely confined to four small fields in the Potwar Plateau in the north of the Province -- Dhulian, Khaur, Joya Mair, Karsal and Balkassar. The most important of these is Dhulian, where oil was found in 1937 in the Laki limestone at 7770 feet, in 1952 in the Ranikot limestone 800 feet deeper, and in 1960 in a Jurassic horizon deeper still. The field is exploited by the Attock Oil Company which also operates a refinery at Morgah, near Rawalpindi. Output of refined products at Morgah from Potwar crude has expanded quite rapidly -- reaching about 500,000 tons in 1965 -- or double the 1955 level. 500,000 tons is approximately the full capacity of the refinery.

Since the Potwar oil fields still meet only about 25 percent of total provincial requirements of petroleum products and petroleum imports represent a significant foreign exchange burden, considerable exploration efforts have been made in recent years but they have not resulted in any important discoveries. Prospecting and drilling have been carried out both by private companies and by the Government's Oil and Gas Development Corporation. One of the most hopeful sites identified by surveys undertaken during the Second Plan period was Tut, 90 miles west of Rawalpindi; however, the first well has now reached beyond 13,000 feet without result.

Besides Morgah, West Pakistan has two other oil refineries, both located in Karachi and both using imported crude. The Pakistan Refinery, whose main products are fuel oil, high speed diesel oil, kerosene, motor spirit and jet petroleum, came into operation in 1963. At present it cannot find a market for all of its products in West Pakistan, so that in 1965/66, it exported about $5 million worth of fuel oil and naphtha. The other refinery -- National Refinery -- which is in the public sector and is also located at Korangi close to Karachi was opened in 1966. It has an initial capacity to produce about 0.5 million tons of petroleum products, whereas the Pakistan Refinery has a current capacity of about 2.5 million tons.

Total Mineral Fuel Reserves

Simple addition of the reserve estimates discussed above indicates that West Pakistan has known mineral fuel resources with an estimated thermal value of a little more than 16,000 trillion Btu's. The following summarizes the estimates and compares them with current annual off-takes (further discussed later in this Annex).

Table 3

Current Estimates of Mineral Fuel Reserves and Estimated Annual Current Off-takes

(Trillion (10^{12}) Btu's)

	Reserves	1964 Current Off-take
Natural Gas	10,000	53
Coal	6,000	27
Oil	200	20
	16,200	100

These figures must, however, be treated with great care because, as pointed out above in connection with the coal reserves, the estimates for the different minerals are based on different concepts. Nevertheless, the

table does bring out clearly the dominant position of natural gas; and if figures were available on the fuel reserves which are likely to be economic to recover, this same conclusion would stand out even more clearly.

Even the figure for gas reserves, however, is not free of complications. It seems to be made up of an amalgam of different figures for different fields; for instance, the figure for Mari includes proven, probable and possible reserves, while the figure for Sui apparently represents proven reserves. Moreover, the total figure used above includes fields such as Dhulian, where the daily off-take is limited, and fields such as Uch where location or the quality of the gas may preclude economic exploitation. In view of these uncertainties, we have generally adopted for the purposes of this report one 'firm' figure for readily usable gas reserves -- about 7,200 trillion Btu (including Sui, Mari, Sari Sing, Khandkot and Mazarani) and one 'higher' figure of about 9,500 trillion Btu (on the assumption that an additional 2-3 trillion cubic feet of gas might be discovered at, say, Sui).

The Adequacy of Reserves

If the figures in Table 3 are taken at face value they would imply that West Pakistan has mineral fuel reserves sufficient to cope with the current level of demand for more than 150 years -- and reserves of natural gas sufficient to cope with current demands for gas for nearly 200 years. This would seem extremely ample in the context of the United States, where proven reserves of natural gas for example are currently sufficient to sustain present levels of consumption for only about 15-20 years. There the historical experience of continuing discoveries of additional reserves in developed fields and of new gas fields has generated a high degree of optimism about the country's ability to meet future demands for gas for considerably more than twenty years.

However, there are various characteristics of the situation in West Pakistan which counsel a rather more cautious attitude toward the Province's mineral fuel reserves. In the first place the effects of a shortage in domestic supplies of energy, if it were to occur, would be more severe than it would be in some other countries because of the stringency of the foreign exchange situation in West Pakistan. Indigenous fuel reserves are somewhat limited in range, as has been shown, and West Pakistan still has to meet about a third of its total commercial fuel requirements from imports at present despite considerable efforts at import substitution in this sector. In the second place the demand for commercial fuels is growing very rapidly -- more than 10 percent per annum compared with about 4-5 percent, for instance, in the U.S. -- and this growth may be expected to continue since it is typical for a country at the stage of development now reached by West Pakistan. In the third place there is more uncertainty about the reserve figures used here than about the proven reserve figures mentioned for the United States. Many of the gas structures in Pakistan have been tested with only one or two wells and then held in reserve for a time when an opportunity to use them economically may arise: the reserve estimates

may obviously change substantially when the structures are more fully investigated. Moreover, the recoverability of reserves from a field and the feasible rate of recovery depend on a number of factors, not yet fully known, such as the reservoir pressure. It would be unjustified to infer from the failure to turn up any major new reserves of oil and gas over the last five years that no additional undiscovered reserves exist. Nevertheless this experience does raise doubt about the 1959 estimates of five trillion cubic feet of gas in untested structures which was cited above. As pointed out, the main development of the last five years in connection with natural gas reserves has in fact been a very substantial reduction of the estimates of Mari reserves as a result of further drilling and testing.

Supply Trends and Anticipated Demand

The future demand for electricity has been considered in considerable detail elsewhere in the report, but an essential preface to preparation of a long-term plan for the development of the electric power sector is an examination of the overall balance of supply and demand for energy.

(1) Recent Trends in Commercial Supply of Energy

Two noteworthy features have characterized the growth of energy consumption in West Pakistan in recent years -- the rapidity with which consumption of commercial supplies of energy has grown relative to the rate of growth of GNP and the increasing extent to which this energy has been supplied from domestic sources. ECAFE has estimated that consumption of commercial supplies of energy in the whole of Pakistan grew beteeen 1951 and 1961 at an annual rate of about 7.5 percent -- more than two and a half times the rate of growth of GNP. Some estimates have been compiled from a variety of sources for West Pakistan alone and they are shown in Table 4. Some of the figures are little more than informed guesses, since the data, especially on imports, are extremely deficient. Nevertheless, the figures are reasonable indicators of orders of magnitude. Table 5 represents the same data converted into standard thermal units (British thermal units). It suggests that in West Pakistan the consumption of commercial supplies of energy increased between 1949 and 1964 at an annual rate of better than 10 percent -- or again about two and a half times the rate of growth of GNP. The other important trend which stands out from the recent experience is the extremely rapid rate of growth of domestic production of commercial energy. ECAFE assesses this at 16 percent per annum between 1951 and 1961 on an all-Pakistan basis. Table 5 suggests that the same rate applies to West Pakistan over the period 1949 1964.

The figures in Table 4, however, contrast with ECAFE's estimates in that they suggest that West Pakistan is significantly more self-supporting in energy than Pakistan as a whole. Table 4 shows that West Pakistan met more than 60 percent of its commercial energy requirements from domestic supplies in 1964; ECAFE has a figure of about 40 percent domestic supplies for the whole of Pakistan in 1961. It is quite credible that West Pakistan

should be much more self-supporting than East Pakistan since the West Wing contains the country's main exploited reserves of coal and oil and the development of natural gas production has been much more significant there than in the East. Table 5 brings out the great importance of natural gas among West Pakistan's supplies of energy; it grew in ten years from almost nothing to nearly 30 percent of total commercial energy supplies.

Table 4

Estimated Consumption of Commercial Energy in West Pakistan, a/ 1949-64

	1949	1955	1960	1964
Domestic Sources				
Coal ('000 metric tons)	340	540	830	1,215
Petroleum ('000 metric tons)	130	290	365	500
Natural gas (MMcf)	-	1,380	29,560	53,360
Hydro energy (Mln. kwh)	7	310	540	1,370
Imported				
Coal ('000 metric tons)	600	200	400	300
Petroleum products ('000 metric tons)	160	1,230	1,090	1,400
Energy in form of electricity (Mln kwh)	200	780	1,690	3,390

a/ Excluding petroleum products used as lubricants, but including gas used as feedstock for the production of fertilizer.

Sources: Mainly CSO statistical bulletins and Pakistan trade statistics, supplemented by WAPDA data, Planning Commission documents and various consultants' reports.

Role of Electricity and Primary Sources of Generation

Table 5 suggests that electricity has risen from about 8 percent of total supplies of commercial energy in West Pakistan in 1949 to about 28 percent in 1964. The power consultant estimates total electricity generation in 1964 (including industrially owned generators) at about 3.4 billion kwh. This is equivalent to about 50 trillion Btu's. The primary sources responsible for this generation were mainly natural gas (about 23 trillion Btu's or 40 percent of total gas supply went directly to the power utilities) 1/ and hydro plants (about 20 trillion Btu's, as indicated in Table 5. The main primary source accounting for the remainder was probably petroleum products such as diesel oil and fuel oil. Actual figures are only available on fuel consumption by KESC and WAPDA and they show oil providing only about 1 trillion Btu's. However, most of the industrially owned generating plants belonging to the smaller utilities have been fired by diesel oil, though they are now increasingly converting to natural gas as it becomes available. Coal is a very minor primary source in the generation of electricity; the main coal burning plant in WAPDA's new unit at Quetta which consumed less than 20,000 tons of coal or about 0.25 trillion Btu's in 1964/65.

1/ 20 trillion Btu's of actual sales were to the power utilities. Three are added to cover purification of the gas and shrinkage.

Table 5

The Calorific Value of Commercial Energy Consumed in West Pakistan, 1949-64

(trillion (10^{12}) Btu's)

	1949	1955	1960	1964
Domestic Sources				
Coal	7.5	11.9	18.3	26.7
Petroleum	5.2	11.6	14.6	20.0
Natural Gas	-	1.3	28.8	52.5
Hydro Energy	0.1	4.7	8.1	20.6
Subtotal	12.8	29.5	69.8	119.8
Imported				
Coal	20.8	5.2	10.4	7.8
Petroleum Products a/	6.4	49.2	43.6	56.0
Subtotal	27.2	54.4	54.0	63.8
TOTAL	40.0	83.9	123.8	183.6
of which, electricity	3.0	11.7	25.4	50.9

a/ Including products refined in the Karachi Refinery from imported crude.

Note: The following conversion rates have been used:

domestic coal: 22 mln Btu/metric ton (10,000 Btu/lb.).
domestic & imported petroleum: 40 mln Btu/metric ton
natural gas: Sui gas @ 975 Btu/cu.ft.
Dhulian gas @ 1,100 Btu/cu.ft.
imported coal: 26 mln Btu/metric ton (12,000 Btu/lb.).

Hydro energy is converted into Btu at a rate of 15,000 Btu/kwh which represents approximately the average fuel consumption of generators in West Pakistan per kwh sent out at the present time.

Fuel Imports

The foreign exchange burden of the fuel imports given in Tables 4 and 5 is hard to identify but it is probably in the order of PRs 120 million (about $25 million) or about US cents 40/mln Btu. The Third Plan document states that fuel imported for the whole of Pakistan cost about PRs 446 million in 1963/64. The CSO trade statistics indicate a figure of about PRs 300 million for imports of coal and petroleum products in that year, PRs 200 million for 1964/65 and PRs 210 million for 1965/66. West Pakistan's share of these imports is given as PRs 167 million, PRs 80

million and PRs 83 million in each of these fiscal years, respectively. These figures include non-fuel petroleum products such as lubricating oil and they appear to exclude crude oil imported for production of petroleum products at the refineries in Karachi. Allowing for these items, we can estimate that West Pakistan's foreign exchange bill for fuels in 1964 was about PRs 15 million for coal and coke, and about PRs 105 million for petroleum and petroleum products. Most of the petroleum imports took the form of imports to the refinery. The price of crude oil imported is in the neighborhood of 30 cents/million Btu. Refined petroleum products appear to be imported at much higher prices. The price of imported coal appears to be about 40 cents/million Btu. A total bill of about PRs 120 million for imported fuel would imply that fuel imports made up about three percent of West Pakistan's total imports from abroad (including invisibles) in 1964.

Recent Trends in Total Energy Supply

The figures given so far cover only a relatively small proportion of the total supply of energy in West Pakistan; they exclude non-commercial fuels such as wood, charcoal, cotton stalks and dung which undoubtedly make a very large contribution to the total supply of energy in the Province. Accurate estimates of non-commercial energy supplies are impossible to make Detailed studies of various countries in the Middle East and Asia prepared some years ago 1/ suggest that, of eight countries where data are available, five had consumption levels of about 250 kilograms of coal equivalent (or 6.7 million Btu's) per capita of non-commercial energy in the early 1950's.

What historical evidence is available from different countries suggests that it is reasonable to assume that total energy consumption grows at about the same rate as gross national product. When allowance is made for the increasing efficiency with which primary energy sources such as coal and gas are converted into useful energy, this means that total energy consumption grows slightly faster than GNP. At the same time the composition of the energy consumed tends to shift markedly away from non-commercial sources towards more efficient converters such as coal, oil and gas. The consumption of electricity tends to grow much faster than the consumption of other fuels because of its efficiency, versatility and cleanliness.

What information is available suggests that West Pakistan is no exception to these general trends. Table 6 has been drawn up with the aid of the figures on commercial energy supplies developed in Table 5 and on the basis of the assumption that non-commercial energy supplies were about 6.7 million Btu's per capita in 1949 and have since been growing at about the same rate as the rural population. 2/

1/ M. Hartley, "Energy as a Factor in the Progress of Underdeveloped Countries", Proceedings of the U. N. Conference on New Sources of Energy (Rome, 1961), United Nations, New York, 1963.

2/ Here defined as the population living in places of less than 25,000 inhabitants.

Table 6

Estimate of Total Supply of Energy in West Pakistan, 1949-64

	1949	1955	1960	1964
Total Population (mlns)	34.0	39.6	45.0	49.9
Rural Population (mlns)	29.6	34.0	37.6	40.6
Energy (trillion Btu's)				
Non-commercial	230	264	292	315
Commercial	40	84	124	184
TOTAL	270	348	416	499
GPP (PRs bln, 1959/60 prices)[a]	11.6	14.2	16.6	20.8
Energy per capita (mln Btu's)	7.9	8.8	9.2	10.0
Electricity per capita (kwh)	6.0	20.0	38.0	68.0
Electricity as % of total energy	1.1	3.4	6.1	10.2

a/ See Economic Annex for estimate of Gross Provincial Product.

The resultant estimates of total energy consumption suggest that it has been growing at about the same rate as the Gross Provincial Product of West Pakistan, in constant price terms. The table also indicates the rapidly increasing share of electricity in the total supply of energy in the Province.

(2) Future Trends

(a) Future Trends in the Demand for Energy

On the basis of the figures worked up in Table 6 and with the assumption that supplies of non-commercial energy will continue to increase at about the same rate as rural population, it is possible to make some rough estimates of the future demand for commercial energy that is implied by Pakistan's Perspective Plan. The GPP growth rate for West Pakistan envisaged in the Perspective Plan is about 6 percent per annum. Table 7 which parallels Table 6 except that demand for commercial energy is derived as a residual is based on this rate of growth in provincial product. These figures suggest that demand for commercial supplies of energy may increase at an average rate of nearly 9.5 percent per annum over the Perspective Plan period. Total demand for energy may increase from about 10 million Btu per capita in 1964 to nearly 20 million Btu per capita in 1985. Commercial energy requirement may rise from about 37 percent of the total in 1964 to over 70 percent of the total in 1985. The last two lines of the table are based on the

main power load forecasts that have been used in these studies (see Table 47 of Chapter IV of the Power Volume). They suggest that the per capita demand for electricity may increase about four and a half times between 1964 and 1985 and that electricity, even with allowance for substantial improvement in the average effficiency of thermal generation, may increase from about 10 percent of total energy requirements in 1964 to more than 20 percent in 1985.

Table 7

Projection of Demand for Energy in West Pakistan, 1964-85

	1964	1970	1975	1980	1985
Total population (mlns)a/	49.9	58.3	67.0	78.0	89.0
Rural population (mlns)	40.6	45.7	50.7	57.0	62.1
GPP (PRs blns, 1959/60 prices)a/	20.8	29.2	39.7	55.4	71.9
Energy (trillion Btu's)					
Total	499	710	950	1270	1700
Non-commercial	315	355	394	441	480
Commercial	184	355	556	829	1220
Energy per capita (mln Btu's)	10.0	12.2	14.2	16.3	19.1
Electricity per capita (kwh)	68.0	130.0	197.0	258.0	331.0
Electricity as % of total energyb/	10.2	15.0	18.0	20.6	20.8

a/ See Economic Annex for population and income projections.
b/ Growth of electricity appears smaller here than in preceding line because of the assumption that average heat rates per kwh sent out will improve from about 15,000 Btu in 1964 to about 12,000 Btu per kwh sent out in 1985.

(b) The Future Supply of Energy

The first section above gave some details of the current estimates of West Pakistan's energy reserves and Table 5 indicated trends in the supply of different forms of energy. Therefore it is possible to use what is currently known about West Pakistan's energy situation to make some rough predictions as to the primary sources of energy that will meet the demands projected above.

Special attention will be given to natural gas because of its predominant importance among West Pakistan's mineral fuel reserves and because its use has been growing much more rapidly than that of any

other fuel. It has significant operating advantages over other fuels and a wide range of potential uses. It is, moreover, the main existing and potential alternative to water as a primary source of electricity generation.

The Use of Natural Gas

The main consumers of gas to date have been the power utilities and the second most important consumer has been the cement industry. Most of the cement plants in West Pakistan now use gas for firing their kilns. Table 8 indicates the pattern of gas consumption in 1964.

Table 8

Natural Gas Sales in West Pakistan, 1964
(MMcf)

Industry	Sui	Dhulian	Total	% of Total
Power	19,666	618	20,284	45.1
Cement	7,923	1,909	9,832	21.8
Fertilizer	2,635	---	2,635	5.9
Other Ind.[a]	10,605	784	11,389	25.3
Commercial	538	3	541	1.2
Domestic	351	1	352	0.7
	41,718	3,315	45,033	100.0

a/ Approximately 50% of these sales are to the textile industry. Glass industry accounts for about 20% of sales to other industries.

The current pattern of consumption fails to bring out the importance of gas to many industries. Gas has significant operating advantages for a number of industries,[1] but it is especially important in the production of certain goods for which it is used not only for its heating value but also for its chemical content. By far the most important of these goods at the current stage of development in West Pakistan is fertilizer, for which demand in the Province is growing rapidly. At present the use of gas for production of fertilizer is confined to the relatively small Multan plant which produces ammonium nitrate and urea.

1/ Even where natural gas is used purely for heating purposes it can have substantial advantages over other fuels. A.U. Loan reports, for example, that experiments carried out prior to and after the conversion of the Indus Glass Factory at Hyderabad and the Crescent Glass Factory in Karachi from oil to gas established that to make one ton of glass requires 19.4 million Btu's with furnace oil and only 12.3 million Btu's with Sui gas. (A.U.Loan, "The Last Ten Years of Natural Gas in Pakistan," November 1965).

However, gas of the quality available at Sui and Mari is very suitable for the manufacture of nitrogenous fertilizer. A large urea plant is currently under construction at Dharki close to Mari and three or four additional nitrogenous fertilizer projects are in the planning stage. Another potential priority use for gas is in the production of petrochemicals. Known natural gas reserves are lean -- they have a relatively small proportion of the heavier hydrocarbons such as methane and propane in their chemical composition -- and, since haphtha and refinery gas will continue to be available from the Karachi refineries, it will probably not be economical to use the natural gas to produce ethylene, the basis of one large range of chemical products. However, both Sui and Mari gas have quite high methane content and methane can be transformed into acetylene which is the basis of a wide range of chemicals, such as polyvinylchloride, polyacrylonitrile, methanol and polyacetates. In addition the gas could be used, in conjunction with urea from, say, the Multan plant to manufacture urea formaldehyde, plastic and adhesives. Some of these goods are already being produced from Sui gas and there are plans for producing others which will no doubt be executed when the market for them looks sufficiently large to justify plants of economic size. These uses of gas are obviously important because of the peculiar advantages of gas as a basis for production of certain petrochemicals, but the bulk of the growth in demand for gas will come from the fertilizer industry and from general industrial consumers.

Projection of Non-Electrical Demand for Natural Gas

To provide a firmer picture of the potential role of natural gas in meeting future energy demands, and to gain insight into the extent to which gas may be used for generation of electricity without prejudicing its availability to other consumers, detailed projections have been made of non-electrical demand for gas in West Pakistan up to 1985. These projections are based on those prepared by the gas transmission companies, Sui Gas Transmission Company (and the distribution companies, Karachi Gas and Indus Gas) for the Southern region and Sui Northern Gas Pipelines Limited for the North. Their projections are made largely for purposes of financial planning and so they tend to the conservative. To ensure that adequate allowance is made for the growth of demand for natural gas for purposes other than power generation we have adopted the higher versions of their projections (e.g. those of KGC and IGC rather than of SGTC for the South) and we have further adjusted them by making special allowance for increases in consumption by major gas consuming industries (e.g. cement and fertilizer) in the long run. Appendix Tables I and II represent these adjusted versions of the gas companies projections (omitting the electric utilities). Besides expansion of existing fertilizer plants, plans also exist to construct additional fertilizer capacity. This capacity will be needed to meet the projection of fertilizer requirements given elsewhere in this report and so a further allowance must be made in the gas projections to accommodate these plants. Appendix Table III is a projection of fertilizer production designed to do somewhat better than meet the minimum target of supplying about 30 lbs. of nitrogen per acre on

110 percent of total cultivated acreage of 30 million acres in 1975 and 50 lbs. of nitrogen per acre on 140 percent of total cultivated acreage of 30 million acres in 1985. The last two lines of Appendix Table III, under the heading "Additional Capacity Required" indicate the fertilizer plants anticipated whose gas requirements are not included in Appendix Tables I and II. One 400,000-ton urea plant (184,000 tons of N) is indicated for Khandkot because the Government plans a plant there. Two other 500,000-ton urea plants (230,000 tons of N) are indicated for Mari/Sui. The gas requirements of these plants, in terms of Sui-quality gas (about 60,000 cu.ft. of Sui gas per ton of N excluding gas required for electric supply)1/ would be about 30 MMcf/day in 1975, 70 MMcf/day in 1980 and a little over 100 MMcf/day in 1985.

These various calculations are summarized in Table 9 below which indicates 1964 average daily sales of Sui gas to entities other than the electric utilities and shows the projections for the key years 1970, 1975, 1980 and 1985.

Table 9

Average Day Sales of Sui Gas (excl. sales to Electric Utilities)a/ 1964-85
(MMcf/day)

Average Daily Sales (MMcf/day)	1964	1970	1975	1980	1985
SNGPL	12	54	164	210	270
SGTC	49	102	165	222	296
Add'l Fertilizer Projects	-	-	30	70	105
TOTAL	61	156	359	502	671
Annual Total ('000 MMcf)	22.3	56.9	131.0	183.0	245.0
Sui Gas Off-take('000 MMcf)b/	25.2	64.3	148.0	207.0	277.0
Thermal Value c/ (10^{12} Btu) d/	25.0	63.0	144.0	202.0	270.0

a/ All figures are given net of availability from Dhulian assumed to be 12 MMcf/day.
b/ Off-take represents line 5 increased 13% to allow for purification and compression fuel, etc.
c/ Thermal value taken at 975 Btu/cu.ft.
d/ (10^{12} Btu = Trillion Btu).

This table does not indicate the full contribution that natural gas may make toward meeting energy requirements in coming years. There are two additional small items which have to be taken into account, apart from sales to electrical utilities.

1/ 60,000 cu.ft./long ton of N is less than the consumption of the existing fertilizer plants in West Pakistan. Their requirements are about 80,000 cu.ft. of Sui gas/long ton of N. New plants should be more efficient.

One is the contribution of the Dhulian field, off-take from which is limited by technical factors as pointed out before to a daily average of 12 MMcf. On this basis consumption from this field might rise from about 4 trillion Btu's in 1964 to about 5 trillion Btu's annually. The table also omits some fertilizer production. For the sake of simplicity, rather than to indicate reality, the assumption has been made that all new fertilizer plants will be based on Sui gas. However, as pointed out above, there is already one fertilizer plant under construction close to Mari. This plant will have a capacity of 175,000 tons of urea per year or about 80,000 tons of N. The requirement of Mari gas per ton of N, excluding requirements for generation of electricity, is about 80,000 cubic feet or 60 million Btu's. Therefore, this plant will require about 5 trillion Btu's per annum for feedstock and reformer furnace. These two small items are additional to the figures in Table 9.

Other Energy Sources

The main existing sources of commercial energy apart from gas are imported fuels, coal and oil. It is hard to foresee how supplies of these will develop. Demand for petroleum products will undoubtedly grow rapidly and the estimate of oil reserves given in the first section suggests that it will not be possible to increase domestic production to meet demand. Indeed currently estimated reserves of oil are insufficient to sustain present production for more than about ten years. But if it is assumed that these reserves are underestimated so that at least the current level of production could be maintained, then domestic petroleum production might continue to contribute 20 trillion Btu's a year through 1985 to meet domestic energy requirements. Little is known about the potential for increasing the production and consumption of coal. However, coal production has been growing quite rapidly in recent years -- at about 10 percent per annum since 1950 -- and estimated recoverable reserves are sufficient to sustain this increase for some time. We might assume therefore that coal supplies will continue to increase at about 10 percent per annum. Finally, there is imported fuel. Tables 4 and 5 indicated a sharp decline over the last ten years in imported fuels' share of the total energy market in West Pakistan. Nevertheless in absolute terms fuel imports have continued to grow. It was estimated above that they constituted about 3 percent of total imports from abroad in 1964 and that the average price was about 40 cents/mln Btu. It is assumed, for present purposes, that West Pakistan will continue to spend about 3 percent of available foreign exchange on fuel imports and that the average price of this fuel will gradually decline1/ as more of the imported energy takes the form of crude oil for production of refined products at the Karachi refineries. Then we can make an estimate of the potential contribution to energy supplies from this source over the next twenty years. These estimates are drawn together on page 23 below.

1/ Actual assumption made here is that average price of imported fuel will decline as follows: 1964 -- 40¢ per mln. Btu; 1970 -- 38¢; 1975 -- 36¢; 1980 -- 34¢; 1985 -- 32¢.

(3) Costs of Potential New Generating Equipment

In discussing plans for the future the economics of various types of generating equipment are considered. The hydroelectric projects which have been studied, and their installations, are described in Annex 6. As regards plants which could use mineral fuels to produce electricity, attention was mainly concentrated on gas turbines and steam boiler turbines, each of which could use either gas or fuel oil as a primary fuel, and nuclear units. Some attention was also given to coal burning generators. Capital costs of these different types of equipment differ markedly and the figures used in the studies described in the following annexes were taken directly from the power consultant. He based his cost estimates on recent experience in West Pakistan and where this was inadequate (as, for instance, in the case of steam turbines above 150 mw in size) he used U.S. prices modified to reflect costs in West Pakistan.

Table 10 lists some of the salient data regarding thermal and nuclear plants which were used in these studies. All costs are given in U.S. dollars(converted, where appropriate, at the official current exchange rate of U.S. $1 = PRs 4.76) and in terms of 'economic' prices (i.e. excluding duties, taxes and interest during construction). The costs cover equipment to the low side of station transformers, i.e. up to, but not including, the equipment which raises it to a voltage appropriate for transmission purposes. Further details about the costs and characteristics of thermal generating units used for this report are given in Appendix Tables IV-VI.

Nuclear Possibilities

As far as can be foreseen nuclear plants in West Pakistan would have to rely on imported fuel. The Pakistan Government has, in fact, signed a contract for one nuclear unit which is scheduled to be completed by 1971 near to Karachi. The unit, which will be manufactured by Canadian General Electric, will have a net capacity of 125 mw. It will be run by the Pakistan Atomic Energy Commission, partly for research purposes. Energy will be sold to KESC at a rate of 7.3 U.S. mills per kwh. The potential nuclear units for which details are given in Table 10 are of larger size and more economical; they have been considered strictly from the point of view of their competitiveness with alternative means of generating electricity. The nuclear estimates given in Table 10 assume the use of either boiling water or pressurized water reactors. The power consultant included about $1 million in his cost estimate for a nuclear plant to cover additional costs involved in providing security against earthquakes. The power consultant states that the Pakistan Western Railway could probably not at present carry the reactor for a 200-mw nuclear unit and he points out that sea transport for such a unit would also generally be expensive because it would involve chartering a vessel. He points out that technological change in the matter of nuclear generation and expansion

Table 10

Some Characteristics of Typical Potential Generating Units in West Pakistan

TYPE OF UNIT	Size (mw. net)	Capital Cost ($/net kw) Foreign	Domestic	Total	Time Required for Construction (Yrs.)	Operating and Maintenance Cost ($/kw/year.)	Gross Heat Rate (Btu/kwh sent out)
Gas/Oil							
Gas Turbine	13	92	15	107	3	3.0	17,500
Steam Turbine	100	124	31	155	4	2.6	11,500
Steam Turbine	150	114	29	143	4	2.0	11,300
Steam Turbine	200	116	25	141	4	1.7	10,700
Coal							
Steam Turbine a/	200	156	34	190	4	3.25	10,700
Nuclear b/							
	200	193	40	233	5	3.7	0.0020
	400	140	29	169	5	2.0	0.0016

a/ Including ash-disposal facilities, etc.
b/ 'Heat Rate' for Nuclear Units are given in U.S. Dollars fuel cost per kwh sent out, assuming approximately an 80 percent load factor.

and improvement of the Pakistan Western Railway will probably change these conditions. At the present time, there are apparently other obstacles to the development of nuclear units of economic size in West Pakistan; it is doubtful whether the heavy on-site welding required as a result of shipment of the unit in pieces from overseas could be accomplished in West Pakistan, and a great many of the special components required for a nuclear plant would have to be imported. However, quite apart from these physical difficulties, it is unlikely that a large-size nuclear unit in West Pakistan could obtain a sufficiently high load factor over the next 10-15 years to be competitive with other sources of generation.

(4) The Overall Energy Balance

On the basis of these projections and assumptions it is possible to draw up a rough fuel balance sheet for the Perspective Plan period. Lines 1-3 of Table 11 show total energy requirements, non-commercial supplies and, as a residual item, requirements of commercial energy (see Table 7). Lines 4-6 indicate the contributions of the various thermal fuels discussed above to meeting commercial energy requirements. Line 7 is based on information developed in subsequent annexes and indicates the hydroelectric contribution to total energy supplies implied by a program which includes the completion of Tarbela in 1975. Line 8 is also based on the power program which includes Tarbela in 1975 and is recommended in this report; it represents approximately the draft on the Province's natural gas resources that might be made in the various years by the electric utilities. Line 10 is added from the discussion on page 20, allowing imports of fuel to grow at 3 percent per annum. Line 12 is the residual. Line 13 is for comparative purposes; it indicates the amount of energy that will be consumed in the form of electricity according to the Main Load Forecast used in these studies.

The table suggests that it is possible to foresee a reasonable balance in the supply and demand for energy in West Pakistan over the Perspective Plan period. However, the 'gap' which is the amount of energy apparently required to meet the targets of the Perspective Plan, the source of which cannot be foreseen, grows quite rapidly so that by the end of the Plan period it is of the same order of magnitude as total energy imports. The table indicates the dynamic growth in natural gas that can be anticipated: from about 10 percent of total energy supplies in 1964 to about 20 percent of total energy supplies in 1985. If Tarbela were not in existence by 1985 and gas-fired thermal plants were supplying approximately the energy contribution that is assumed in the above table to come from Tarbela in that year, then gas would be providing an additional 120 trillion Btu's or altogether 27 percent of total energy requirements.

Figure 1, following the table, represents in pictorial form the past history shown in Table 5 and the projections shown in Table 11.

Table 11

Projections of Energy Requirements and Supplies, 1964-85
(trillion Btu's)

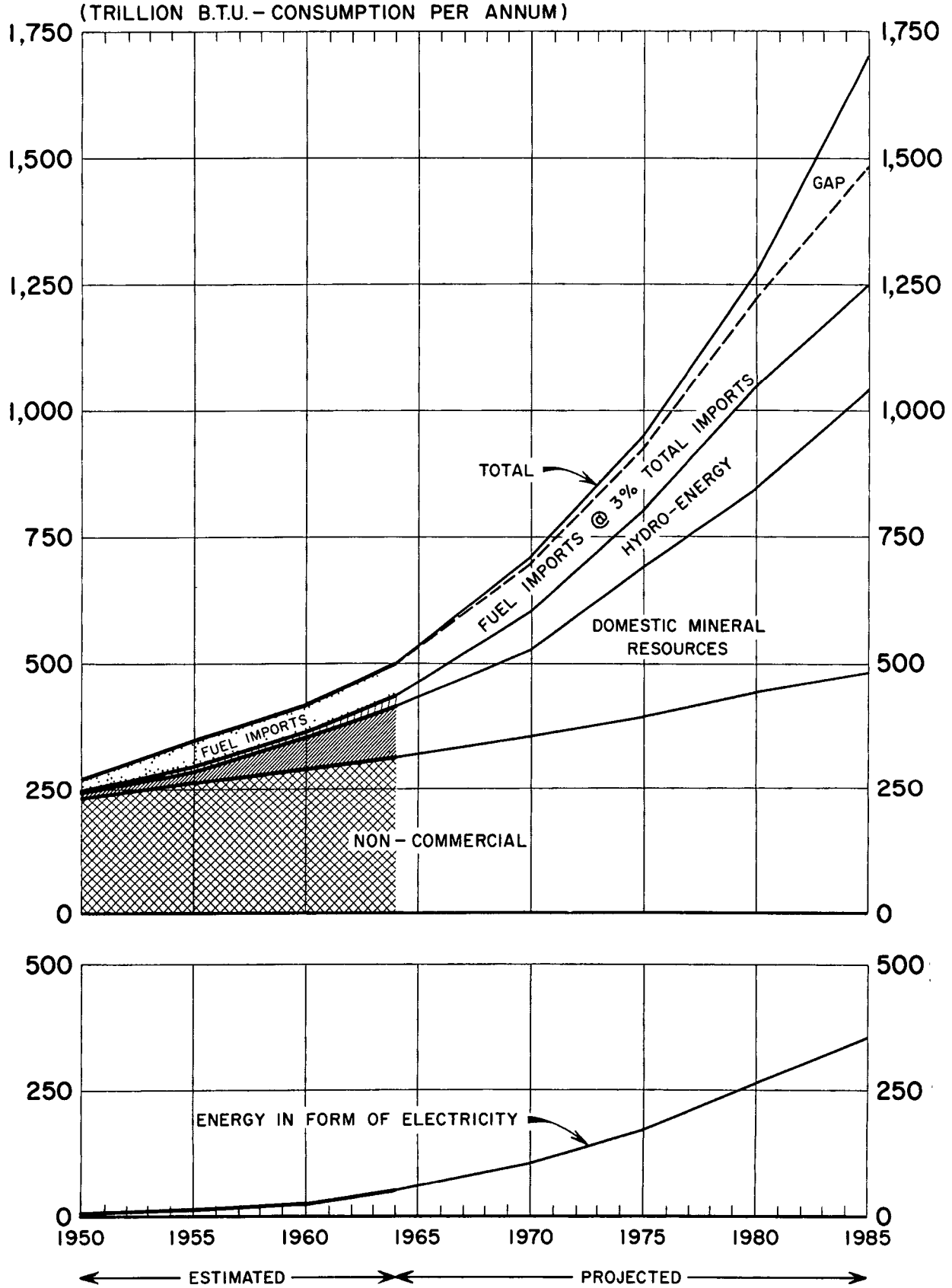
		1964	1970	1975	1980	1985
1.	Total Requirements	499	210	950	1270	1700
2.	Non-commercial	315	355	394	441	480
3.	Commercial Requirements	184	355	556	829	1220
	Commercial Supplies					
4.	Natural Gas (Non-electric)	30	73	154	212	280
5.	Domestic Coal	27	47	76	123	200
6.	Domestic Petroleum	20	20	20	20	20
7.	Hydro a/	20	74	110	200	213
8.	Gas (Electric utilities)	23	30	45	50	55
9.	Total Domestic	120	244	405	605	768
10.	Imports	64	96	126	175	230
11.	Total Commercial	184	340	531	780	998
12.	Energy Gap	-	15	25	49	222
13.	Energy Consumption in form of electricity b/	(58)	(103)	(199)	(262)	(335)

a/ The energy contribution from hydroelectric plant is calculated on the basis of conversion rates which are supposed to represent approximately the average efficiency of thermal generation in West Pakistan at the various dates, i.e. 1964-15,000 Btu/kwh, 1970-14,000 Btu/kwh, 1975-13,000 Btu/kwh, 1980-13,000 Btu/kwh, 1985-12,000 Btu/kwh.

b/ Based on Table 47 in main Power Volume of this report: includes industrial generation as well as utilities' generation. It is converted into thermal value at the rates indicated in footnote a/.

ROLE OF DIFFERENT PRIMARY ENERGY SOURCES IN MEETING WEST PAKISTAN'S ENERGY NEEDS, ESTIMATED AND PROJECTED

(TRILLION B.T.U. – CONSUMPTION PER ANNUM)



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Appendix Table I

Long-Term Projections of Non-Electrical Demand for Sui Gas -- SNGPL[1/]
(MMcf/average day)

		1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Rahimyar Khan:	Other	0.7	0.8	0.9	1.0	1.0	1.1	1.2	1.4	1.5	1.7	1.8	2.0	2.2	2.5	2.6	2.9	3.0	3.3	3.6	3.8
Multan:	Fertilizer	7.2	7.2	7.2	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
	Other	4.7	5.2	5.7	6.2	6.9	7.6	8.4	9.2	10.1	11.1	12.3	13.5	14.8	16.2	17.5	18.7	20.3	21.7	23.3	25.1
Lyallpur:	Other	5.2	5.6	6.2	6.8	7.4	8.2	9.0	9.9	10.9	12.0	13.2	14.6	16.0	17.6	18.9	20.3	21.9	23.5	25.3	27.2
Lahore:	Other	2.6	2.8	3.0	3.3	3.7	4.1	4.5	5.0	5.4	5.9	6.5	7.1	7.8	8.6	9.3	10.0	10.7	11.5	12.4	13.3
Kala Shah Kaku:	Other	2.6	2.8	3.0	3.3	3.7	4.1	4.5	5.0	5.4	5.9	6.5	7.1	7.8	8.6	9.3	10.0	10.7	11.5	12.4	13.3
Gujranwala:	Other						1.8	1.9	2.1	2.3	2.6	2.8	3.0	3.3	3.7	4.0	4.3	4.6	4.9	5.3	5.7
Gharibwal:	Cement	6.4	6.4	6.4	9.6	9.6	9.6	10.3	11.1	11.8	12.6	13.5	14.5	15.5	16.6	17.7	18.9	20.2	21.8	23.2	24.8
Dandot:	Cement	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Rawalpindi/Wah:	Other	3.0	3.2	7.0	7.7	8.5	9.4	10.3	11.4	12.5	13.8	15.0	16.6	18.2	20.0	21.5	23.1	24.9	26.7	28.7	30.9
	Cement	8.8	8.8	12.0	12.0	12.0	18.4	18.4	18.4	19.3	20.7	22.1	23.6	25.2	26.9	29.0	30.9	33.0	35.6	38.5	41.4
Khewra:	Soda Ash	1.6	1.6	1.6	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Sargodha/Bhalwal:	Other						0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9
Daudkhel/Kalabagh:	Other						0.5	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8
	Cement						4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
	Fertilizer						23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
	Steel						4.8	4.8	4.8	4.8	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Other on Route							1.5	3.9	3.9	3.9	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Kohat:	Cement							2.4	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Peshawar:	Other							11.7	12.3	12.8	19.2	19.6	19.9	20.2	20.6	21.0	21.5	22.0	22.5	23.1	23.7
TOTAL		44.4	46.0	54.6	63.5	66.4	113.2	134.1	142.2	148.6	175.9	183.9	192.7	202.0	212.5	222.2	232.2	243.1	255.0	268.0	281.6
Available from Dhullian		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Demand for Sui		32.4	34.0	42.6	51.5	54.4	101.2	122.1	130.2	136.6	163.9	171.9	180.7	190.0	200.5	210.2	220.2	231.1	243.0	256.0	269.6
Total Consumption Sui ('000 MMcf)		11.8	12.4	15.5	18.8	19.9	36.9	44.6	47.5	49.9	59.8	62.7	66.0	69.4	73.2	76.7	80.4	84.4	88.7	93.4	98.4

1/ Taken from sales forecast of SNGPL, November 1966, with adjustment to figures for cement in the Gharibwal and Rawalpindi/Wah areas to allow for growth at the rate of 7% p.a. from the early 1970's on and adjustment to the figure for the Daudkhel fertilizer plant to allow for its planned expansion in 1970/71 to 175,000 tons of N p.a.

Appendix Table II

Long-Term Projections of Non-Electrical Demand for Sui Gas -- SGTC[1]
(MMcf/average day)

		1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Karachi:	Cement[2]	9.0	9.0	9.0	9.0	10.9	13.0	12.8	12.8	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
	Other Ind.	30.0	31.5	34.1	37.2	42.1	44.9	47.7	50.2	53.0	55.6	58.3	61.0	64.0	67.0	70.0	73.5	77.0	80.5	84.5	88.5
	Commercial	2.0	2.1	2.3	2.5	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	4.0	4.3	4.7	5.0	5.4	5.8	6.2	6.6
	Domestic	1.4	1.7	2.0	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.8	5.2	5.6	6.0	6.4	6.8	7.2	7.6
	Steel Mill[3]						13.0	28.0	29.0	29.0	31.0	33.0	35.0	37.0	40.0	43.0	46.0	49.0	52.0	56.0	60.0
Indus:	Zeal Pak[2]	13.5	13.5	23.2	29.0	29.0	31.4	32.1	34.2	36.6	39.3	42.0	45.0	48.3	51.6	55.2	59.1	62.9	67.3	72.3	77.3
	ACC, Rohri[2]	2.4	2.4	2.4	2.4	2.4															
	Other	5.5	6.3	8.8	10.9	12.0	13.2	14.5	15.9	17.5	19.2	21.1	23.5	25.9	28.2	31.0	33.3	35.6	38.5	40.8	43.5
		63.8	66.5	81.8	93.3	101.6	121.1	141.2	148.6	155.5	165.0	174.7	185.3	196.6	208.9	222.1	235.5	248.9	263.5	279.6	296.1
Total Consumption ('000 MMcf)		23.3	24.3	29.9	34.1	37.1	44.2	51.5	54.2	56.8	60.2	63.8	67.6	71.8	76.3	81.1	86.0	90.8	96.2	102.0	108.0

1/ Based on November 1966 sales projections by the Karachi Gas Company and the Indus Gas Company for the period 1967-76; figures for the period 1976-85 have been derived on the assumption that the growth rates of the first decade will be largely sustained.

2/ For the sake of convenience, rather than to represent reality, all growth of the cement industry after 1970 is assumed to take place in the Sind, where gas consumption for manufacture of cement is assumed to increase 7% a year.

3/ Including, initially 21.5 MMcf per day generation of electricity in a power plant of 120 MW and 7.4 MMcf per day for other purposes, and increasing from 1975 at about 7% per annum.

Appendix Table III

LONG-TERM PROJECTION OF FERTILIZER PRODUCTION
('000 tons of N per annum)

	1966	1967	1968	1969	1970	1971	1972	1976	1983
Existing Capacity & Planned Expansion									
Daukhel: Ammonium Sulphate (1 ton $(NH_4)_2SO_4$ = 0.21 ton N)	10.5	10.5	10.5	19.0	19.0	19.0	19.0---	19.0---	19.0
Multan: Calcium Ammonium Nitrate (1 ton NH_4NO_3 $CaCO_3$ = 0.26 ton N)	26.8	26.8	42.4	42.4	42.4	42.4	42.4---	42.4---	42.4
Urea (1 ton CO N_2H_4 = 0.46 ton N)	27.2	27.2	34.0	34.0	34.0	34.0	34.0---	34.0---	34.0
Planned New Capacity									
Mari-Esso: Urea (1 ton CO N_2H_4 - 0.46 ton N)	-	-	40.0	80.0	80.0	80.0	80.0---	80.0---	80.0
Daudkhel: Ammonium Sulphate Nitrate (1 ton $(NH_4)_2SO_4$ NH_4 NO_3 = 0.26 ton N)					78.0	156.0	156.0--	156.0--	156.0
Additional Capacity Required									
Kandkhot: Urea						92.0	184.0--	184.0--	184.0
Mari/Sui: Urea								230.0--	460.0
	64.5	64.5	120.1	175.4	253.4	423.4	515.4--	745.4--	975.4

1/ This table differs slightly from Appendix Table V in Annex 2 because this one was prepared at a later date. The projections of fertilizer output after 1970 are somewhat lower in this table than given in Annex 2.

Appendix Table IV

THE CAPITAL COST OF TYPICAL POTENTIAL NEW THERMAL UNITS
($/kw installed)

	Capability (mw)	Capital Costs (Economic a/)			
		Fx	Dom.	Total	Fx %
Lyallpur 1	100	124	31	155	80
Lyallpur P b/	100	84	21	105	77
Lyallpur 5	150	114	29	143	80
Lyallpur 6	200	116	25	141	82
Lyallpur 8	300	107	22	129	83
Lyallpur N1 c/	300	174	36	210	83
Lahore GT d/	26	92	15	107	86
Hyderabad GT 2	26	92	15	107	86
Korangi 3	125	98	26	124	79
Korangi 5	200	116	25	141	82
Korangi 7	300	100	26	126	79
Karachi N1	125	351	72	423	83
Karachi N2	200	193	40	233	83
Karachi N3	400	140	29	169	83
Mari 1	100	124	31	155	80
Mari P	200	84	21	105	77
Mari 3	150	114	29	143	80
Mari 6	200	116	25	141	82

a/ Excluding taxes, duties and interest during construction.
b/ "P" refers to peaking units (gas turbines) at $105 per kw installed. All units with only a number attached are regular steam units.
c/ "N" refers to nuclear units.
d/ "GT" refers to gas turbines.

Appendix Table V

OPERATIONAL CHARACTERISTICS OF EXISTING THERMAL CAPACITY, AS USED IN COMPUTER STUDIES

Existing Plants (or under construction)	Net Capability (mw)	O & M Cost ($/kw/yr.)	Gross Heat Rate (Btu/kwh)	% of Fuel Imported	'Financial' Fuel Price a/ (¢/mln.Btu)
Multan S1	124	2.3	11,800	-	50
Multan S2	124	2.3	11,800	-	50
Multan GT	6	4.0	14,800	-	50
Lyallpur S1	10	14.0	11,500	50	74
Lyallpur D	7	14.0	11,500	50	74
Montgomery S	5	14.0	11,500	50	74
Lahore GT1	26	3.0	18,000	-	50
Lahore GT2	26	3.0	18,000	-	50
Lyallpur S	124	2.3	11,500	-	50
Karachi A	15	6.5	24,000	-	36
Karachi B	25	5.5	18,000	-	36
Karachi BX	60	2.7	12,700	-	36
Karachi Elander	5	14.0	11,500	80	80
Karachi DF	15	8.0	11,400	20	40
Korangi 1	66	2.3	11,300	-	36
Korangi 2	66	2.3	11,300	-	36
Hyderabad S1 b/	22	3.5	16,000	-	44
Hyderabad S2	15	3.0	13,000	-	44
Hyderabad GT	6	3.0	24,000	-	44
Sukkur	50	3.0	13,000	-	44
Kotri OFT c/	12	3.3	14,000	-	50
Kotri GT	40	3.0	18,000	-	44

a/ i.e., "fuel price 1" in the computer print-outs; this is supposed to correspond approximately to the current structure of fuel prices in West Pakistan.

b/ In fact, a combination of a diesel plant at Jamshoro with three 375-kw units; the old steam electric station with a 1938 unit rated 1,600 kw and a 1951 unit rated 3,600 kw (boiler limitations reduce the combination to a peak of 2.9 mw); and a new thermal plant having two 7.5-mw steam units and one 7.0-mw gas turbine with a combined net capability of 20.1 mw. The power consultant estimates the net capability of this combination at 23 mw. Coming on line in 1966/67 are one 15-mw steam unit (Hyderabad S2 above) and one 8-mw gas turbine (Hyderabad GT above). 3 mw of capability at the old station are expected to be retired by 1968. Therefore, we have adopted a total net capability for 'existing' plants in Hyderabad of 43 mw (22+15+6).

c/ Oil-fired turbine.

Appendix Table VI

OPERATIONAL CHARACTERISTICS OF TYPICAL POTENTIAL NEW THERMAL UNITS, AS USED IN COMPUTER STUDIES

	Net Capability (mw)	O & M Cost ($/kw/yr.)	Gross Heat Rate (Btu/kwh)	% of Fuel Imported	'Financial' Fuel Price (¢/mln.Btu)
Lyallpur 1	100	2.6	11,500	-	50
Lyallpur P	100	2.8	17,500	-	50
Lyallpur 5	150	2.0	11,300	-	50
Lyallpur 6	200	1.7	10,700	-	50
Lyallpur 8	300	1.5	10,400	-	50
Lyallpur N1 a/	300	3.0	0.0022	85	-
Lahore GT3	26	3.0	17,500	-	50
Hyderabad GT2	26	3.0	17,500	-	44
Korangi 3	125	2.5	11,300	-	36
Korangi 5	200	1.7	10,700	-	36
Korangi 7	300	1.6	10,000	-	36
Karachi M1 a/	125	5.0	0.0020	90	-
Karachi N2 a/	200	3.7	0.0020	90	-
Karachi N3 a/	400	2.0	0.0016	90	-
Mari 1 b/	100	2.6	12,000	-	14
Mari P	200	3.0	18,000	-	14
Mari 3	150	2.0	11,800	-	14
Mari 6	200	1.7	11,600	-	14

a/ "Heat Rates" on nuclear plants are given in U.S. cents per kwh.
b/ Heat Rates on Mari plant are set somewhat higher than those on Sui-fired plants of equivalent size because of the lower quality of Mari gas (see Kuljian Corporation, "Report for the Water & Power Development Authority of West Pakistan on Phase No. 1 Mari Thermal Power Project 2 66,000-kw units", May 1965).

ANNEX 5

THE PRICE OF THERMAL FUEL

THE PRICE OF THERMAL FUEL

Table of Contents

THE PRICE OF THERMAL FUEL

It was suggested in Annex 4 that it was possible to foresee a reasonable balance between the domestic demand for energy in West Pakistan and the supply of energy over the next 10-15 years, on the assumption that fuel imports would remain at about three percent of total imports. Towards the end of the Perspective Plan period, however, imports might have to rise above this level if no new fuel reserves were to be discovered in the meantime. Natural gas would be the most rapidly growing domestic mineral source of energy.

In the overall energy projections at the end of Annex 4 it was assumed that the hydroelectric projects recommended in this report would be undertaken and that some natural gas would be used for thermal generation of electricity. However natural gas is also the main foreseeable alternative to hydro plant as a source of electric energy in West Pakistan. For purposes of assessing the value of the Province's natural gas reserves (and subsequently the value of the hydroelectric projects) it is useful to consider the implications of a conservationist decision to reserve all the natural gas deposits for non-electrical uses. The reserve estimates given in Annex 4 showed a total thermal value of gas reserves of about 10,000 trillion Btu. However, there is doubt about the extent to which the relatively small fields -- Uch, Khairpur and Zin -- could in fact be brought into use economically. Moreover, as pointed out in Annex 4, the usefulness of the relatively large reserves at Dhulian is limited by the low daily off-take that is technically possible; the availability from Dhulian was netted out of the non-electrical demand projections shown in Table 9 of Annex 4. Thus the reserves appropriate for comparison with estimated requirements are those in the remaining five fields, or about 7,300 trillion Btu. Total withdrawals from these fields for non-electrical purposes, as projected in Table 9 of Annex 4, would account for about 3,100 trillion Btu by 1985; this table also showed consumption running at the level of about 275 trillion Btu per annum by that year. Therefore, if a strictly conservationist view were taken, and all the natural gas available to West Pakistan were reserved for non-power uses the reserves as currently estimated would be sufficient to sustain consumption to about the year 2000, provided that no new commitments were made after about 1985. 1/ If we take a slightly more optimistic view of reserves and assume, say, that the Sui field is somewhat larger than now believed, so that total reserves are of the order of 9,500 trillion Btu, then this would suffice to prolong consumption at the 1985 level for a further eight years to about 2008, provided that all gas was reserved for non-electrical use.

What is the implication of these trends in non-electrical demand for gas for the power development program? Should the natural gas reserves

1/ Assuming approximately a 15-year commitment, comparable with a 15-year life for many of the relevant gas-consuming types of plant.

really be conserved for non-electrical use and, if so, to what extent? How far would the answer to this question be changed by a change in the estimate of natural gas reserves? What will be the cost to Pakistan of exceeding the 'acceptable' level of three percent of total foreign exchange expenditure for fuel imports? Some better perspective on the alternatives available may be had by expressing the relationship between supply and demand in terms of economic price trends.

Current Financial Price of Natural Gas

The price actually charged to the consumer for natural gas has fallen substantially over the years as a result of increasing demand bringing the lower levels of the slab-pricing structure (see, e.g., Appendix Tables 1 and 2) into operation and as a result of across-the-board price reductions. It now compares very favorably with the price of imported fuel oil in locations reached by the gas pipeline, as indicated in the following table.

Table 1

Delivered Prices of Fuel Oil and Natural Gas a/
(PRs per million Btu)

Location	Fuel Oil	Natural Gas			
		Average		Price Structure for Major Consumers	
	Current 1964/65 b/	General	KESC & WAPDA	Max.	Min.
Karachi	2.87	2.17 c/	1.70	2.30	1.28
Sukkur (Mari)	3.44	2.41 d/	2.00	n.a.	n.a.
Multan	3.80	2.29	2.30	2.87	2.10
Lyallpur e/	3.93	2.29	-	2.87	2.10

a/ A straight comparison between the prices of fuel oil and natural gas in terms of rupees per million Btu to some extent exaggerates the price for gas, which has been found to be thermally more efficient for many purposes. KESC has established that, for its purpose, gas is overall four percent more efficient than fuel oil, while for many other purposes the difference is even greater; experiments have shown, for instance, that Sui gas is 36 percent more efficient for glassmaking.

b/ Current prices, including tax 1964/65, as given in A.U. Loan "The Last Ten Years of Natural Gas in Pakistan" (November 1965).

c/ 1964.

d/ 1963.

e/ Lyallpur was not in fact connected to the gas supply system until 1965; the gas-fired generators at Lyallpur are only coming into operation during 1967 but the price structure for gas supply was agreed between WAPDA and SNGPL some time ago.

The table indicates that the slab-pricing system under which KESC receives gas results in an average price of about PRs 1.70 (US 37 cents) per million Btu (compared to about PRs 2.00 (US 42 cents) per million Btu in 1960/61), while the agreement under which WAPDA receives gas for its Multan (and in future Lyallpur) plants results in an average price of about PRs 2.30 (US 48 cents) per million Btu. Nevertheless the saving to WAPDA from using gas is considerably greater than the comparable saving to KESC because of the high costs of rail transportation of imported fuel oil. The price structures established for major consumers equally result in much greater savings from the use of gas in the North than in the South.

The Price of Gas for Planning Purposes

It would be possible to plan for the development of the power sector on the basis of the current financial fuel prices discussed in the preceding paragraph. However, these prices do not provide a very solid basis for planning ten or twenty years into the future. In the first place they may change at any time -- as they have been changing over the years since the gas fields were first developed. In the second place, and much more important, these financial prices cannot be related in any meaningful way to the broader questions of fuels policy raised at the beginning of this chapter. What is required for purposes of long-term planning is some procedure which recognizes that mineral fuel reserves are an exhaustible resource and indicates a sensible way of rationing out the known reserves over the years. The key problem is to define what West Pakistan loses when a cubic foot of gas is burned up -- or, in other words, the cost to the economy in terms of opportunities foregone as a result of burning this cubic foot of gas.

It was with a view to approaching a tentative solution of this problem that considerable attention was devoted in Annex 4 to trying to establish prospective demand for natural gas for non-electrical purposes and the amount of time that the natural gas deposits would last if reserved entirely for such purposes. For the gas fields can reasonably be conceived as being made up of a number of successive layers which will be consumed one by one over the years until the reserves are exhausted. The projections in Annex 4 suggested that, if the reserves of all the main gas fields as currently estimated were reserved for non-electrical use, they would last till about the year 2000, when the last layer of 275 trillion Btu would finally be used. The result of using gas in the interim for power generation will therefore be to eat into this bottom layer and force West Pakistan to import some other fuel in 2000 to the same order of magnitude of thermal value as the gas consumed. If interim consumption of gas for power generation aggregates less than 275 trillion Btu then only the layer which had been reserved for 2000 will be affected; but once it exceeds this amount it will begin to eat into the layer that had been reserved for 1999. If it is large enough it may begin to affect the layers reserved for even earlier years. Thus the effect of using gas now for power generation is to burden future generations with the need to import an equivalent amount of fuel. The value of the gas used at any

time can reasonably be regarded as the present worth (at that time) of the cost of importing the equivalent amount of fuel in the first year in which such imports would become necessary as a replacement to natural gas supplies.

The problem therefore is one of defining the real economic cost, as far as it can now be foreseen, of fuel imports towards the end of the century. The main alternative to natural gas as a fuel is likely to be in the future, as it is now, fuel oil, and attention has therefore to be given to the likely international price of fuel oil in the distant future. However there is another dimension to the foreseeable economic cost of large-scale fuel imports in the future -- the burden that it will place on Pakistan's foreign exchange budget -- and so special consideration must be given to the foreign exchange component of the cost of fuel oil imported and delivered to energy consumers in West Pakistan.

The Economic Price of Fuel Oil

Current fuel oil prices were cited in Table 1 above, but these prices include substantial tax and foreign exchange components, so that they have to be adjusted before they can be taken as indicating real economic costs. In June 1964 Burmah-Shell quoted a price to Stone & Webster for bulk supplies of fuel oil c.i.f. Karachi, excluding taxes. This price (about PRs 57 or US $12 per ton of heavy fuel oil) may be taken as 100 percent foreign exchange. The net-of-tax price at which the Pakistan Refinery supplied fuel oil at refinery gate in 1965/66 was almost the same -- about PRs 56 per ton. The foreign exchange component of this price is hard to identify because it was incurred for purchase of crude oil from which many products were derived, so that any distribution of the foreign exchange burden among the different products would be somewhat arbitrary. The net current foreign exchange costs incurred by the refinery for import of oil for processing (i.e., foreign exchange cost of imported crude plus additives less foreign exchange earnings from products exported) was about 70 percent of the total earnings of the refinery from inland sales of petroleum products. On this basis it is possible to say that the foreign exchange portion of the fuel oil price in the short term is about 70 percent or PRs 40 (US $8.40) per ton. However, from a longer-term point of view the foreign exchange cost of domestically refined crude oil is obviously much greater chiefly because of the large foreign exchange component of the capital costs of refineries. Therefore, if it is assumed that substantial future needs of fuel oil could be refined domestically from imported crude 1/ the long-term foreign exchange costs of such supplies might be set at about 85 percent.

1/ This assumes that demand for the lighter and medium ends of the crude in West Pakistan would have expanded sufficiently to make it worthwhile to refine the fuel oil in Pakistan. The current position is that demand is peaked in the middle distillates so that some of the heavier products are surplus to domestic requirements and have to be exported at prices that are low compared to world market prices.

The ex-refinery net-of-tax price of PRs 56 per ton of fuel oil was based on a current price of crude of $11.95 per ton c.i.f. Karachi, exclusive of duties, taxes and wharfage, etc. The long-term trend of the price of the crude is quite uncertain; it could be subject to violent fluctuations due to unforeseeable political developments. Over the last ten years c.i.f. crude oil prices have shown a substantial downward trend as a result of both falling freight prices and falling f.o.b. crude prices. Part of this sharp fall results from the disturbance in the price trend occasioned by the Suez Crisis of 1956, but even since 1959 oil freight costs on a worldwide weighted average basis have fallen at a rate of about six percent per annum while f.o.b. prices of oil have fallen at a rate of about three percent per annum according to estimates by the Bank's commodities specialists. These downward trends are attributable to a number of forces, including restrictive policies on the use and import of petroleum in developed countries, increasing competition with the major producers from independents in the Middle East, Africa and Venezuela, and the expanding volume of Soviet oil exports to the non-communist world. The Bank's commodities specialists anticipate no reversal of the trend in the near future since these policies are likely to continue, the proven oil reserves of the non-communist world are sufficient to sustain consumption at the 1965 rate for more than 30 years, ultimately recoverable supplies (with account taken of probable and possible reserves and technological advances) could be seven times greater, and there have been substantial discoveries of gas in Western Europe recently which could significantly affect demand for oil there. In fact the commodities specialists feel that the prospect, at least for the short term, is a further decline in prices of crude oil at a rate somewhat less than that experienced in the past. If an allowance is made for the greater uncertainties of the longer period with which we are concerned, the best oil price figure for long-term planning purposes may be the current one. Nevertheless, in using this, we should bear in mind that political upheavals could increase it substantially at least for short periods.

If we adopt the rail freight prices provided to the power consultant by the Pakistan Western Railway and assume that they have no foreign exchange component then we can derive the following set of long-term prices for fuel oil at different foreign exchange rates (Table 2). The first column shows net-of-tax prices for fuel oil in PRs per ton at the four different locations. The middle two columns show the same data in terms of PRs and US cents per million Btu. All these columns are based on converting foreign exchange components at the current foreign exchange rate. The last two columns present the same prices, again in both PRs and US cents, with the foreign exchange component doubled. It should be noted that the US currency is used here not for indicating international prices but as a unit of account; therefore the rupee prices convert into dollars in both sets of columns at the current official exchange rate but in the second set of columns all foreign exchange components (whether expressed in US dollars or in PRs) are simply doubled.

Table 2

Prices of Fuel Oil for Planning Purposes (Excluding Taxes)

	Current Exchange Rate ($1.00 = PRs 4.76)			Shadow Exchange Rate ($1.00 = PRs 9.52)	
	PRs per ton a/	per million Btu		per million Btu	
		PRs	US cents	PRs	US cents
Karachi	70.0 b/	1.69	36	2.84	60
Mari	83.0	2.00	42	3.16	66
Multan	113.0	2.72	57	3.88	81
Lyallpur	116.0	2.80	59	3.96	83

a/ Assumes 18,530 btu's per lb. or 41.5 million Btu's/long ton.
b/ i.e. the base price of PRs 56/ton plus PRs 14/ton delivery charge, in Karachi, 85 percent of the PRs 56/ton is assumed to be foreign exchange cost (see discussion above).

The rail freight rates assumed in these calculations, being current financial prices, rather than economic prices (i.e. excluding duties, taxes, etc.), are probably on the high side for use in the calculations at current foreign exchange rates but on the low side for use in the calculations at a higher foreign exchange rate (i.e. its scarcity price).

Economic Price of Natural Gas

Before the prices of fuel oil given in Table 2 become appropriate for use in our procedure for determining the economic price of natural gas a decision has to be made as to the exchange rate at which the foreign exchange components should be converted. Discussion in the Economic Annex to this report suggests that the present scarcity value of foreign exchange in West Pakistan should be considered to be about twice the current official exchange rate of PRs 4.76 to the US dollar. According to the evidence presented there the current supply of foreign exchange and the demand for imported goods in the economy as a whole are such that they can only be brought into balance by effective prices for imported goods which are twice what they would be if foreign exchange were freely available at the current exchange rate and expenditure of foreign exchange were not constrained by Government controls and taxes. The evidence is not complete, relating only to the import side of the balance of payments, but it is indicative. For estimating the future effective foreign exchange rate it is impossible to go even as far as this. What we require is a detailed analysis of the future demand and supply for foreign exchange to give some indication of the foreign exchange stringency that is likely to exist at different times through the Perspective Plan period and subsequently. What we have is no more than the general judgment that the Perspective Plan certainly implies no easing in the foreign exchange situation and probably indicates some increase in its scarcity.

Within these constraints the best course that seems feasible is to follow through with the assumption that was made in the determination of the current scarcity value of foreign exchange -- namely, that the current allocation of available foreign exchange is reasonably optimal. Annex 4 showed that this allocation involved devoting about three percent of available foreign exchange to purchase of fuel imports. It was further assumed in Annex 4 that about three percent of the annual supply of foreign exchange could continue to be used for fuel imports without upsetting the optimality of the general allocation of foreign exchange among different sectors. Projections based on this assumption (see Annex 4, Table 11) suggested that this would provide barely enough foreign exchange to meet those of West Pakistan's fuel requirements which could not be supplied from domestic sources. This was partial confirmation, from the point of view of the energy sector, of the general statement that the Perspective Plan implies no alleviation of the foreign exchange problem. Nevertheless, within the framework set by these assumptions, it would be possible to import fuel up to the limit of three percent of foreign exchange expenditure at prices calculated on the basis of the current scarcity value of foreign exchange -- about US cents 66 per million Btu, for instance, for fuel delivered to Mari, according to Table 2.

Fuel imports required to meet needs that had previously been met by natural gas will clearly be additional to this three percent of foreign exchange expenditure, for the projection in Table 11 of Annex 4 showed very substantial amounts of total fuel requirements being met by natural gas in later years besides those met by imports within the fixed limit. Clearly then the additional fuel imports occasioned by exhaustion of the natural gas reserves of the Province would exacerbate the general shortage of foreign exchange. The effect of the need for additional fuel imports can be assessed, for purposes of illustration, on the assumption of unity price elasticity of demand for import goods. Suppose that the requirement for imported fuel increases 33 percent from 3 percent of total foreign imports to 4 percent. Then imports demanded at the old foreign exchange price (of double the current rate) would be one percent more than the total foreign exchange available; the scarcity value of foreign exchange would rise one percent and marginal imports in all sectors would be eliminated.

Thus the result of the greatly increased need for fuel imports would be not only to increase the amount of foreign exchange that must be allocated to cover these imports but, pari passu, to cause an upward shift in the effective exchange rate -- indicating the effect of the increased foreign exchange stringency on all foreign exchange using sectors. This would be a real cost to these sectors resulting from, and therefore attributable to, the import needs of the energy sector. An indication of the total cost of the additional imports required can be obtained, in the absence of better evidence, by assuming again unity price elasticity of demand for imports. The cost to the other sectors in terms of increased PR prices of imports would be approximately equal to the value of the additional amount of foreign exchange that had to be allocated to cover the increase in fuel imports.

Thus the foreign exchange rate which would appear reasonable for purposes of this analysis, as a means of indicating the burden added by not conserving natural gas reserves, would be twice the current scarcity rate, or, in other words, twice the rate on fuel imports within the three percent level. Such a rate, calculated on the basis of many simplifying assumptions, can clearly only be indicative but it seems to encompass reasonably adequately the double penalty that should be attached to additional fuel imports: the direct foreign expenditure, valued at the current scarcity rate of exchange, and in addition the effect on the exchange rate for the whole economy -- here valued at an amount equal to the additional direct foreign exchange expenditure involved.

Valuation of the foreign exchange component of fuel imports required to substitute for natural gas at twice the current scarcity price (or four times the current official exchange rate) would mean that fuel delivered to Mari/Sui at the time of exhaustion of gas reserves would cost the Pakistan economy PRs 5.42 or US $1.14 per million Btu. Therefore if a million Btu of gas that would have been available in 2000 is used, say in 1966, for generation of power, this would mean that Pakistan faces an additional cost burden of $1.14 in 2000. The present worth of this cost, on an eight percent discount rate, is US cents 8.1. The real sacrifice to the Pakistan economy involved in using this million Btu of gas in 1966 is therefore PRs 0.39 or US cents 8.1. Similar calculations can be made for other years. As the cumulative consumption of gas for electricity production increases beyond the projected level of non-electrical consumption in 2000, so layers of gas that had been reserved for earlier years will be affected and the year in which the corresponding fuel import will become necessary will be brought forward. A series of calculations can thus be made, one for each year, which take account of this cumulative reduction in the amount of gas available for non-electrical purposes and which indicate the real economic value of the gas in each year.

Calculations of this sort cannot however be made without some assumption as to the amount of gas that is required for generation of electricity, for the larger the draft on the gas reserves, the more rapidly will the gas reserves be exhausted and the earlier are the years when conversion to imported fuel oil would become necessary. Many of the programs to be considered in the course of the Study do not in fact differ sufficiently from each other to make separate calculations worthwhile. However, the presence or absence in a program of Tarbela, with its annual output of twelve to thirteen billion kwh obviously makes a tremendous difference. Therefore, separate calculations have been made, on the above lines, as to the economic value of gas in different years, first on the assumption that Tarbela will come on line in 1975 and second on the assumption that it will be completed in 1985.

The economic value of gas which results from this approach depends critically on the assumption made with respect to reserves as well as on the assumptions about future price trends for fuel and for foreign exchange. The most uncertain of these is the reserves. It is shown in Annex 4 how estimates of gas reserves have recently been revised sharply downward. On the assumption that all the known fields with reserves of

good quality gas would be brought into use by appropriate siting of plants or by linking them with the existing Sui pipeline so that they would be available to meet projected non-electrical demands or requirements for power generation, we have adopted a total reserve figure of about 7,300 trillion Btu (i.e. Sui + Khandkhot + Mazarani + Mari + Sari Sing). However, to indicate the sensitivity of the approach to changes in the estimates of reserves, the calculations have also been run for the hypothetical larger reserves (9,500 trillion Btu).

Table 3 and Figure 1 show the results of these calculations. The consumption of gas for production of electric power would be small in the early part of the period relative to the size of the reserves and the year of exhaustion of the gas reserves would be some distance into the future, so that the economic value of the gas at well head is low. By 1975 it would be nearly 20 cents per million Btu if gas reserves were as presently estimated (and about 10 cents per million Btu if gas reserves turned out to be at the higher level). In 1978 the economic price trends for the case with Tarbela in 1975 and that with Tarbela in 1985 would start to diverge. If Tarbela is completed in 1975/76 then the economic value of gas in 1980 will be, on present knowledge, somewhat below 30 cents per million Btu.

If Tarbela is not constructed by then it will be a little above 30 cents per million Btu. By 1985 the economic value of gas will be about 45 cents if Tarbela is available from 1975/76, while it will be more than 50 cents if completion of Tarbela is delayed to 1985. If the gas reserves are as much as 2,200 trillion Btu larger than presently estimated then the economic values of gas in the different years will be very much less -- little more than half the figures given above -- so that, for instance, by 1985 the value of gas with Tarbela in 1975 will have risen to only about 25 cents per million Btu and with Tarbela in 1985 it will have risen to about 29 cents per million Btu.

These economic price trends appear reasonable, but they may be on the low side, unless substantial additional discoveries of indigenous thermal fuel are made. It is right that they should be relatively low currently, for the known gas reserves are large compared to existing levels of use. However, the analysis does rest on the assumption that general foreign exchange shortage will not become substantially more acute than it is now until the time that natural gas reserves are exhausted. This is a simplifying assumption, and the more likely path, for the energy sector as for the general economy, is a gradually increasing foreign exchange stringency over the Perspective Plan period. In practice, of course, the price of imported fuel, even when valued at the prevailing scarcity exchange rate, should never reach the levels projected here; but the object of this exercise is not to show actual future scarcity prices of imported fuel but rather hypothetical prices that reflect in the price of fuel the effects on the exchange rate and hence on the overall economy of substantially increased fuel imports.

Table 3

Economic Prices of Natural Gas on Different

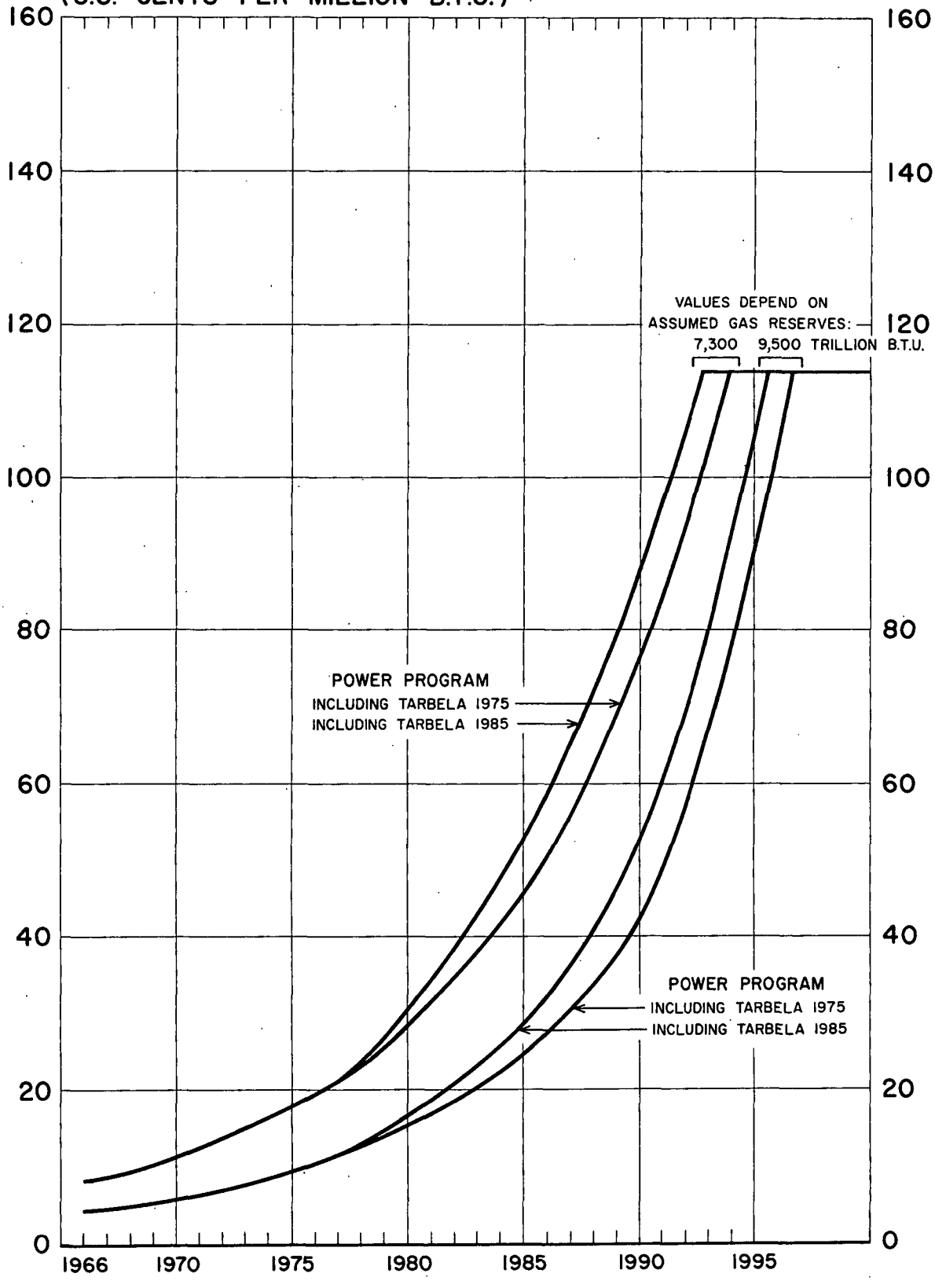
Assumptions with Regard to Completion

Date of Tarbela and Size of Gas Reserves
(US cents per million Btu)

	Total Gas Reserves: 7,300 trillion Btu		Total Gas Reserves: 9,500 trillion Btu	
	Tarbela, 1975	Tarbela, 1985	Tarbela, 1975	Tarbela, 1985
1966	8.1	8.1	4.3	4.3
1967	8.8	8.8	4.7	4.7
1968	9.6	9.6	5.1	5.1
1969	10.5	10.5	5.5	5.5
1970	11.3	11.3	5.9	5.9
1971	12.2	12.2	6.4	6.4
1972	13.2	13.2	7.0	7.0
1973	14.3	14.3	7.5	7.5
1974	16.6	16.6	8.8	8.8
1975	18.0	18.0	9.6	9.6
1976	19.4	19.4	10.5	10.5
1977	21.0	21.0	11.3	11.3
1978	22.7	24.5	12.2	13.2
1979	24.5	26.4	13.2	14.3
1980	28.5	30.8	15.4	16.6
1981	30.8	33.3	16.6	18.0
1982	33.3	38.8	18.0	21.0
1983	35.9	42.0	19.4	22.7
1984	38.8	48.9	21.0	26.4
1985	45.3	52.8	24.5	28.5
1986	48.9	61.6	26.4	33.3
1987	52.8	66.5	28.5	35.9
1988	61.6	77.6	33.3	42.0
1989	66.5	83.8	35.9	45.3
1990	77.6	97.7	42.0	52.8
1991	90.5	114.0	48.9	61.6
1992	105.6		57.0	71.8
1993	114.0		66.5	83.8
1994			77.6	97.7
1995			90.5	114.0
1996			114.0	

PROJECTION OF THE ECONOMIC VALUE OF NATURAL GAS AT WELL HEAD

(U.S. CENTS PER MILLION B.T.U.)



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Using Gas to Earn Foreign Exchange

Another reason why the figures resulting from this analysis should be considered conservatively low estimates of the value of natural gas reserves in the various years, is that there are other uses for gas, not taken into account in the analysis, which could bring forward the critical date when the reserves would be exhausted. The projections of non-electrical gas requirements used here, although on the optimistic side of the gas transmission companies' sales projections, are apparently more conservative than those used by the Planning Commission. They are also conservative in that they were built up largely in terms of requirements to meet domestic needs; yet there may well be significant possibilities of using gas to produce export products and thus earn foreign exchange. This applies particularly to fertilizer. Some illustrative calculations have been made along these lines regarding the production of nitrogenous fertilizer at Mari/Sui for sale in the neighboring regions of India. Annual demand for fertilizer in the Indian Punjab has been projected to rise, in terms of nitrogen, to about 155,000 tons by 1970. There is at present only one nitrogenous fertilizer factory in Northern India and it has insufficient capacity to meet this demand; but considerable attention is being given to means of increasing the supply of fertilizer. One way of meeting the need that has been discussed is to import ammonia and convert it into urea or another nitrogenous fertilizer locally. 150,000 tons of nitrogen are the equivalent of about 200,000 tons of ammonia. It has been suggested that the cheapest source of ammonia for India would be the Persian Gulf, since an ammonia plant based on natural gas is the cheapest in capital cost and since vast quantities of natural gas are presently being flared in the Middle East oil-producing states. Natural gas for such a plant would probably be available in Kuwait at about US 5 cents per million Btu. But what if an identical plant were established at Mari? Ammonia might then be provided to the Indian Punjab, say Ludhiana, with the following savings in transport cost:

Table 4

Estimated Savings from Supplying Ludhiana with Ammonia from Mari as Compared with Kuwait
(US dollars/per long ton)

Sea Transport, Kuwait-Bombay a/		3
Storage and terminal charges		6
Rail charges b/		
Bombay-Ludhiana (1,700 km)	IRs 171	
Less: Mari-Ludhiana (700 km)	IRs 87	
	IRs 84	11
		20

a/ A low estimate, based on the figure of $6.1/long ton of ammonia for Kuwait-Madras (2,600 nautical miles).

b/ Generous estimates have been made of the route mileage Mari-Ludhiana. The assessment of rail charges is based on the Indian tariff structure which tends to be unduly tapered.

US$ 20 per long ton of ammonia is probably a conservative estimate of the savings available. However, if we assume that such savings were divided equally between India and Pakistan, then Pakistan would be earning $10 per ton of ammonia supplied to India, over and above the normal profit level of an ammonia plant, thanks to her location and her gas reserves. In other words, if Mari gas were used for this purpose, it would be earning for Pakistan, in addition to the regular profits of an ammonia plant, about US cents 32 per million Btu. 1/ A plant to produce 200,000 tons of ammonia per year (approximately 600 tons per day) would need about 10 billion cubic feet of Mari gas per year, excluding power requirements, or 0.16 trillion cubic feet over a 15-year period. This example illustrates what is possible with a relatively small quantity of gas. The potential for absorption of Pakistani ammonia in neighboring areas is obviously a good deal larger than has been indicated in this illustration. High returns are possible when it can be exported -- e.g. about 64 cents per million Btu of gas at the current shadow foreign exchange rate used here (i.e. $1.00 = PRs 9.52). To the extent that substantial quantities of gas could be used, say in the late 1970's for purposes of earning foreign exchange it would considerably increase the economic value of West Pakistan's natural gas reserves.

Financial Price of Gas

The range of prices indicated in Figure 1 refers to the economic value of Sui-Mari gas at wellhead. The current financial price of Sui gas delivered to the purification plant (which is close to well head) is actually about US cents 10 per million Btu. SGTC pays a pre-purification price of about 10.8 cents per million Btu (PRs 0.50 per MMcf) for its gas, while SNGPL pays about 9.6 cents per million Btu (PRs 0.44 per MMcf) for gas to be purified and dispatched down its line. These are prices which are set by negotiation and they relate more to factors such as the operating costs of the company exploiting the field (Pakistan Petroleum Ltd.), its sunk costs in facilities and in exploration here and elsewhere and the extent of the Government's desire at any time to encourage future exploration. Thus they are conceptually quite different from the 'economic values' shown in Table 3. The 'economic value' calculation has little to say about the financial price that should be paid for the gas except that a rising

1/ About 37 million Btu of Kuwait gas at US cents 5/million Btu would be needed as feedstock and reformer fuel to produce 1 ton of ammonia. Assuming that Mari gas to the same thermal value would be required, then the earnings attributable to the 37 million Btu of Mari gas would be US$ 10 + (.05 x 37) = $11.85 or US cents 32/million Btu.

economic value would imply the need for a financial price that would be high enough to encourage careful use of the gas and increased exploration for future reserves. It is the economic value that is more relevant for long-term planning purposes.

Price of Gas Delivered to Market

The 'economic price' figures in Table 3 refer to the value of Pakistan's natural gas reserves in different years at well head. Since the various gas pipelines in the Province are mostly working close to capacity already, increases in supply will require expansion of the gas-transmission facilities, and so the economic price for gas delivered to the market -- e.g. to Karachi and Lyallpur -- should be somewhat higher. However, the power programs discussed in the Bank Group's report vary greatly in the amount of gas required for power generation in the Northern Grid and in Karachi; some require considerable expansion of gas pipeline capacity while others require almost none at all. Therefore use of an average cost per million Btu for transmission of gas from Sui to market would be rather misleading. Since the comparison between gas transmission and electricity transmission is quite important in the overall study it seemed best from the economic point of view to treat gas transmission explicitly in terms of investment costs for different amounts of pipeline capacity. This is the procedure adopted by the Bank Group.

Power Consultant's Gas Price

Stone & Webster worked largely in terms of current financial prices for Sui gas, similar to those given in Table 1 -- about 35 cents per million Btu (PRs 1.67) for gas delivered to KESC and about 47 cents per million Btu (PRs 2.25) for gas delivered to WAPDA in Lahore or Multan. These are approximate averages of the prices actually paid. As pointed out early in this annex, both prices are intimately dependent on the individual slab-pricing structures agreed between the utilities and the gas transmission and distribution companies. Reduced requirements for gas may substantially increase the average price to the utilities, while increased requirements would bring down the average price considerably. Appendix Tables I and II give some details of the current slab-price structures of the historical picture for KESC and the future situation for WAPDA Northern Grid plants as projected some three years ago when the agreement between WAPDA and SNGPL was made.

At the time Stone & Webster were preparing their power program, no agreement had been reached as to the price that might be charged for Mari gas. They, therefore, had to make some arbitrary choice of price and they selected 12 cents (PRs 0.57) per million Btu for Mari gas delivered to a power plant in the neighborhood of the field. Of this price, about 2.4 cents were intended to cover the costs of gathering and short delivery. This price is, therefore, approximately the same as the pre-purification price presently charged for Sui gas.

The economic analyses made above also use a single price per million Btu to indicate the value on the field of both Mari and Sui gas, but they suggest that the price appropriate for long-term planning purposes is somewhat higher than that used by the power consultant for Mari gas. The right hand columns of Table 3 indicate the economic value of gas calculated on the basis of approximately the same estimate of gas reserves as was available at the time Stone & Webster were carrying out their studies (i.e. Mari with 5 trillion cu. ft. instead of the revised estimate 1.8 trillion cu. ft.). On that assumption with regard to reserves the price used by the power consultant appears appropriate through the major part of the planning period; but it is on the high side for the early part of the period and rather low for the later part. The more recent estimate of the reserves suggests that the scarcity value of the gas should be considered significantly higher throughout the period.

Appendix Table I

Sui Gas - Price to KESC

(1) Price Structure

	MMcf per Month	PRs per Mcf
First	10	2.25
Next	90	2.20
	100	2.15
	100	1.95
	100	1.70
All Over	400	1.25
Average for first	400	2.00

(2) Actual Prices Paid
(PRs per Mcf)

Calendar Years	PPL's Price[a] to SGTC	SGTC's Average Price to KGC	KGC's Average Sales Price	KGC's Average Price to KESC
1960	0.50	1.65	2.26	1.97
1961	0.50	1.58	2.23	1.99
1962	0.50	1.49	2.18	1.91
1963	0.50	1.45	2.18	1.85
1964	0.50	1.31	2.12	1.72
1965[b]	0.50	1.28	n.a.	1.66

a/ PPL stands for Pakistan Petroleum Limited, which operates the Sui gas field.
b/ Fiscal 1965.

Appendix Table II

Sui Gas - Price to WAPDA for Northern Grid

(1) Price Structure

Fiscal Years	At Multan Fixed Annual Charges ('000 PRs)	Commodity Charges (PRs/Mcf)	At Lyallpur Fixed Annual Charges ('000 PRs)	Commodity Charges (PRs/Mcf)
1965	14,436	1.23	0	1.23
1966	14,436	1.23	4,608	1.23
1967	14,436	1.23	4,608	1.23
1968	14,436	1.23	4,608	1.23
1969	4,560	1.23	3,324	1.23
1970	4,560	1.23	3,324	1.23
1971	4,560	1.23	3,324	1.23
1972	4,560	1.23	3,324	1.23
1973	4,560	1.23	3,324	1.23
1974	4,560	1.23	3,324	1.23
1975	4,560	1.23	3,324	1.23

(2) Actual Prices

The structure of prices agreed between WAPDA and SNGPL is such that the average price declines rapidly in any one year as consumption increases. The actual price will depend directly, therefore, on the rate at which power load grows and the amount of hydro energy available from existing hydro plants and Mangla. Projections were made three years ago suggesting that the average price to WAPDA for consumption of gas at Lyallpur and Multan would be as follows over the next decade:

Fiscal Years	Average Daily Consumption (MMcf)	Total Annual Consumption (MMcf)	Total Paid to SNGPL (PRs million)	Average Price (PRs/Mcf)
1966	36.69	13,396	31.17	2.33
1967	47.18	17,228	37.12	2.15
1968	58.84	21,462	45.89	2.14
1969	58.01	21,170	45.51	2.15
1970	31.90	11,644	22.43	1.93
1971	22.94	8,359	18.34	2.19
1972	20.07	7,337	17.03	2.32
1973	23.07	8,432	18.40	2.18
1974	9.98	3,650	12.44	3.41
1975	5.26	1,935	4.39	2.27

ANNEX 6

HYDROELECTRIC PROJECTS AND RESERVOIR OPERATION

HYDROELECTRIC PROJECTS AND RESERVOIR OPERATION

Table of Contents

Table of Contents (continued)

HYDROELECTRIC PROJECTS AND RESERVOIR OPERATION

The central purpose of the studies discussed in this and the following annexes was to analyze the development of West Pakistan's hydroelectric resources over the next twenty years and to consider how recommended hydroelectric projects might best be assimilated into the province's power system. It was pointed out in Annex 4 that West Pakistan's total hydroelectric potential had been conservatively estimated at about ten million kw, of which less than 250,000 kw had so far been developed. This Annex sets out to note briefly the hydroelectric potential of the rivers of West Pakistan, focusing attention on some of the characteristics of the rivers which are important from the power point of view. It attempts to relate the hydroelectric projects which have been studied in detail to the general hydroelectric potential of the Province. And it introduces the main questions regarding hydroelectric development which are considered in the following annexes as well as the procedures adopted for estimating the power potential of alternative hydroelectric developments and alternative patterns of reservoir operation.

The Major Rivers of West Pakistan

The Indus main stem and its principal tributaries, the Kabul, Jhelum, Chenab, Ravi, Beas and Sutlej form a link between two great natural reservoirs, the snow and glaciers in the mountains and the groundwater contained by the alluvium in the Indus plains in West Pakistan and India. The total rim-station discharge into the plains averages about 175 MAF a year, a little more than one-third of it in the Indus itself. When the Indus Waters Treaty of 1960 is fully implemented there will be four main rivers whose flows will be available to Pakistan -- the Indus, Kabul, Jhelum and Chenab, which have a combined average annual discharge of about 142 MAF, nearly one-half in the Indus itself and the remainder roughly equally divided between the other three rivers.

The Indus River rises in Tibet, in a catchment which contains some of the largest glaciers in the world outside the Polar regions. Snow and ice melting in this glacial area of about 14,000 square miles probably supply about half the total flow of the Indus in the summer season. The importance of this source helps to account for two significant characteristics of the flows in the Indus -- their relatively high seasonal concentration and their relatively small fluctuation from year to year. Of the total mean flow of the Indus at Attock (below the confluence of the Kabul) about 72 percent (or 67 MAF) occurs in the four months June to September. Annual mean flow on the Indus at Attock is about 93 MAF and the total range of recorded flows is from about 75 percent of this to 118 percent. The difference between mean annual yield and the yield which would be exceeded in three years out of four is only about 6 percent. The Indus River falls rapidly between the place where it crosses the cease-fire line

from Indian-held Kashmir and Chasma, where it debouches into the plains -- nearly 8000 feet in 600 miles. Three-quarters of this drop is concentrated in the so-called Indus Gorge, about 300 miles long, between Skardu and a point some 30 miles downstream of Tarbela Dam site. In the 900 miles over which the river flows between Chasma and the Arabian Sea, on the other hand,the river drops only about 500 feet in total.

The Jhelum is a very different type of river from the Indus: mean annual flows are only about one-third of those in the Indus and they are much more variable from year to year. The river rises in Indian-held Kashmir at a much lower elevation than the source of the Indus and it falls much less rapidly than the Indus after entering Pakistani territory. Snowmelt accounts for some of the flows in the Jhelum, but it is much more dependent than the Indus on variable monsoon runoff. Partly as a result, flows in the Jhelum are less concentrated within a few months -- only about 12 MAF or 53 percent of the total mean flow occurring in the four peak months -- but they are more variable from year to year. Annual recorded flows at Mangla range between 65 percent and 135 percent of the mean flow of 23 MAF. The difference between mean annual yield and the yield which would be exceeded in three years out of four is over 12 percent or more than double the comparable difference on the Indus. The Jhelum falls about 1000 feet in 100 miles before it is joined by the Kunhar River. Between the confluence of the Kunhar and Mangla it drops a further 1000 feet in somewhat more than 100 miles to an elevation of about 1000 feet above mean sea level at Mangla.

The Chenab and the Kabul are rivers of less importance from the point of view of hydroelectric development in West Pakistan over the next twenty years -- the Chenab because of its lack of suitable sites and the Kabul because it is already partly developed 1/ and any future development on the basis of Kabul water in the near future will probably be on the Indus main stem downstream of the confluence. The Chenab, with mean flows of about 26 MAF, is a river of somewhat similar flow characteristics to the Jhelum. Low years on the Chenab are often also low years on the Jhelum. It falls less than 500 feet in about 400 miles between the Marala Headworks near the Indian border and the confluence with the Panjnad. Chenab flows in the summer are somewhat more reliable than those on the Jhelum; the river is a very important source of irrigation supplies and since it

1/ The so called Pak-Afghan site upstream of Warsak at the border between Pakistan and Afghanistan could turn out to be very valuable for storage and for power. WAPDA believes that a large reservoir could be built in the area; siltation would be significantly less relative to the size of the reservoir than at most of the other sites discussed in this report. However, no specific dam site has been identified and there is virtually no information available on the potential project.

commands many of the same areas as the Jhelum, regulation of the Jhelum has to be planned taking into account Chenab flows. The Kabul River, which rises in Afghanistan and is being partly developed there for hydroelectric and irrigation purposes, has more variable flows than any of the other three rivers. Mean flows on the Kabul above Warsak are estimated at about 17 MAF per annum and Surface Water Circle records indicate that over the period of record since 1921/22 flows have ranged between about 65 percent and more than 160 percent of mean. Mean flows on the Kabul at the point where it joins the Indus are estimated at about 27 MAF. In the relatively short distance of about 100 miles between the border with Afghanistan and the confluence with the Indus the Kabul drops some 400 feet.

Besides the distinctions between the Indus and the Jhelum drawn above there are a number of other differences between the two rivers which are significant from the power point of view. There is an important difference in the time when flows start to rise to a summer flood peak and in the length of time that flood flows endure. The hydrographs of both rivers show a rising stage in the early spring entirely due to snowmelt, the Jhelum being the first to respond at the end of January and continuing to rise to its highest level in May, June and July. The Indus, together with the Kabul, on the other hand, start to rise later at the end of February and reach their highest snowmelt peak flows at the end of June, the Indus continuing to rise to a higher monsoon peak early in August. The Jhelum enters a falling stage at the beginning of August and the Indus towards the end of the month; this generally continues, with the exception of rare monsoon rain floods in September, to the end of the year. The winter base-flow discharge on both rivers is largely maintained by bank storage water contained in the valley alluvium and this regeneration makes an important contribution to the available water supplies in rabi.

A further difference between the flows on the two rivers is the very much higher silt content of the Indus. Almost all of the sediment inflow occurs in conjunction with the flood flows of the early summer. The generally accepted figure for mean-year sediment load on the Indus at Tarbela is 440 million tons -- equivalent to about 0.25 MAF compacted volume. Mean-year sediment transport on the Jhelum at Mangla on the other hand, is estimated at 72 million tons or about 0.04 MAF compacted volume. Whereas Mangla reservoir is expected to lose by siltation about 30 percent of its capacity in 50 years, it is estimated that the much larger Tarbela reservoir will lose 90 percent in the same period.

Existing Hydroelectric Installations

Of the 250,000 kw of hydroelectric potential which has so far been developed in West Pakistan about 60 percent is in the seven-year-old Warsak plant on the Kabul River and the remainder is distributed in a number of small installations located on irrigation canals or minor rivers in the Northern Grid area. The combined peak capability of the units is about 245 mw in summer and 155 mw in December. The characteristics of these various installations are summarized in Table 1.

Table 1

Existing Hydroelectric Stations

	No. of Units	Unit Size (mw)	Name Plate Rating (mw)	Actual December Capability (mw)
Warsak	4	40.0	160.0	100
Rasul	2	11.0	22.0	15
Dargai	4	5.0	20.0	15
Malakand	2	5.0)	19.6	15
	3	3.2)		
Nandipur	3	4.6	13.8	2
Chichoki Mallian	3	4.6	13.8	2
Shadiwal	2	6.75	13.5	3
Kurramgarhi	4	1.0	4.0	2
Renala	5	0.22	1.1	1
TOTAL			267.8	155

The Warsak station near Peshawar which was commissioned in 1960, contains four 40-mw units. Each unit is capable of generating 40 mw at normal operating head, using a discharge of 4000 cusecs. Natural river flow is insufficient to sustain all four units at 100 percent capacity factor from the latter part of September to the early part of April. The reservoir initially had pondage of only about 23,500 acre-feet and this has been reduced by siltation to an estimated 15,000 acre-feet or less. The minimum residual capacity of the reservoir has been estimated at 10,000 acre-feet. This should mean that some peaking capability will always be available. However, the peaking capability of the plant is in practice restricted at present to about 100 mw in winter from October through March because the large fluctuations in downstream flows which would result from peaking with the units at that time would endanger the temporary bunds built in the river each year for irrigation purposes some distance below the dam.

The other eight hydroelectric stations in existence are all low-head, low-capacity plants and, since they are located mainly on canals, their output is governed by irrigation requirements rather than by system peak demands. For this reason their contribution to the power supply cannot always be relied upon; they can be put out of service, for instance, by unanticipated canal closures. The December capabilities of these so-called 'small hydels' given in Table 1 are based on the water releases ordinarily expected in December.

Hydroelectric Potential of West Pakistan

To put even a rough figure on the total hydroelectric potential of an area is an almost impossible task. Some of the

uncertainties surrounding estimates of reserves of energy-producing minerals were discussed in Annex 4, which also cited an estimate of 10 million kw for hydroelectric potential of West Pakistan, noting that it was conservative. Any estimate of hydroelectric resources is subject to great uncertainties, though of a somewhat different nature from the uncertainties surrounding mineral reserve figures. It is less a question of possible new finds, more one of possible technological development in the design of dams which may make it possible to realize the full hydroelectric potential of a river. It is clear from the discussion of streamflow and river elevations in the preceding paragraphs that the ultimate hydroelectric potential of West Pakistan could be much higher than 10 million kw. It has been suggested 1/ for instance that full hydroelectric development of the Indus Gorge alone might involve the eventual construction of a series of seven high-head dams with a total installed capacity of about 30 million kw. Whether it will ever become technically and economically feasible to build such a series of dams are questions that will probably not be answered until future centuries. Besides the Indus Gorge itself there are a very large number of other potential hydroelectric dam sites in West Pakistan, especially on some of the tributaries of the major rivers discussed in this annex; these sites are listed and discussed in the report by the dam sites consultant; 2/ the vast majority of them are no more than locations that appear to have the basic topographical features that are, with present technology, required to make the construction of a dam even prima facie feasible.

There are, however, a number of dam sites in West Pakistan that have been surveyed with sufficient thoroughness to make them potential contenders for construction before the end of the century; Table 2 lists the principal among these. For comparative purposes, the table includes Mangla Dam on the Jhelum, considerably more than a 'contender' in that it is now very near to completion. An important possibility over the next twenty to thirty years is to raise Mangla 48 feet which would permit its live storage capacity to be increased by about 3.6 MAF. The main possibilities on the Indus are the very thoroughly investigated Tarbela project and the much less fully known Kalabagh dam site, some 120 miles downstream of Tarbela. A possible project following Tarbela would be side valley storage at Gariala on the Haro River, a minor tributary of the Indus. Finally, there is the Kunhar project, consisting of two dams in series on the Kunhar River (a tributary of the Jhelum) some 125 miles north of Mangla

1/ A.V. Karpov, "High Rockfill Dams in the Himalayas (Industrialization and Agricultural Productivity of West Pakistan) -- Optimum Energy Generation and Utilization." Indus Magazine (WAPDA), November-December 1965.

2/ Chas. T. Main International, "Program for Development of Surface Storage in the Indus Basin and Elsewhere within West Pakistan," in 6 volumes (August, 1966).

Table 2

Power Potential of Some Principal Possible Dams

	Full Supply Level(ft.)	Minimum Reservoir Level(ft.)	Initial Live Storage b/ (MAF)	Approximate Net Head (ft.) a/ Full Reservoir	Approximate Net Head (ft.) a/ Minimum Reservoir	Ultimate Number of Power Units envisaged	Power Units nominal rating(mw)	Approximate Capability One Unit(mw) Full Reservoir Level	Approximate Capability One Unit(mw) Minimum Reservoir Level
Jhelum River									
Mangla	1202	1075	4.9 c/	352	227	8	100	130	65
	1202	1040	5.3 c/	352	192	8	100	130	47
High Mangla	1250	1040	8.9 c/	403	227	8-10	100-125	134-165	47
	1250	1175	4.9 c/	403	335	8-10	100-125	134-165	124
Indus River									
Tarbela	1550	1300	9.3	435	185	12	175	200	38
	1550	1332	8.6	435	217	12	175	200	61
Kalabagh	925	825	6.4	220	120	9+	110	117	41
Haro River									
High Gariala	1250	1070	7.6 d/	340	160	6	85	90	33
Kunhar River									
Suki-Kinyari/Paras			0.128	3000(±)	3000(±)	4	110	122	110
Naran/Suki Kinyari			0.250	1100(±)	1100(±)	3	40	50	40

a/ Not a single value, but one which will vary with both unit and total discharge and with erosinn of original control section.

b/ Does not include streamflow available for power generation.

c/ These include 0.4 MAF in Jari arm below Mirpur saddle which can be used for irrigation purposes but not for power generation until a cut is made through the saddle. From power point of view Mangla has live storage of 4.5 MAF (minimum drawdown level 1075') or 4.9 MAF (minimum drawdown level 1040').

d/ Streamflow negligible.

in the Kaghan Valley. The maximum total installed capacity of the different projects listed in Table 2 is about five million kilowatts.

Surface Storage for Irrigation Purposes

A large part of the need for the construction of dams on the Indus and its tributaries arises from the requirements of agriculture for additional supplies of irrigation water, as indicated by the relatively large amounts of live storage envisaged in Table 2 behind most of the dams listed. The main purpose of the Mangla Dam is in fact to replace the rabi irrigation supplies which have been available to Pakistan from the Ravi and the Sutlej but which are allocated to India under the 1960 Indus Waters Treaty. The main purpose of subsequent surface storage development within this century will be to reconcile the seasonal fluctuations of river flow with the conflicting seasonal variations in requirements of irrigation water. The present periods of shortage of irrigation water are generally between mid-October and mid-April. The irrigation consultant anticipates that, with the growth of cropping intensities, this period of shortage will gradually expand to include more of October, April and the early part of May. A later stage of surface storage development, which might perhaps come into effect around the year 2000, would be to build reservoirs for over-year storage, i.e. to store flows from years with high floods for use in years when surface water supplies were below average.

The irrigation and power benefits of dams built to create reservoirs which would meet this need for seasonal storage are inseparably intertwined. Therefore the approach adopted by the Bank Group and its consultants in the evaluation of the various projects listed in Table 2 was to prepare various estimates of future requirements of electric power and of stored water for irrigation purposes, to devise alternative sequences of dam projects for meeting these two sets of requirements and to select that series of projects which constituted the cheapest way of meeting them in present worth terms. Preliminary evaluations of this nature indicated that the relevant projects for the twenty-year period under study were Tarbela, Kunhar, possibly the raising of Mangla and possibly Kalabagh at the very end of the period as a sequel to Tarbela. Only a few elements of these early studies are presented in the following annexes; they focus almost entirely on Tarbela, Mangla and Kunhar among potential hydroelectric projects. Gariala and Kalabagh are treated at greater length in Volume III of the Bank Group's report (Program for Development of Surface Water Storage). Briefly, Gariala is a possibility only for second-stage storage on the Indus, as pointed out previously, and it has several disadvantages -- expensive conveyance channels from Tarbela Reservoir, very limited power capability due to lack of flow in the Haro, amongst others -- compared with Kalabagh. Kalabagh as first-stage storage on the Indus on the other hand, compares poorly with Tarbela (despite its possible lower total cost) because of its relatively smaller live storage and power capability and because of its

faster rate of siltation if operated without sluicing and lack of firm power if operated as a sluicing project. For these reasons, amongst others, the best sequence of storage on the Indus appeared to be Tarbela followed by Kalabagh if the choice had to be made on the basis of the present state of knowledge.

The Bank Group's Studies

Within the context set by these earlier analyses attention was focused at this stage of the Study on three specific sets of questions. First was the general problem of identifying the power benefits of Kunhar, Tarbela, and the 'Raise Mangla' project, investigating the sensitivity of these benefits to changes in assumptions regarding value of foreign exchange, fuel, etc., and considering the time when the projects should be implemented. The power benefits of Tarbela and Mangla, being multipurpose projects, depend intimately on how the reservoirs are operated, and these studies led directly into the second group of questions: assessment of the gain or loss to power from maintaining different minimum drawdown levels at the reservoirs. The third set of questions on which attention was focused concerned the scheduling of the introduction of additional units at the various hydroelectric stations; this was important for building up the tentative power development program presented in Volume IV -- and for studies on transmission -- but it had far less to do with agriculture than the first two groups of questions.

The Main Hydroelectric Projects Studied

The power benefits of Tarbela were defined in terms of the savings that would result from meeting forecasted power loads with a program including the Tarbela project rather than an alternative power development program. A number of alternative power programs were studied, in particular some including Kunhar and others excluding it. These programs are presented in detail in Annex 7. In order to make this kind of comparison, it was necessary to assume some specific minimum drawdown level at Tarbela and for this purpose, a minimum level of 1332 feet was selected. It was also necessary to assume some particular release pattern for Tarbela and for this purpose the release pattern finally recommended by the irrigation consultant was adopted. (Both of these points are discussed at greater length in later paragraphs of this annex.) Kunhar is of course a very different type of project from Tarbela; it is much smaller, but it would develop a much higher head than Tarbela and, any agricultural use that might be made of its storage being definitely a secondary consideration, its capacity and its energy output fluctuate much less over the year than would those at Tarbela. Table 3 sets out some of the chief characteristics of these two projects. The table illustrates the very large variation in the peak capability of the Tarbela units resulting from the fact that, due to release of water for irrigation purposes, the net head available would fluctuate between about 435 feet in August-November and 217 feet in early June. The fact that the annual

Table 3

Comparison of Kunhar and Tarbela Power Potential

	Tarbela (Drawdown: 1332')	Kunhar Project
No. and size of units	12 x 175 mw	4 x 110 mw 3 x 40 mw
Maximum capability (mw)	2,520 (Aug-Nov)	594 (July-Oct)
Minimum capability (mw)	732 (June 1-10)	491 (May)
Annual energy a/ (mln kwh)	12,500	2,900
Annual capacity factor b/ (%)	56	56
Cost per kw firm capacity c/ ($)	255	414
Cost per installed kw ($)	107	363
Foreign exchange component (%)	75	63

a/ Mean-year flows.
b/ Capacity factor is taken here to mean average capability over a period as a percentage of maximum capability in that period -- in the table on mean-flow year.
c/ Including transmission to Northern Grid (Lyallpur) in both cases, and including costs of dam in the case of Kunhar, but not in the case of Tarbela.

capacity factors of Kunhar and Tarbela with 12 units are identical is an odd coincidence. In fact the capacity factor at Kunhar would be relatively constant over the months at about 55-60 percent, whereas that at Tarbela would change from about 100 percent in May and June (when relatively small flows are required to keep the turbines running continuously at maximum output because of the low head) and in the flood season August-September to as low as 40 percent in November-December when the head would still be quite high (relatively small storage-releases having been made up to that time) but flows would be relatively low.

After consideration of these two projects in the context of power development programs modeled around them, attention was turned to the more specific question of the timing of Tarbela. For analysis of this question alternative complementary programs of power development and surface storage development were devised in a manner similar to that used in assessment of Kalabagh, but in this case one program included the Tarbela project in 1975 and the other had Tarbela in 1985. Both sets of programs were intended to meet the power requirements and the stored water requirements derived in other parts of the study and built up into an internally consistent overall development plan. The programs are described more fully in Annex 7. One of the major ways of compensating for the lack of Tarbela storage in the decade 1975-85 is by means of raising Mangla in 1975 and continuing to draw the reservoir down to 1040 feet each year. The higher reservoir level at the end of the flood season and larger releases through the winter that

would result from operating Raised Mangla in this way would make its power characteristics different from those of Low Mangla. Table 4 summarizes the power output in a mean year of High Mangla operated to a drawdown level of 1040 feet and, for comparative purposes, it indicates the mean year power characteristics of Low Mangla operated to a drawdown level of 1040 feet and of High Mangla operated to a minimum level of 1175 feet; a drawdown level of 1175 feet would mean that High Mangla would have approximately the same live storage as Low Mangla drawn down to 1040 feet. High Mangla drawn down to 1175 feet is discussed at greater length in Annex 8 below as a case of raising Mangla for power purposes.

Table 4

Comparison of High and Low Mangla Power Potential

(Mean Year)

	Low Mangla	High Mangla		
	drawdown 1040'	drawdown 1040'	drawdown 1175'	
No. and size of units	8 x 100 mw	8 x 100 mw	8 x 100 mw	10 x 100 mw
Maximum capability (mw)	1,100 (Sept)	1,180 (Aug-Nov)	1,180	1,480
Minimum capability (mw)	360 (April)	360 (May 1-10)	950	1,190
Annual energy (mln kwh)	5,800	6,250	7,800	8,100
Annual capacity factor (%)	60	60	75	63
Percent of total flows used (%)	90	85	98	100

This table again illustrates the great fluctuation in the capability of the units between times when the reservoir is full and times when it is fully drawn down. This fluctuation is of course much reduced if a higher minimum reservoir level is maintained, as indicated by the last two columns. The last line of the table shows the proportion of total outflow in the mean year (natural flows plus storage releases) which would pass through the turbines. The figures indicate that, with Low Mangla as presently under construction, eight units will be sufficient to use all but 10 percent of the mean year discharges through the dam. The 10 percent of discharges which will not be passed through the turbines will occur chiefly in February-May when the reservoir is low and therefore relatively small flows are required to keep the turbines running at 100 percent capacity factor. Maintenance of a substantially higher drawdown level would mean that more water could pass through the turbines at the time of minimum reservoir level, as illustrated by the third column of the table; in other words a higher proportion of total flows may then be used usefully for power generation.

Drawdown Levels at Tarbela and Mangla

The second set of questions studied concerned the drawdown levels at Tarbela and Mangla. Analysis of alternative drawdown levels

is a logical follow-up to the preparation of the general outlines of a program of dam developments for helping to meet power and stored water requirements. It was pointed out above that, in the preparation of such a program, a drawdown level of 1332 feet at Tarbela was assumed. The main criteria used to develop the joint surface storage/power programs were requirements of rabi irrigation water and of electric power developed elsewhere in the study; all alternatives considered had, in combination, to meet these requirements. But how valid are the requirements? Could greater benefit be derived from the reservoirs by, say, meeting the power requirements more fully and the irrigation requirements less fully? For storage dams are only one of the means that will be available in West Pakistan for meeting either requirement. Irrigation requirements may be met also by tubewells and power requirements may be met by thermal plants. Once the dams are constructed there will be a choice between drawing the reservoirs down fully each year, thereby making all the contents of the reservoir available for agriculture, and retaining some water in the reservoir throughout the year, thus maintaining a higher head on the turbines so that more power can be generated. Study of drawdown levels is thus essentially a study of marginal differences in the allocation of the storage capacity between power and irrigation.

The question of the level to which the reservoirs should be drawn down at the end of the winter season each year is of course only a specific case of the general problem of choosing release and filling patterns for operation of the reservoir. The criterion which is relevant in the choice of drawdown levels is no different from the criterion which should govern the choice of release pattern over each of the months (and shorter periods) in the year: the value of the last acre-foot of water released from the reservoir in any period should be equal to the expected value of the last acre-foot of water retained in storage at the end of the period. No attempt has been made here to carry out the kind of detailed operational study, involving comparison of agricultural and power benefits at different times over the year, which would be necessary to reach an optimum release pattern. However, the release pattern finally adopted by the irrigation consultant, as discussed in a later section of this annex, was developed with a view to the competing claims of both power and irrigation. And, in practice, much the most important aspect of reservoir operation in West Pakistan from the point of view of long-term planning is the minimum level to which the reservoirs are drawn down each year.

The minimum level maintained at the reservoir will affect the amount of thermal generating capacity that has to be installed; Tables 3 and 4 indicated that the differences between minimum and maximum capability at Mangla will be very large and inspection of prospective loads shows that this difference is very large compared to likely differences between the power loads in different months, so that the critical period on the power system (i.e. the time when generating reserves are at a minimum) will occur when the reservoirs are fully

drawn down. Even though peak power load in the Northern Grid is at present about 50 mw higher in the winter than in the spring the installation of the first two units at Mangla alone will suffice to bring the critical period in power-system capability from December to the spring. By comparison with changes in minimum reservoir level, changes in the pattern of releases from the reservoirs over the months of the year will have a relatively insignificant effect on the power system; such changes will normally alter only the amount of hydroelectric energy available at different times and hence the amount of energy that has to be generated thermally in different months. Therefore, attention in these studies has been focused on the costs and benefits to power and to agriculture of releasing more water over the year as a whole (according to a predetermined release pattern) as against retaining more water in the reservoir throughout the year. In other words, the approach is one of trying to get an indication of the direction in which the planned drawdown levels at Mangla and Tarbela should be shifted, if at all, in order to equalize the marginal benefits of the last few hundred thousand acre-feet gradually released over the course of the year and devoted to agriculture with the marginal benefits of the last few hundred thousand acre-feet retained in the reservoir throughout the year and thus allocated to power.

A number of different drawdown levels at Tarbela and Mangla were considered by the Bank Group, but effort was finally concentrated on analysis of two at Tarbela and two at Mangla in order to get an indication of the general order of priority of the claims of agriculture and power. The chief implications of these alternative drawdown levels -- 1040 feet and 1075 feet at Mangla and 1300 feet and 1332 feet at Tarbela -- for irrigation and for power are summarized in the following table.

Table 5

Alternative Drawdown Levels on Mangla and Tarbela Reservoirs a/

		Mangla (8 units)		Tarbela (12 units)	
Minimum Reservoir Level	(ft.)	1040	1075	1300	1332
Initial b/ Live Storage	(MAF)	4.90	4.50	9.30	8.60
Firm Capacity	(mw)	360 c/	504 c/	456	732
		(April 1 - May 1)		(June 1-10)	
Annual Energy	(mln. kwh)	5810	6033	12,000	12,400

a/ Data based on manual simulation of reservoir operation (see Appendix 1).
b/ i.e. excluding effect of siltation, and, for Mangla, excluding the storage capacity of the Jari Arm.
c/ Firm capacities given here are those used as firm capacities in construction of alternative power development programs. They correspond to capabilities of 45 mw per unit and 63 mw per unit, which are each 5 mw less than the capabilities given in Appendix 1 for the minimum 10-day period. These more conservative figures for firm capability were adopted for purposes of capacity planning because of uncertainty as to the precise capabilities of the turbines at low reservoir levels (see Appendix 1 below, especially p. 33).

It is clear from the table that the main effect, from the power point of view, of maintaining a higher drawdown level, is to increase the firm capability of the power units; the effect on energy output is relatively small.

The power consultant evaluated the benefit to power of maintaining the higher rather than the lower drawdown level at each reservoir by considering the thermal equipment that would be needed to provide an equivalent amount of firm capability and the fuel that would be required to generate the energy which would be lost without the higher drawdown level 1/. Using an 8 percent interest rate and assuming 35-year life for thermal equipment and 50-year life for transmission equipment, he computed an annual fixed cost for thermal capacity (and any necessary transmission) required to make up the difference in capacity, and he estimated the annual maintenance costs for the plant and the costs of the thermal fuel required to produce the energy lost by drawing down to the lower level. The sum of these annual costs divided by the amount of irrigation water sacrificed gave an annual figure per acre-foot, for comparison with the benefits that could be obtained from using an acre-foot for irrigation. Using a fuel price of about 12 cents per million Btu, he concluded that the benefit to power of water retained at the lower levels in Tarbela would be worth about PRs 35 ($7.30) per acre-foot per year, and the equivalent figure for Mangla would be about PRs 26 ($5.60) per acre-foot per annum.

The Bank Group adopted a somewhat different approach. It devised alternative power programs, some on the assumption that, for instance, Tarbela would be held at 1332 feet, others on the assumption that it would be drawn down to 1300 feet, and with the aid of the computer model of the power system, it simulated the operation of the resultant power programs over the years and secured an indication of the differences in total system costs involved. The power consultant made his calculations simply in terms of the amount of thermal equipment required to compensate for the lower drawdown level when all twelve units at Tarbela (or all eight at Mangla) were installed; in fact, of course, the 'saving' in thermal capability which results from maintaining the higher drawdown level builds up gradually over time as additional units are installed. But the value of the saving is probably greater than the 35-year annual charge figures imply because it takes the form of eliminating the need for relatively heavy capital outlay at the time the hydro units are installed; and thereafter the effect on the power program is that the need for further capacity additions is always postponed by a year or two so long as the higher minimum drawdown level is maintained. Though less important than the effect on the need for thermal capacity, the effect of a higher minimum

1/ Since most of the additional energy which can be generated at the higher drawdown levels is related to the higher capability available in the critical period each year it is usable energy; i.e. if it were not available then thermal plant would have to be used to generate the same amount of energy.

drawdown level on the availability of energy at different times is significant and it is complex. Besides the main increase in energy available, which would occur around the critical period of lowest drawdown, there would also tend to be some increase in the late flood season as a result of reduced retention for storage, some increase in mid-winter as a result of higher reservoir levels and some reduction in the later part of the winter as a result of reduced releases. The real value of these various changes in the availability of energy would depend on the monthly pattern of demand, and that value could change significantly as the result of adding additional hydro capacity which had a different monthly pattern of energy production. The result of computations with the aid of the simulation model is a present-worth value of maintaining the higher drawdown level, taking into account the various capital, maintenance and fuel costs that would be saved and the years when they would be saved. Figures of this sort are cited in the annexes which follow for Tarbela and Mangla.

Neither the 'annual charge per acre-foot of water' approach nor the approach on the basis of the power system simulation model come to grips with the full complexity of the drawdown-level problem from the power point of view. The simulation approach results in a reasonable estimate of the present worth of the costs to Pakistan of drawing down to a lower minimum level rather than a higher one in every year of the Plan period. This is useful for comparison with the present worth of the benefits to agriculture from releasing the additional water each year for irrigation purposes. Such a comparison can be a valuable check on the validity of the storage program planned and it can be an indicator of the general order of priority that should be assigned to the claims of agriculture and power in the operation of the reservoirs. But the drawdown level on the reservoirs is not a question that has to be precisely defined before construction of the dams; it is open to decision each year. Yet, for the annual operating decision the power consultant's assessment of the benefit, though it is given as an annual value per acre-foot of water, is not very helpful either. It is clearly only an average value of the savings potentially available.

In practice, the savings to be had from maintenance of the higher drawdown level are likely to vary considerably among different years. In some circumstances -- say when additional hydroelectric capability is to be added to the system -- the savings could be above average, and in other circumstances -- say soon after additional base-load hydro units have come on line -- the savings could be much less. Very much the same considerations will apply on the agricultural side: the benefits of drawing down Tarbela to 1300 feet rather than 1332 feet would likely be lower right after completion of the reservoir than say, ten years later when the farmers have absorbed the water more fully and additional storage capacity is about to be added to the irrigation system. Moreover, wise decisions about the drawdown levels at Mangla and Tarbela that should be used for planning additions to system capability cannot be made without paying some attention to hydrological probabilities: what are the chances, for instance, that a year may have sufficiently high natural flows so that the higher

drawdown level could be maintained without any detriment to agriculture? And what would be the consequences for power if a decision to maintain the higher drawdown level had to be reversed at the last moment because the year in question turned out to be one of low flows? These points are discussed somewhat more in the following annexes.

Scheduling the Installation of Hydro Units

The third set of questions in connection with the hydroelectric projects which required attention concerned the number of turbines to be installed at Mangla and Tarbela and the scheduling of their installation as well as that of two additional units which might be added at Warsak. Four tunnels are planned at Tarbela and it would be physically feasible to add a fifth; present designs foresee four units on each tunnel that is dedicated to power uses and so it would be possible to install more than the twelve power units listed in Table 3 above. At Mangla five diversion tunnels have been built and, although the fifth tunnel is being temporarily plugged with a steel bulkhead, it would be physically possible to install a penstock and enlarge the powerhouse so that it could accommodate ten units instead of the presently envisaged eight. At Warsak inlet and outlet tunnels and space in the powerhouse already exist for addition of units 5 and 6.

The length to which it is worth carrying hydroelectric development at a particular site depends on a large number of factors but in particular on the heads that may be available and their variation over the year, on the flows that may be available and their fluctuations over the year and among different years, on the time pattern of demand for electricity, and on the type and extent of generating capability available elsewhere on the power system. As long as Mangla and Tarbela retain a relatively large amount of live storage capacity, i.e., for at least the next twenty years, and as long as stored water is released broadly in accordance with the release patterns assumed here, the heads available at different times of the year will fluctuate widely. Moreover, flows will vary widely both over the year and among years, as pointed out at the beginning of this annex. Storage at Low Mangla operated to 1040 feet will transfer about 21 percent of mean-year flows from the kharif season to rabi and result in more than doubling even mean-year discharges in the winter release period; it will increase critical-year discharges in that period by about 130 percent. Nevertheless, under mean-year conditions, total discharges will only be sufficient to run as many as eight units at Mangla with about a 40-50 percent capacity factor in November through January. Under critical-year conditions, discharges would only be sufficient to sustain about a 40 percent capacity factor on eight units through that period. Installation of an additional two units would lower the capacity factor about 10 percentage points in this period and add energy only in the March-May period. Thus, while installation of two additional units at Mangla would increase the proportion of flows used, to above the 90 percent envisaged in Table 4 as a result of increasing energy output in the minimum-reservoir period, it would only add peaking capability in

much of the year; this peaking capability would generally be more than the West Pakistan power system is likely to be able to use over the next ten to twenty years. This question is discussed further in Annex 8; it is introduced here to illustrate the importance of flows and their fluctuations and for contrast with Tarbela.

The conflict between full use of available flows and the requirements of the power system for relatively high capacity factor generation is considerably more acute at Tarbela than at Mangla. Reference was made early in this annex to the heavy concentration of natural flows on the Indus in the June-September period. Tarbela alone will make a much smaller impression on flows in the Indus than will Mangla on flows in the Jhelum. With a drawdown level of 1332, Tarbela's live storage of 8.6 MAF represents about 13 percent of mean annual flows. Transfer of this amount of discharge to the October-May release period will increase total outflows in that period by about 33 percent in the mean year and 50 percent in the critical year. Twelve units at Tarbela will only be able to pass about 60 percent of total mean-year flows in the Indus; flows in the June-September period, even after deduction of 8.6 MAF for storage, will remain far above the needs of the turbines at that time. Yet, even with mean-year flows plus storage releases for agriculture, twelve turbines will operate at only about 40 percent capacity factor in the October-December period.

As this discussion has implied, as further units are added at Tarbela and Mangla, their total energy contribution will drop off rapidly. Moreover, since the energy output is so heavily concentrated in the flood months, especially for the later units, the contribution of the units in terms of energy that can be absorbed immediately will fall even more rapidly as additional ones are added. The following table, based on the assumption that Tarbela will be drawn down each year to 1332 feet and Mangla to 1040 feet, gives an impression of the increase in the availability of hydro energy that will occur as units recommended in this report for addition to the system are added. The table shows that, as further units are installed at each of the dams, they add to energy output in fewer months of the year; the last units add energy only in the spring (when the reservoirs are fully drawn down) and the summer (when there are flood flows).

The scheduling of addition of units at the hydroelectric stations is considered in both a qualitative and a quantitative way in the following annexes. The correct schedule will depend on the rate at which the load grows, on its pattern(i.e. how much hydro-peaking capability can be usefully absorbed in some months) and on the cost of alternative means of generation, particularly the cost of fuel for thermal generation. The power system simulation model was used to compare alternative schedules of unit installation for Tarbela, Mangla and Warsak; one particular example of its use for this purpose as related to the Tarbela evaluation is elaborated at the end of Annex 7.

Table 6

Output of Hydro Units Included in Proposed Program

		Maximum Capability (mw)	Annual Energy in Mean Year a/ (mln kwh)	Months of increased availability of energy	Annual Capacity Factor (%)
Mangla	1 and 2	276	1818	Jan - Dec	75
	3 and 4	276	1789	Jan - Dec	75
	5 and 6	276	1308	Feb - Nov	54
	7 and 8	276	798	Feb - Oct	33
Tarbela	1 and 2	420	2858	Jan - Dec	78
	3 and 4	420	2858	Jan - Dec	78
	5 and 6	420	2651	Jan - Dec	72
	7 and 8	420	1959	Jan - Oct	53
	9 and 10	420	1573	Feb - Sept	43
	11 and 12	420	1255	Mar - Sept	34
Warsak	5 and 6	80	304	Apr - Sept	43

a/ These figures do not correspond precisely with those given in previous tables in this annex because they are based on slightly different assumptions regarding the distribution of flows over the year.

Simulation of Reservoir Operation

In order to study the three sets of questions discussed above it was necessary to have some means of simulating the operation of different sizes of reservoir, drawn down to different minimum levels or to different release schedules. The irrigation consultant had developed a computer program as a means of testing the implications of different reservoir operating rules for the power capabilities and the energy output of the Tarbela and Mangla power plants. The Bank Group wished to test the effect of various changes in assumption regarding system operation and to consider various additional alternative hydroelectric developments. For this purpose, it used a manual simulation approach basically very similar to the approach underlying the computer program but simplified in a number of relatively unimportant respects. The two approaches are described in detail and compared in Appendix I, which also shows the more important of the data regarding the hydroelectric stations' capabilities and energy outputs which were drawn from the reservoir operation studies for use in the power system simulation model. This Appendix also includes the main data used regarding the hydroelectic potential of Kunhar and Warsak; figures for these plants were taken directly from the power consultant and from Harza.

In the Bank Group's manual simulation the operation of Mangla and Tarbela Reservoirs was simulated by ten-day periods throughout the year. A fixed release pattern was used (discussed further in subsequent paragraphs of this annex). Reservoir content at the beginning of each ten-day period was derived by subtracting releases during the previous ten-day period from the reservoir content at the beginning of that period (or, in the filling period, adding net inflows during the period to the reservoir content at the beginning of the previous period). The elevation of the reservoir at this time could then be read from a curve relating reservoir content to reservoir elevation. Addition of releases to natural flows in a ten-day period (or subtraction of amount required for filling during filling period) indicates the total outflow through the dam to be expected in this ten-day period and comparison of this with the discharge capacity of the number of turbines assumed installed indicates the extent to which the turbines can be operated during the ten-day period in question. The resultant 'Operation Factor' (or available discharge as a percent of maximum discharge capacity 1/) can be multiplied by the maximum amount of energy that would be available from the turbines if they were operated continuously through the ten-day period at maximum load, given the head available, in order to derive a figure for the actual amount of energy available in the period.

The Release Pattern

From this brief description of the simulation of reservoir operation it is clear that the release pattern used will affect the head available on the turbines at different times of the year and it will also affect the amount of discharge in any ten-day period. A change in release pattern may therefore affect both the peak capability of the units and the energy that they can produce in a period. In practice, as pointed out previously in the discussion regarding drawdown levels, where the capability of the hydroelectric stations will fluctuate over the year as greatly as it will at Mangla and Tarbela, changes in either capability or energy output of the units during the bulk of the release period will affect only the amount of energy that has to be generated thermally; they will not affect the amount of thermal capability that must be installed in order to meet loads.

For the purposes of its studies, the Bank Group adopted fixed release patterns for Mangla and Tarbela. A 'fixed' release pattern means that a fixed proportion of live storage is assumed to be

1/ The Operation Factor cannot of course be greater than 100, for there is a limit to the amount of water that can be discharged through the turbines at any given head. If more water must be passed through the dam (e.g., to meet downstream irrigation requirements) then the excess over the discharge-capacity of the turbines must be passed by the spillway or by the irrigation release valves.

released in a period in addition to all natural flows during that period. An alternative approach to the regulation of a storage reservoir is what might be called the 'fixed total outflow' approach: stored water is drawn upon as necessary to supplement natural flows and bring total outflow through the dam up to some predetermined target in any period. The 'release pattern' approach has the disadvantage of being inflexible; it can result in the squandering of surface water by releasing too much in some months when river inflows are above average. The 'fixed total outflow' approach, on the other hand, can result in the premature emptying of the reservoir, so that irrigation supplies and generating capacity are severely curtailed at the end of the release season. In practice, it should be possible to work up some combination of these two approaches -- specifying, for instance the end-of-period reservoir content implied by the fixed release pattern as a minimum which might, however, be exceeded as a result of releasing less stored water in the event of natural river flows in a particular period being above average.

The fixed release patterns adopted for the Bank Group's power studies were in fact those finally recommended by the irrigation consultant after comparison between a large number of alternatives. These release patterns were derived primarily with a view to the needs of agriculture for supplies of surface irrigation water. They were developed mainly on the principle of spreading surface water deficiencies in a year of low rabi flow 1/ evenly throughout the release period as a proportion of the total irrigation requirement, the deficiencies being met by temporary overpumping of groundwater in certain canal commands. The attempt was made to concentrate regular pumping of recharge to the groundwater aquifer in the period October through March, when the combined power capabilities at Mangla and Tarbela will be greater than they will be at the end of the release season in April-May. Somewhat heavier reliance on groundwater supplies for irrigation in the early part of the winter than in the later part has the added advantage of keeping up the reservoir level and the head on the turbines a little higher than would otherwise be possible.

Since these release patterns have been developed on the basis of low rabi flow-years they indicate approximately the maximum

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1/ The irrigation consultant considered that critical-year flow conditions were too severe for use in developing rules for reservoir operation and therefore he composed a synthetic stream-flow sequence, entitled 'low rabi year' specifically for this purpose. The lowest 50 percent of the monthly flows on each river in October to May during the 41-year period of record were averaged and the resultant flows were adopted as low rabi flows. Low rabi flows in the October-May period on the Jhelum were taken as 9.15 MAF compared with 8.59 MAF critical year flows (1954/55) and 10.88 MAF mean-year flows. Low rabi flows on the Indus (at Attock) in the same months were taken as 23.61 MAF compared with 17.84 critical year flows (1954/55) and 26.09 MAF mean-year flows.

amount of releases that the irrigation consultant considers to be warranted in the early part of the release season and hence the minimum reservoir levels that should be maintained at different dates through the winter. Thus the estimates of the time pattern of hydroelectric capability which correspond to this pattern of minimum reservoir levels should be conservative. In years when natural flows are greater than those of the low rabi year the actual capabilities should be greater.

Table 7 shows the final Tarbela and Mangla release patterns adopted by the irrigation consultant and compares them with those used by Harza in some of their computer studies.

Table 7

Tarbela and Mangla Release Patterns
(% of live storage:
positive figures = releases;
negative figures = storage)

	Mangla		Tarbela	
Month	Harza	IACA	Harza	IACA
October	17	23	8	0
November	16	15	10	8
December	14	10	10	11
January	14	10	15	21
February	20	24	23	26
March	18	18	20	19
April	-12	0	14	10
May	-18	-24	-30	5
June	-23	-36	-50	-45
July	-27	-31	-10	-55
August	-20	- 9	-10	0
September	0	0	0	0

The irrigation consultant estimates that the seasonal demand for storage at Mangla will be concentrated in the six months from October to March with high peaks in October and February. At Tarbela the period of storage demand would normally be from November to the beginning of April in 1975 and to the end of April by 1985. The comparative figures for the Tarbela release pattern in the above table illustrate the emphasis that IACA places on using groundwater pumping at the beginning of the rabi season to reduce the need for storage releases at that time and thus to maintain a higher reservoir level until the end of February. Because of the great variability in flows on the Indus and the consequent possibility that storage releases could be required even up to the middle of May, IACA also recommends retention of about 5 percent of live storage at Tarbela through the end of April as an insurance against low spring flows. As regards Mangla, IACA has a somewhat higher release than Harza at the beginning of the rabi season in October, but this results from the combination of low natural flows on the Jhelum and the Chenab in that month and high irrigation demands during the overlap of

kharif and rabi crops. IACA estimates 1/ show that, even with a 23 percent release in October, potential deficiencies which have to be made up by pumping are large compared to those of other months. During February and March the peak crop water requirements occur. As regards filling of the reservoirs the irrigation consultant's studies indicated that the balance between flows and downstream irrigation demands in the spring was such that filling could not be reliably expected to begin before May at Mangla and June at Tarbela -- or one month later than Harza had projected. However, once filling was begun it might proceed more rapidly.

Hydrological Uncertainty and Peaking Capability

All the figures regarding the capabilities and energy outputs of the hydroelectric units at Tarbela and Mangla which have been presented in the tables in this annex related to mean-year flow conditions, and this is indicative of an important difference between the approaches to defining the hydroelectric characteristics of these dams which were adopted by the Bank Group and its consultants. Both the Bank Group and its consultants adopted mean-year flow conditions for developing the figures on hydroelectric capability and hydroelectric energy which were used in analyses of system dispatch; equally both the Bank Group and its consultants adopted critical year conditions for developing figures regarding the firm capability of the hydroelectric units for use in planning additions to system capability. However, the Bank Group took the view that it would not be necessary to restrict the peaking capability of the units whereas its consultants had assumed that peaking would be restricted to certain fixed levels, and this makes for a significant difference in assessment of capability in the critical year at the time of system minimum capability.

Peaking at these multipurpose reservoirs essentially involves storing some water over a day and then releasing a large quantity in a short space of time, as contrasted with maintaining an even discharge over the day. With the even discharge the turbines can be run to produce a steady flow of energy but at low load; with the concentrated discharge the steady flow of base-load energy will be reduced but the units will be able to make a larger contribution to meeting peak power loads of short duration. The sharp fluctuations in discharges which occur in connection with peaking operation of the units could result in surges downstream which might cause undesirable scouring or other damage.

For the purpose of their studies the consultants assumed a 20 percent limit on peaking at Mangla and a 30 percent limit on peaking at Tarbela -- which means, in other words, that peak discharges could not be more than 20 percent (or 30 percent) in excess of average

1/ IACA Comprehensive Report, Volume 5, Annexure 7 -- Water Supply and Distribution (May 1966), p. 105.

discharges, or, in terms of power-output, that average load on the turbines could not be less than 80 percent (or 70 percent) of peak load on them. Generally speaking, under mean-year conditions, with twelve units installed at Tarbela with a drawdown level of 1332 feet and eight units installed at Mangla with a drawdown level of 1040 feet, this limit only becomes effective in the early part of the release period, i.e., October-February, the season when flows are relatively low. However, under critical year conditions the limit can become effective much later in the year, even at the time of system minimum capability. Table 8 illustrates this point. The capabilities given reflect directly the heads available on the turbines at the beginning of each ten-day period, without any reduction on account of lack of flows. The capacity factors indicate available flows as a percentage of the flows that would be required to run the units continuously at the loads listed for each period.

The effect of introducing the limits on peaking used by the consultants would be to restrict these capacity factors to a minimum of 80 percent in the case of Mangla and a minimum of 70 percent in the case of Tarbela by scaling down the peak loads to the degree necessary. It is clear from the table that the need for this scaling down would not generally arise during these months under mean-year flow conditions; the capacity factor is usually above the lower limit. However, it would arise sometimes under critical year conditions. An instance would be in the first ten days of May at Tarbela. The table indicates that critical year flows (plus releases in that period) are sufficient to sustain the peak load of 876 mw for only 66.8 percent of the time -- or, in other words, an average load of about 585 mw. Observance of the 30 percent limit on peaking would mean that peak load could only be 30 percent above this or about 760 mw.

It may well be, of course, that the appetite of the power system for peak power supplies will generally be too small (given the size of loads, the importance of Mangla and Tarbela capabilities in the overall system and the amount of other generating capability in the system) to make it worthwhile running Tarbela and Mangla units for peaking service. However, there does not appear to be any physical obstacle to peaking with them, and so, for the purpose of planning capacity additions, the Bank Group assumed that full peaking capacity would be available at Mangla and Tarbela. Given this assumption and the assumption of a fixed release pattern, the capabilities of the hydro units are identical in the critical year and the mean year, as implied by the table below, because they are dependent only on available head. However, firm capacity as used in the Bank Group's studies for capacity planning does still differ in one respect from capacity as used in the Bank Group's system dispatches: firm capacity is taken as system capacity in the minimum ten-day period whereas the dispatch is performed on the basis of average capacities in each month.

The only restriction on peaking at Mangla and Tarbela that can now be foreseen is in connection with the requirements of the Upper Jhelum Canal, which will be supplied from Mangla; but the requirements of this canal are small compared to the discharges of eight units

Table 8

Effect of Critical and Mean-Year Flows on Power-Production at Tarbela and Mangla at Time of System Minimum Capability

	MANGLA (8 Units) 1040' a/				TARBELA (12 Units) 1332'			
	Mean-Yr. Flows		Critical Yr. Flows		Mean-Yr. Flows		Critical Yr. Flows	
	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor
Mar 1-10	672	100.0	672	71.5	1608	66.2	1608	59.6
Mar 11-20	584	100.0	584	92.5	1476	74.0	1476	67.6
Mar 21-31	512	100.0	512	100.0	1296	84.4	1296	74.0
Apr 1-10	400	100.0	400	100.0	1128	74.0	1128	61.9
Apr 11-20	400	100.0	400	100.0	1044	81.4	1044	68.4
Apr 21-30	400	100.0	400	89.2	936	100.0	936	73.3
May 1-10	400	100.0	400	66.6	876	100.0	876	66.8
May 11-20	536	100.0	536	66.2	828	100.0	828	80.1
May 21-31	664	100.0	664	64.4	768	100.0	768	100.0

at Mangla and so, although allowance was made for this in the Bank Group's studies, it does not in fact alter the conclusions drawn above. Mangla will probably have to be operated in such a way as to maintain a uniform flow in the Upper Jhelum Canal; flows in excess of this amount released during peaking periods or during periods of high flow will simply return to the Jhelum River by way of the new Bong Escape. The dam sites consultant considers that the regulation afforded naturally in the Jhelum River Channel above Rasul Barrage, together with small permissible fluctuations (less than six inches) of the barrage pond will be sufficient to prevent any foreseeable degree of peaking at Mangla from interfering with steady irrigation withdrawals at Rasul Barrage to the Lower Jhelum Canal and Rasul-Qadiribad Link Canal. Therefore, for purposes of the power system simulation model the units at Mangla were divided into two groups (as described more fully in Appendix I) -- those whose discharges would be required to meet the requirements of the Upper Jhelum Canal so that they must be run continuously on base load and the remainder (generally 5 or 6 out of a total of eight units) which could be peaked to an unrestricted degree. At Tarbela there would not appear to be any danger of sudden surges in the river resulting from peaking causing damage to downstream structures or interfering with irrigation supplies; therefore it was assumed that the Tarbela units could be peaked as and when necessary.

There is another aspect of hydrological uncertainty that is sufficiently important that it must be given some explicit attention. This concerns the use of tubewells for making up deficiencies in

a/ The Mangla capabilities shown here may be somewhat too high and the capacity factors slightly too low because they are based on the Bank Group's reservoir simulation which assumed a low tailwater level (see page 33 below). The text remains correct.

irrigation supplies in poor hydrological years. The irrigation consultant envisages temporary overpumping in years of low flow which would be balanced by the additional recharge to the groundwater aquifer in years of high flow. The power consultant estimated the additional pumping load that would be involved in a critical hydrological year. Table 9 shows the figures on a Province-wide basis for the two key years 1975 and 1985.

Table 9

Additional Pumping Load (mw) in Critical Year

	Jan	Feb	Mar	Apr	May	June (mw)	July	Aug	Sept	Oct	Nov	Dec
1975	12	35	32	26	30	34	5	0	55	44	14	8
1985	49	68	215	87	130	124	15	0	55	72	48	36

The power development programs discussed in the following annexes do not include explicit provision for covering these loads, since the power programs are all based on a fairly comfortable reserve-criterion: 12 percent of thermal capability and 5 percent of hydro capability. It is assumed that these occasional additional pumping loads would be met from reserve generating capacity. Most of the power programs considered include systemwide reserves in the order of 250 mw in 1975 and 500 mw or above in 1985, so that they would seem to be capable of coping with any additional pumping requirements resulting from low flows. The fact that the additional pumping requirements would occur at the same time as the shortage of hydro energy should result only in the need to generate more energy thermally, given the relatively high capacity factors on the hydroelectric units indicated in Table 8 even for critical year conditions.

Reservoir Siltation and its Effects on Power

It was pointed out at the beginning of this annex that the live storage capacity of Tarbela is likely to be depleted rather rapidly as a result of siltation. However this factor has not been taken into account in the Bank Group's simulation of reservoir operation. It has been neglected partly because of the uncertainty about the rate at which siltation will take place and about the precise effect that it will have on power capabilities and energy production and partly because the effects that can be anticipated are not likely to be very significant within the first ten to twenty years of the life of the reservoir.

The effects of siltation on the capabilities of the units at Tarbela and on the energy available from them will depend upon two important factors -- the pattern of deposition of the sediment and the way in which the resultant change in the live storage capacity of the reservoir affects the choice between releasing more water for irrigation

and retaining it in the reservoir to maintain a higher head on the turbines at the time of minimum reservoir level. The pattern of sediment deposition in a reservoir is hard to predict with any exactitude. It depends on factors such as reservoir shape, average detention time, grain size distribution of the sediment, the temperature of the reservoir water relative to the temperature of the inflowing water, the reservoir depth at the times heavily sediment-laden flows enter the reservoir, the depth of annual reservoir drawdown level, and the timing and rate of discharge through outlets near the bottom of the reservoir relative to river inflows. The dam sites consultant assessed the situation at Tarbela and reached the conclusion that the sand component of the sediment load (about 60 percent of the total) would tend to settle quickly and be deposited near the upper end of the reservoir at the then existing level while the silt (the remaining 40 percent) would settle more slowly and be deposited in thinner, more extensive layers mantling the bottom and sides of the reservoir. In time, as reservoir sedimentation progressed, the sand-front would tend to advance, delta-style, towards the dam.

The main effect of siltation on the output of power from Tarbela during the first ten to twenty years of the life of the project is in fact likely to be only a gradual reduction of the energy output in the winter release period -- which will be compensated by somewhat greater use of then existing thermal equipment for generation of energy. The decline in energy available from Tarbela in this period will result from reduction over the years in rabi outflows through the dam as less stored water is available for release due to depletion of live storage capacity. Chas. T. Main has estimated that about 50-60 percent of the sediment retained in the Tarbela Reservoir during the first ten to twenty years of its life will settle in the live storage area and that live storage will consequently be reduced from 8.6 MAF initially (with drawdown level of 1332 feet) to about 7.4 MAF after ten years and 6.0 MAF after twenty years. The computer model developed by the irrigation consultant for simulating the operation of the reservoirs does allow for the effect of reduced releases on the output of the turbines. The figures resulting from some of their computer runs do give an indication of the order of magnitude of what may be expected to result from siltation. They show, for instance, that the mean-year energy output of twelve units at Tarbela might be reduced about 4 percent between 1980 and 1985 as a result of siltation or by about 250 million kwh. The reduction occurs entirely in the release period November-May, and primarily in January and February; energy is reduced in each of these months by about 60 mln kwh. The computer print-outs do also show a fall in the peaking capability of the units, particularly in January and February when the reduction is as much as 100 mw. However, this sharp reduction results mainly from the special restriction on peaking assumed in the computer simulation of reservoir operation and discussed above.

Over the longer term the effect of siltation on the power capabilities of the Tarbela units will be more positive because it will involve a gradual increase of the minimum drawdown level on the reservoir. Siltation in the lower levels will tend to raise the minimum

levels to which it is physically possible to draw the reservoir down -- to about 1332 feet within thirty years of the completion of the project and 1400 feet within forty years of completion, according to the dam sites consultant. However, even before these dates are reached the effects of siltation may be such as to prompt a gradual increase in the minimum levels to which the reservoir is drawn down. In the first place, as siltation proceeds, the gain in irrigation supplies obtainable by drawing down to a lower minimum level rather than a higher one will gradually fall. Table 10 which is reprinted from Volume III illustrates this point.

Table 10

The Depletion of Tarbela Live Storage Capacity
(capacity in MAF)

Drawdown Level (feet)	1975	1985	2000
1300	9.3	7.9	5.6
1332	8.6	7.3	5.5
1350	8.2	6.9	5.4
1400	6.7	6.1	5.0
1500	2.7	2.5	2.45

The table shows for instance, that whereas about 0.6-0.7 MAF of live storage capacity would be lost to agriculture in the first ten years after completion of the project by drawing down to 1332 feet rather than 1300 feet, only about 0.1 MAF of live storage would be lost to agriculture by similar operation fifteen years later. At the same time there does not appear to be any particular reason why the power benefits of maintaining the higher drawdown level should fall. Hence the net value of keeping up the minimum reservoir level would seem likely to increase over the years. There is also another factor which may favor holding the reservoir above the physically feasible minimum level. Once the dead storage volume is filled with sediment -- and it is recognized that this could happen earlier than 2005, as presently projected, as a result of higher than expected sediment flows or unforeseen shifts in the sediment deposited in the reservoir -- the water discharged from the reservoir when it is fully drawn down will probably become heavily sediment-laden. The abrasive effects of sediment-laden flows on the turbines might become sufficiently severe to justify changing the minimum operating level of the reservoir so as to maintain a detention pond in which the heavier sediment particles would settle. Thus, over the longer term, the minimum capabilities of the Tarbela units will increase and the availability of power from the project should be much more evenly spread over the year than it will be initially; the extent to which it will be necessary to place the units in peaking service in the winter months will depend on available flows in that season which in turn will depend on the development of upstream storage.

APPENDIX I

RESERVOIR OPERATION AND HYDROELECTRIC PLANT DATA

The consultants studied the peaking capability and the electricity generation of the Mangla and Tarbela plants, simulating alternative operations of these reservoirs with a computer program. Several other alternatives were studied by manual simulation in the Bank. The purpose of these studies was to test the effect of various changes in the assumptions, and to complement the consultants' coverage of the subject. This appendix describes how each of these approaches to reservoir simulation derives figures on the power capabilities and energy output of the hydroelectric units from information on flows, release patterns, heads available on the units at different reservoir elevations and the turbine characteristics. It also sets out some examples of the data adopted from these studies for use in the simulation model of the power system, as well as data on other existing and potential hydroelectric projects.

The Consultants' Computer Program for Simulating Reservoir Operation

This computer program works in terms of ten-day periods. 1/ Given the reservoir live storage for any year and the reservoir release pattern -- percentage of live storage released or stored in each interval -- the computer calculates the reservoir content at the beginning of each ten-day period as the difference between the previous period's initial content and the release from storage (or addition to storage during the filling season) in that period. The total outflow from the reservoir is the sum of the natural flows and the releases (with 'releases' considered negative in the filling period). The gross head on the turbines is then obtained as the difference between the water level in the reservoir (headwater level) and the level downstream of the turbines (tailwater level). The headwater level is read from a table of reservoir level against reservoir content, whereas the tailwater level is calculated as a function of discharge. From the gross head, a loss figure is deducted, in order to obtain the net head. The loss is assumed to be 5 feet for Mangla and 7 feet for Tarbela. From the turbine characteristics, the computer reads the maximum available capacity against the net head. This figure is reduced by two percent to allow for generation losses and multiplied by the number of units to give the total peaking capacity.

However, before accepting the resultant figure as a correct indication of the capacity that will be available in a particular ten-day period, the computer checks on the flows available in order to see how much of the time the turbines could in fact be run at such a peak load. The assumption underlying the computer program is that peaking capacity is limited to two factors, the limit imposed by the machines and also insufficient discharge. The machine limit is given by the turbine characteristics, as indicated in the previous paragraph. Insufficient discharge is considered to be a limiting factor on the

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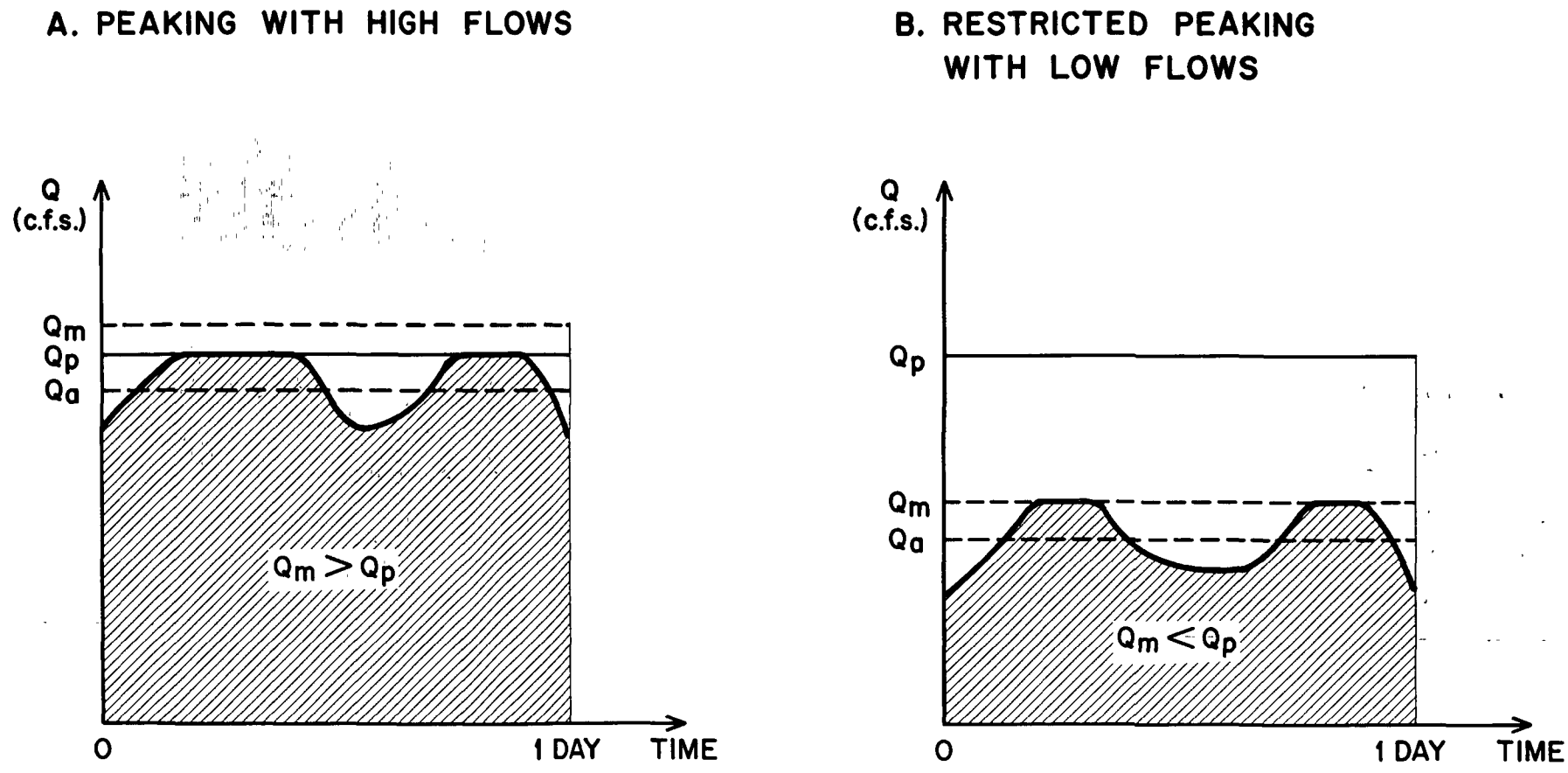
1/ i.e. three periods per month, diverging slightly from the ten-day standard in months with other than thirty days.

grounds that the releases from the reservoir should be rather evenly distributed during the day, in order to avoid surges in the canals and structures located downstream of the power station. The consultants allow for a 20 percent maximum increase above the average discharge for the Mangla Reservoir, and a 30 percent increase for Tarbela. The maximum capacity given by the turbine characteristic can be reached when the outflow (sum of the release and the natural flows) of a ten-day period is large enough to give a difference between peak and average discharges smaller than the said limit (20 percent for Mangla, 30 percent for Tarbela). Whenever the total outflow is small enough to cause a wider gap between peak and average discharges, the peak discharge is reduced by limiting the opening of the turbine gate; this obviously causes a reduction in the peaking capacity of the turbines. The ratio between the maximum allowed discharge and the peak discharge -- or discharge corresponding to the full capacity of the turbines -- is called reduction factor and is the ratio between the allowed peaking capacity (restricted peak) and the maximum peaking capacity (unrestricted peak).

Figures 1(a) and 1(b) give a schematic explanation of this peaking concept with a limit of 20 percent. Qp represents the peaking discharge, or the maximum discharge compatible with the net head on the turbine, Qa is the average available discharge over the time interval -- in the figures one day; the product of Qa (in cubic feet per second) and the number of seconds in one day, gives the volume (in cubic feet) which is available for passing through the turbines. Qm, or maximum allowed discharge, is defined as Qa plus 20 percent, or: $Qm = 1.2 \times Q$. In the case of Figure 1(a), large quantities of water are available, so that Qm is greater than Qp, and no reduction of the peaking capacity given by the characteristics, is necessary. In the case of Figure 1(b), however, the shortage of water brings Qm below Qp, and the allowed peaking capacity is reduced. Qm/Qp is the reduction factor applied to the peaking capacity given by the turbine characteristics.

The energy generated is machine capacity multiplied by time. Whenever there is an abundant outflow from the reservoir, i.e., the average discharge is equal to or greater than the peak discharge, the maximum capacity of the turbine can be maintained continuously, and the energy generated is capacity x time. Whenever the outflow is smaller, i.e. the average discharge is smaller than the peak discharge, the computer reads on the turbine characteristics the value of the optimum capacity, and no more of the peaking capacity. The optimum output corresponds to that opening of the turbine gates which generates the greatest amount of energy with a given quantity of water; this is the most efficient operation. The operation at peaking capacity would give a higher mw output but lower energy. With the maximum efficiency operation, the energy generated is optimum output multiplied by time and by the ratio between the discharge corresponding to this output (Qe) and the average discharge (Qa), or Energy = Optimum output x time x Qe/Qa. This practice assumes that in times of water shortage every effort will be made to run the machines at optimum efficiency. It is to be expected that peaking will take place for a short period every day; this will introduce a slight upward bias in the figure of energy generation which can be neglected for the present purpose.



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VOLUME IV
ANNEX 6-APPENDIX I
FIGURE 1

The computer prints out the values at the first, the 11th and 21st of each month, of the reservoir content, the net head on the turbines, their peaking capacity (restricted as described) and the reduction factor; it also gives for the ten-day interval starting at the same dates the amount of storage release, the maximum available energy and the unused flow.

This computer program was run with two different sets of hydrologic data for various key years -- 1970, 1974, 1975, etc. -- and with different assumptions regarding reservoir release patterns, drawdown levels, number of units installed, etc. The hydrologic data is shown in Table 1. Ten-day flows for the mean year were derived by averaging the monthly river flows of the 41-year period of record (1922-63), putting these figures on a chart and then drawing a smooth curve through them in order to indicate average flows in periods shorter than one month. Ten-day flows for a critical year were taken as the actual flows in 1954/55, which is the year of record showing the lowest October to May flow for the Chenab, Jhelum and Indus Rivers combined. Figures derived from the analysis on the basis of mean-year flows were taken to indicate the amounts of electric energy which would be available from the hydroelectric units while the figures from the analysis with critical-year flows were adopted for indicating peak capability available at the different times in the year. The reservoir operation was simulated for different specific years in the future because of the changes in live storage capacity of the reservoirs which are likely to occur as a result of siltation and because of some slight changes in release pattern which the consultants wished to study. Tables 2 and 3 are samples of the print-out from the consultants' computer study of reservoir operation: Table 2 shows the situation in 1985, with eight units at Mangla and twelve units at Tarbela, under mean-year flow conditions. Table 3 shows the results of a similar analysis based on critical-year flow conditions. It should be noted that the assumptions with regard to release patterns, minimum reservoir levels, etc. which underlie this particular run of the computer program are not the same as those finally adopted by the irrigation consultant and the Bank Group.

The Bank Group's Manual Simulation of Reservoir Operation

The basic procedures underlying this approach are similar to those built into the consultants' simulation program, but various simplifications and changes in assumption were made. The operation starts in October (the beginning of the hydrologic year) with full reservoir level. The available live storage is that of the initial year of operation; i.e. no allowance has been made for siltation. (See discussion of this point at the end of Annex 6.) The amount of water released from storage during each ten-day period is calculated according to the release pattern. The release patterns adopted for these studies (one for Tarbela and one for Mangla) were those finally proposed by the consultants after studying several alternatives (see Annex 6). The volume of water released is subtracted from the reservoir

Table 1

Critical and Mean Year Flows on Jhelum at Mangla and on Indus at Tarbela
(MAF)

	Jhelum		Indus			Jhelum		Indus			Jhelum		Indus	
	Critical	Mean	Critical	Mean		Critical	Mean	Critical	Mean		Critical	Mean	Critical	Mean
Jan. 1-10	.127	.168	.365	.355	May 1-10	.765	1.110	.568	1.022	Sept. 1-10	.782	.670	4.88	3.095
11-20	.122	.168	.346	.350	11-20	.80	1.220	.70	1.348	11-20	.558	.540	3.235	2.235
21-30	.121	.201	.315	.342	21-30	.82	1.260	.962	1.913	21-30	.456	.436	1.735	1.545
Feb. 1-10	.127	.245	.303	.347	June 1-10	.915	1.270	1.632	2.955	Oct. 1-10	.325	.340	1.44	1.087
11-20	.112	.281	.293	.358	11-20	1.04	1.290	3.215	3.765	11-20	.283	.278	.953	.840
21-30	.113	.307	.293	.372	21-30	.894	1.325	3.96	4.120	21-30	.253	.237	.689	.653
Mar. 1-10	.181	.438	.303	.394	July 1-10	.968	1.345	3.88	5.170	Nov. 1-10	.243	.197	.548	.572
11-20	.291	.510	.335	.416	11-20	1.0	1.245	4.48	5.420	11-20	.205	.173	.526	.506
21-30	.371	.610	.365	.492	21-30	.838	1.222	4.38	5.640	21-30	.175	.159	.496	.456
Apr. 1-10	.558	.765	.444	.584	Aug. 1-10	1.155	1.140	4.88	5.910	Dec. 1-10	.173	.155	.466	.418
11-20	.616	.878	.496	.645	11-20	1.215	1.000	6.05	5.210	11-20	.152	.165	.426	.400
21-30	.50	.986	.518	.810	21-30	1.153	.830	5.84	4.160	21-30	.141	.157	.386	.380
											18.548		60.703	
												23.321		64.285

ANNEX 6
Appendix I

Table 2

Consultants' Computer Simulation of Reservoir Operation - Mangla and Tarbela, 1985 - Mean Year Flows

	MANGLA (8 UNITS)							TARBELA (12 UNITS)						
	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (M.w)	Max Aval Energy (Kwh x 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (M w)	Max Aval Energy (Kwh x 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)
Oct 1	4.560	0.169	709.6	142.74	0.000	0.662	356.7	7.300	-0.	2151.1	415.24	0.000	0.888	430.9
Oct 11	4.391	0.150	689.0	140.54	0.000	0.651	353.9	7.300	-0.	1667.8	321.86	0.000	0 688	431.9
Oct 21	4.241	0.182	662.4	137.13	0.000	0.635	351.3	7 300	0.073	1444.6	278.74	0.000	0.596	432.4
Nov 1	4.058	0.196	610.5	127.38	0.000	0.593	348.2	7.227	0.146	1424.8	275.01	0.000	0.588	431.2
Nov 11	3.862	0.196	564.8	118.29	0.000	0 556	344.8	7.081	0.219	1426.7	275.62	0.000	0.589	428.8
Nov 21	3.666	0.192	529.8	110.98	0.000	0.529	341.5	6.862	0.219	1313.4	254.17	0 000	0.542	425.5
Dec 1	3.475	0.210	545.6	113.81	0.000	0.552	337 9	6.643	0.241	1267 9	245.97	0.000	0.523	422.0
Dec 11	3.265	0.210	555.7	114.58	0.000	0.572	333.3	6.402	0.241	1216.3	236.99	0.000	0.502	417.6
Dec 21	3.055	0.210	539.6	109.72	0.000	0.566	328.7	6.161	0.248	1169 8	229.97	0 000	0.483	411.1
Jan 1	2.845	0.210	548.9	111.27	0.000	0.589	323.6	5.913	0.336	1266.8	250.84	0.000	0 527	403.5
Jan 11	2.636	0.210	540.5	109.32	0.000	0.593	318.6	5 577	0.343	1256.3	248.32	0.000	0.534	396.1
Jan 21	2.426	0.210	576.2	116.34	0 000	0.650	313.0	5.234	0.343	1226.1	242.08	0.000	0.535	388.4
Feb 1	2.216	0.237	663.1	133.76	0.000	0.772	306.5	4.891	0.511	1513.5	298.16	0.000	0.685	379.1
Feb 11	1.979	0.237	696.5	140.57	0.000	0.843	299.2	4.380	0.511	1489.8	292.25	0.000	0.725	365.1
Feb 21	1.742	0.233	707.7	142.81	0.000	0.894	291.6	3.869	0.511	1451.7	284.00	0.000	0.765	348.0
Mar 1	1.509	0.237	752.9	157.40	0.059	1.000	282.6	3.358	0.489	1395.4	272.46	0.000	0.786	334.4
Mar 11	1.272	0.237	712.4	170.98	0.052	1.000	273.3	2.869	0.489	1362.3	264.21	0.000	0.839	317.6
Mar 21	1.035	0.233	668.0	160.32	0.166	1.000	263.0	2.380	0.482	1401.2	269.44	0.000	0.940	302.8
Apr 1	0.803	0.123	620.2	148.84	0.232	1.000	252.0	1.898	0.423	1359.8	260.61	0.007	1.000	287.6
Apr 11	0.679	0.123	588.6	141.27	0.357	1.000	244.7	1.475	0.409	1216.5	233.67	0.083	1.000	270.1
Apr 21	0.556	0.169	553.8	132.92	0.525	1.000	236.6	1.066	0.482	1075.1	258.03	0.101	1.000	252.8
May 1	0.388	-0.502	528.6	115.90	0.027	1.000	230.7	0.584	0.255	929.0	222.97	0.160	1.000	235.1
May 11	0.889	-0.274	635.7	152.56	0.281	1.000	255.6	0.328	0.328	838.6	201.25	0.607	1.000	224.1
May 21	1.163	-0.274	683.9	164.13	0.302	1.000	266.7	-0.000	-0.	721.9	173.25	0.911	1.000	210.0
Jun 1	1.436	-0.456	735.8	176.60	0.107	1.000	278.7	-0.000	-1.095	723.3	173.60	0.855	1.000	210.2
Jun 11	1.892	-0.502	801.8	192.44	0.059	1.000	293.9	1.095	-1.095	1049.0	251.75	1.486	1.000	249.6
Jun 21	2.394	-0.502	865.5	207.73	0.068	1.000	308.0	2.190	-1.095	1385.8	332.60	1.707	1.000	290.7
Jul 1	2.896	-0.456	916.2	219.89	0.118	1.000	319.7	3.285	-1.460	1680.7	403.37	2.271	1.000	323.9
Jul 11	3.352	-0.456	962.7	231.05	0.006	1.000	331.1	4.745	-1.460	2072.0	497.29	2.390	1.000	366.9
Jul 21	3.808	-0.410	993.8	238.51	0.015	1.000	339.5	6.205	-1.095	2396.0	575.04	2.823	1.000	402.2
Aug 1	4.218	-0.342	1024.6	213.79	0.133	1.000	347 1	7.300	-0.	2422.6	581.41	4.263	1.000	422.5
Aug 11	4.560	-0.	1041.4	249.94	0.202	1.000	351.0	7.300	-0.	2422.6	581.41	3.565	1.000	422.4
Aug 21	4.560	-0.	1051.7	252.41	0.038	1.000	352.7	7.300	-0.	2422.6	581.41	2.542	1.000	423.0
Sep 1	4.560	-0.	1060.8	219.79	0.000	1.000	354.3	7.300	-0.	2422.6	581.41	1.468	1.000	424.8
Sep 11	4.560	-0.	877.3	177.37	0.000	0.822	355.6	7.300	-0.	2422.6	581.41	0.620	1.000	426.9
Sep 21	4.560	0.068	824.0	166.32	0.000	0.771	355.9	7.300	-0.	2422.6	500.94	0.246	1.000	429.1

Mangla Drawdown 1079 Level Tarbela Release Pattern October 8, 1965

ANNEX 6
Appendix I

Table 3

Consultants' Computer Simulation of Reservoir Operation - Mangla and Tarbela, 1985 - Critical Year Flows

	MANGLA (8 UNITS)							TARBELA (12 UNITS)						
	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (Mw)	Max Aval Energy (Kwh x 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (Mw)	Max Aval Energy (Kwh x 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)
Oct 1	4.560	0.169	687.2	138.14	0.000	0.640	356.8	7.300	-0.	2422.6	502 25	0.120	1.000	429.5
Oct 11	4.391	0.150	698.4	142.50	0.000	0.660	353.8	7.300	-0.	1888.2	364.44	0.000	0.779	431.4
Oct 21	4.241	0.182	686.9	142.34	0.000	0.659	351.1	7.300	0.073	1515.7	292.47	0.000	0.626	432.2
Nov 1	4.058	0.196	680.7	142.14	0.000	0.663	347.7	7.227	0.146	1377.5	265.87	0.000	0.569	431.4
Nov 11	3.862	0.196	613.2	128.45	0.000	0.605	344.5	7.081	0.219	1465.8	283.18	0.000	0.605	428.7
Nov 21	3.666	0.192	553.8	115.99	0.000	0.553	341.3	6.862	0.219	1390.7	269.16	0.000	0.574	425.3
Dec 1	3.475	0.210	572.4	119.35	0.000	0.580	337.7	6.643	0.241	1359.8	263.83	0.000	0.561	421.8
Dec 11	3.265	0.210	537.9	110.96	0.000	0.554	333.5	6.402	0.241	1265.4	246.59	0.000	0.522	417.4
Dec 21	3.055	0.210	516.2	104.98	0.000	0.541	328.8	6.161	0.248	1180.9	232.17	0.000	0.487	411.0
Jan 1	2.845	0.210	488.4	99.04	0.000	0.523	324.0	5.913	0.336	1285.1	254.46	0.000	0.535	403.4
Jan 11	2.636	0.210	475.3	96.15	0.000	0.520	319.0	5.577	0.343	1249.0	246.89	0.000	0.531	396.1
Jan 21	2.426	0.210	464.8	93.86	0.000	0.522	313.8	5.234	0.343	1179.6	232.91	0.000	0.514	388.5
Feb 1	2.216	0.237	502.2	101.31	0.000	0.581	307.7	4.891	0.511	1436.2	282.95	0.000	0.650	379.3
Feb 11	1.979	0.237	472.6	95.35	0.000	0.567	300.9	4.380	0.511	1380.5	270.83	0.000	0.671	365.4
Feb 21	1.742	0.233	452.9	91.46	0.000	0.566	293.6	3.869	0.511	1324.2	259.07	0.000	0.697	348.3
Mar 1	1.509	0.237	536.3	107.92	0.000	0.702	285 2	3 358	0.489	1254.2	244.91	0.000	0.705	334.7
Mar 11	1.272	0.237	655.4	131.28	0.000	0.908	275.4	2.869	0.489	1242.7	241.07	0.000	0.764	317.9
Mar 21	1.035	0.233	678.3	143.64	0.001	1.000	265.4	2.380	0.482	1221.4	234.95	0.000	0.817	303.3
Apr 1	0.803	0.123	629.1	150.98	0.022	1.000	254.1	1.898	0.423	1184.7	226.38	0.000	0.868	288.2
Apr 11	0.679	0.123	599.8	143.96	0.092	1.000	247.3	1.475	0.409	1150.0	218.60	0.000	0.942	270.7
Apr 21	0.556	0.169	574.7	137.92	0.032	1.000	241.5	1.066	0.482	1084.6	210.15	0.059	1.000	253.9
May 1	0.388	-0.274	504.1	98.62	0.000	0.945	231.9	0.584	0.255	898.6	169.47	0.000	0.952	236.9
May 11	0.661	-0.274	584.5	115.34	0.000	0.966	248.5	0.328	0.328	858.6	173.31	0.139	1.000	226.6
May 21	0.935	-0.274	642.0	127.65	0.000	0.970	261.7	-0.000	-0.	750.5	156.92	0.099	1.000	213.5
Jun 1	1.208	-0.365	672.7	134.58	0.000	0.947	272.8	-0.000	-0.	729.6	175.11	0.626	1.000	210.9
Jun 11	1.573	-0.502	691.0	139.11	0.000	0.899	286.1	-0.000	-1.533	728.3	174.80	0.672	1,000	210.8
Jun 21	2.075	-0.365	715.0	144.24	0.000	0.853	302.0	1.533	-1.752	1204.6	289.10	0.952	1.000	268.6
Jul 1	2.440	-0.456	714.6	144.26	0.000	0.808	312.3	3.285	-1.460	1705.5	409.32	0.982	1.000	326.7
Jul 11	2.896	-0.456	785.3	159.16	0.000	0.844	323.2	4.745	-1.460	2092.0	502.07	1.435	1.000	368.5
Jul 21	3.352	-0.319	767.3	158.45	0.000	0.789	333.8	6.205	-1.095	2405.9	577.43	1.569	1.000	403.9
Aug 1	3.671	-0.365	900.4	188.17	0.000	0.907	339.1	7.300	-0.	2422.6	581.41	3.237	1.000	422.5
Aug 11	4.036	-0.456	1012.4	211.16	0.095	1.000	344.1	7.300	-0.	2422.6	581.41	4.399	1.000	422.6
Aug 21	4.492	-0.068	1032.8	247.88	0.288	1.000	349.1	7.300	-0.	2422.6	581.41	4.198	1.000	422.5
Sep 1	4.560	-0.	1054.5	219.01	0.113	1.000	353.2	7.300	-0.	2422.6	581.41	3.237	1.000	422.5
Sep 11	4.560	-0.	908.7	183.90	0.000	0.852	355.4	7.300	-0.	2422.6	581.41	1.604	1.000	424.5
Sep 21	4.560	0.068	855.6	172.87	0.000	0.801	355.7	7.300	-0.	2422.6	581.41	0.129	1.000	428.5

Mangla Drawdown 1075' Level Tarbela Release Pattern October 8, 1965

content at the beginning of each ten-day period in order to derive the reservoir content at the end of each period. The water elevation corresponding to the content is read on the reservoir capacity curves given in the consultants' reports.

The gross head on the turbines is calculated as the difference between the reservoir level and the tailwater level. Tailwater level is a function of discharge, so that to calculate it exactly would involve a lengthy set of calculations which could not be handled manually. Information available to the Bank Group at the time it was preparing the reservoir simulations indicated that the maximum oscillation on the tailraces at Mangla and Tarbela was about five feet. A change of two feet in tailwater level corresponds to a change of only about 1.25 mw in the output of each unit at both dams. Therefore it appeared that use of an average value for the tailwater level would not involve significant error. Available information indicated that the average tailwater level at Tarbela would be 1115 feet and at Mangla 835 feet. These are the assumed tailwater levels which underlie the figures presented later in this appendix.

Subsequent to completion of work on the reservoir simulation, information became available to the Bank Group indicating that the range of tailwater levels at Tarbela is now estimated at 1100-1115 feet and at Mangla at 835.5-846 feet. The wider ranges implied by these figures mean that the error involved in the Bank Group's approach would be somewhat greater than was believed. The fact that the averages of maximum and minimum tailwater levels at each of the two dams are apparently different from those assumed in the Bank Group's calculations also introduces some -- partly compensating -- error. The Bank Group's assumption of an average tailwater level of 1115 feet at Tarbela (where this is now expected to be the maximum tailwater level) imparts a downward bias to the mw-output figures given below for Tarbela. The assumption of an average tailwater level of 835 feet at Mangla (which is now apparently expected to be the minimum level there) means that the mw-output figures presented below for Mangla are slightly exaggerated. At minimum reservoir levels, for instance, the output of one Tarbela unit could be up to about 7 mw greater than calculated below (i.e. with tailwater level of 1100 instead of 1115), while the output of one unit at Mangla might be up to 5 mw smaller than calculated below (i.e. with tailwater level of 846 instead of 835). In actual fact, the differences will probably not be as great as these figures imply because tailwater level in the period of minimum reservoir level is likely to be intermediate between maximum and minimum.

Once the gross head had been derived on the assumption of average tailwater levels, the net head is obtained by deducting from it a constant loss figure of five feet. The output and discharge of each unit are then read against the net head on turbine characteristic curves supplied to the Bank Group by the consultants in June 1965. As pointed out in the discussion of the computer program two sets of turbine characteristics are given: peak and optimum. In this manual

simulation, the 'peak' one has been adopted because of its higher mw output, even though this procedure is conducive to a slightly lower generation of energy during water-short periods.

In the manual simulation the capacity of the units has been assumed independent of the amount of water available and related only to the net head. This means that the maximum discharge is limited only by the turbine peaking capacity and is not tied to the average discharge, as is the case with the consultants' computer program. In water-short periods the distribution of the releases over a day may therefore be rather uneven, with a few hours at full capacity, and the remaining hours at very low capacity. The consequence of having the capacity independent from the flows is that there is no difference between mean-year and critical-year capacities.

Such departure from the consultants' assumptions was deemed justified, in the case of Tarbela, because there is no canal in the vicinity of the dam outlets which could suffer from surges in the water levels; and, in the case of Mangla, because existing structures (Bong escape, Jhelum River Channel and Rasul Barrage) could satisfactorily absorb sudden water level variations giving protection to the irrigation works. In order, however, to avoid any variations in the supply of the Upper Jhelum Canal, it was assumed that the outflow from the Mangla Reservoir should be distinguished into two parts: (i) a constant release to meet the requirements of the canal; this discharge is sufficient to keep constantly in operation two or three turbines, depending on the time of the year; (ii) a release which can be adjusted to the power requirements and could produce sharp variations in discharge, using the remaining turbines. The first part, or base, was called Mangla A; the second part, or peak, Mangla B.

Relaxation of the restriction on peaking assumed by the consultants does not necessarily mean that the units will be dispatched by the power simulation model in such a way as to make full use of their peaking capacity. It may happen, especially in the winter when flows are low, that there is more hydro peaking capacity available than can be absorbed by the system. Then the power simulation model will tend to dispatch only some of the hydro units, effectively diverting all available flows through these units (and leaving the others idle) so that the flows are converted into energy at an instantaneous load lower than the peak attainable if the units were used for maximum peaking capacity. However relaxation of the restriction on peaking has the advantage of leaving the computer with more flexibility, within the framework of the power simulation model, regarding the use that might be made of the energy and capacity available at the hydro stations under any particular set of conditions: it can dispatch all units at the peak, a few units on base load or it can use them in some intermediate position. The subdivision of the Mangla units into two groups is also advantageous for the purposes of the system dispatch since it corresponds more closely to actual operation and makes possible greater use of available hydro energy than would be possible, within the framework of the power system simulation model, if the Mangla units were treated as a single block.

The product of the peak capability in a period and the duration of the period gives the maximum amount of energy which could be generated during that period. If the outflows -- sum of the inflow and reservoir release -- are high enough to sustain full capacity operation throughout the period, the energy produced will be equal to this maximum. In the case of lower flows, the maximum energy figure has to be reduced by a coefficient equal to the ratio between the available outflow and the maximum volume of water which could be discharged through the turbines during the period in question. This coefficient is called 'operation factor'; it is different from the consultants' 'reduction factor' inasmuch as it reflects the shortage of water in the energy which can be produced rather than in the capability of the units. Nevertheless, there is a direct relationship between these two factors. In the case of Tarbela the reduction factor (r.f.) is equal to one for values of the operation factor (o.f.) between 1 and 1/1.3, and 1.3 x o.f. for values of o.f. less than 1/1.3. No such relationship can be given in the case of Mangla, because of the distinction into two parts, Mangla A and Mangla B, each having its own operation factor (Mangla A has, by definition, an operation factor of 1, as it is base). In the derivation of energy-output and peak capabilities of the hydro units at Mangla and Tarbela by manual simulation no allowance has been made for generation losses and station uses; in other words the resultant figures are gross rather than net.

Mangla Data

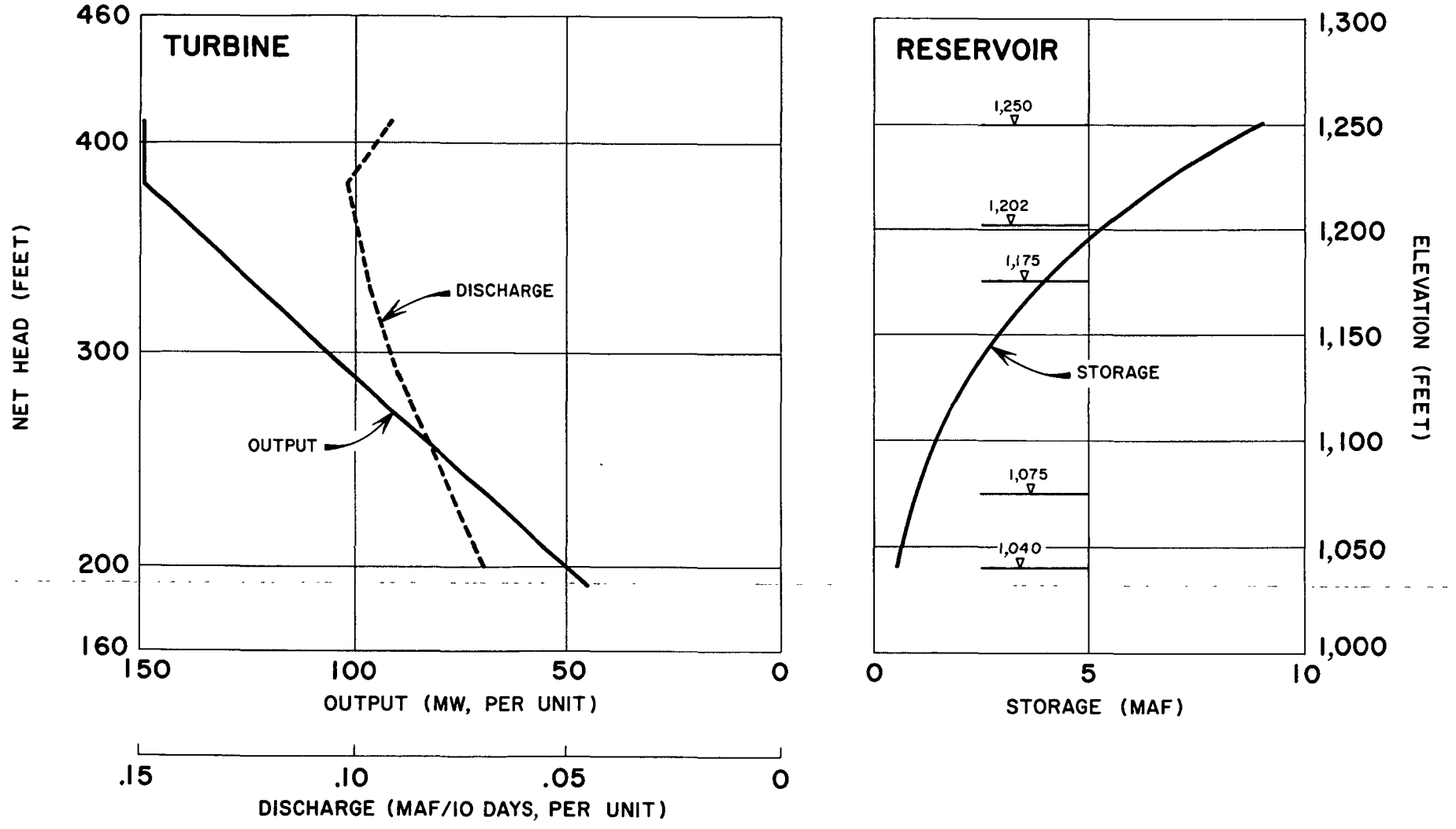
Table No. 4 shows a typical manual simulation calculation. It refers to Mangla with drawdown level of 1040, with a live storage of 4.90 MAF, in a mean-year flow condition. Column No. 1 gives the date at which each period starts. Column No. 2 is the natural flow of the river during the ten-day period following the given date. Column No. 3 gives the release (or storage if the figure is negative) as a percentage of the live storage, during the interval considered. Column No. 4 is the value of the release, in million acre-feet. The total outflow (Column No. 5) is the sum of the inflow and the release (Columns 2 and 4). The total gross amount of water contained in the reservoir at the given date is shown in Column 6; it is the difference between the reservoir content at the previous date, and the release taking place during the elapsed ten-day period. The reservoir elevation corresponding to that content is read on Figure 2 and recorded in Column 7. Column 8 gives the net head on the turbines, and is the difference between the reservoir elevation or gross head and 840 feet -- this last figure being the elevation of the tailwater level (assumed to be constant), increased by an allowance for hydraulic losses. Columns 9 and 10 show MAF capacity of one unit in mw, given the net head in the previous column, and the corresponding maximum discharge of one unit in MAF per ten-day period; these values are read in Figure 2 against the reservoir level. The maximum energy which can be generated by one unit is shown in million kwh in Column 11; the energy is calculated by multiplying the capacity (mw) by the number of hours in a ten-day period (240). Column 12 indicates the water requirements of the Upper

Jhelum Canal, and Column 13 shows the minimum number of units which would have to be operated continuously in order to discharge sufficient water to satisfy these requirements. Under the heading 'Mangla A' are given the capacity (Column 14), discharge (Column 15) and energy (Column 16) figures corresponding to the number of units shown in Column 13. These figures are calculated by multiplying respectively the figures given in Columns 9, 10 and 11 with the number of units of Column 13. Columns 17, 18, 19 and 20 show respectively the number of remaining units, and the capacity, discharge and energy produced by these remaining units (Mangla B). Whereas the capacity figure is a multiple of the capacity of one unit, the discharge is the difference between the total outflow (Column 5), and the discharge of the Mangla A units (Column 15). The ratio between this discharge (Column 19) and the maximum amount of water which could be passed through the turbines (calculated as product of the discharge of one unit -- Column 10 -- and the number of units of Mangla B) is given in Column 21 as "operation factor" (o.f.). The energy figure (Column 20) is derived as product of the capacity (Column 18), the number of hours in a ten-day period and the operation factor (Column 21). Columns 22 and 23 show the total capacity and energy available from Mangla, with eight units; Column 22 is the sum of Columns 14 and 18, and Column 23 is the sum of Columns 16 and 21.

The consultants studied the operation of Mangla Reservoir with drawdown levels of 1040 feet and 1075 feet and with a number of different release patterns. They also considered High Mangla with different Full Supply Levels and different Minimum Reservoir Levels. Table 5 shows some of the different release patterns considered by the consultants. The first one listed is the release pattern adopted by the power consultant for planning purposes; it is slightly more favorable to power insofar as it includes lower releases in October and November and higher releases at the end of the rabi period than the other release patterns. The second column shows the release pattern used in the consultants' computer studies on power which came closest to the release pattern finally recommended by the irrigation consultant. This 'final' release pattern, which underlies most of the Bank Group's studies of power development at Mangla, is shown on the right-hand side of the table.

Table 6 compares three different simulations of the operation of Mangla Reservoir assuming a drawdown level of 1040 feet. The first four columns are derived from the IACA simulation of reservoir operation and relate to the case of Mangla operated according to the release pattern used by Stone & Webster for most of their studies. The second block of four columns, which are also derived from the IACA computer studies, show the operation of Mangla according to the second release pattern shown below in Table 5. The last two columns in the table show the results of the Bank Group's manual simulation on the basis of the irrigation consultant's final release pattern. Where the figures in this table are derived from the IACA computer studies, capacities are given for critical-year conditions and energy figures are given for

MANGLA RESERVOIR AND TURBINE CHARACTERISTICS



IBRD-3436

VOLUME IV
ANNEX 6-APPENDIX I
FIGURE 2

Table 4

Mangla Reservoir Operation -- 8 Units
Mean Year Flows -- Drawdown Level 1040
Gross Storage: 5.50 MAF; Live Storage; 4.90 MAF

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
								Output 1 Unit			UJC R'ments.		MANGLA A			MANGLA B					MANGLA	A & B
Date	In-Flow (MAF)	Stor-age (%)	Re-lease (MAF)	Out-flow (MAF)	Reserv. Content (MAF)	Reserv. Elev. (Ft)	Net Head (Ft)	Cap. (mw)	Disch. (MAF)	Energy (m.kwh)	Disch. (MAF)	Units (No.)	Cap. (mw)	Disch. (MAF)	Energy (m.kwh)	Units (No.)	Cap. (mw)	Disch. (MAF)	Energy (m.kwh)	O.F (%)	Capac. (mw)	Energy (m.kwh)
Oct 1	.340	7.6	.372	.712	5.500	1202	362	138	.099	33	.237	3	414	.297	99	5	690	.415	139	84.0	1104	238
11	.278	7.7	.377	.655	5.128	1194	354	134	.099	32	.237	3	402	.297	96	5	670	.358	116	72.3	1072	212
21	.237	7.7	.377	.614	4.751	1187	347	131	.098	31	.261	3	393	.294	93	5	655	.320	103	65.3	1048	196
Nov 1	.197	5.0	.245	.442	4.374	1181	341	128	.098	31	.203	2	256	.196	62	6	768	.246	77	41.8	1024	139
11	.173	5.0	.245	.418	4.129	1176	336	125	.097	30	.203	2	250	.194	60	6	750	.224	70	38.5	1000	130
21	.159	5.0	.245	.404	3.884	1170	330	122	.097	29	.203	2	244	.194	58	6	732	.210	64	36.2	976	122
Dec 1	.155	3.3	.162	.317	3.639	1165	325	119	.096	29	.154	2	238	.192	58	6	714	.125	37	21.7	952	95
11	.165	3.3	.162	.327	3.477	1161	321	117	.095	28	.154	2	234	.190	56	6	702	.137	41	24.0	936	97
21	.157	3.4	.167	.324	3.315	1160	320	116	.095	28	.170	2	232	.190	56	6	696	.134	39	23.5	928	95
Jan 1	.168	3.3	.162	.330	3.148	1155	315	114	.094	27	.151	2	228	.188	54	6	684	.142	41	25.2	912	95
11	.168	3.3	.162	.330	2.986	1152	312	111	.093	27	.151	2	222	.186	54	6	666	.144	41	25.8	888	95
21	.201	3.4	.166	.367	2.824	1148	308	110	.093	26	.166	2	220	.186	52	6	660	.181	51	32.4	880	103
Feb 1	.245	8.0	.392	.637	2.658	1143	303	108	. 92	26	.263	3	324	.276	78	5	540	.361	102	78.5	864	180
11	.281	8.0	.392	.673	2.266	1130	290	101	.089	24	.263	3	303	.267	72	5	505	.406	111	91.4	808	183
21	.307	8.0	.392	.699	1.874	1118	278	94	.087	23	.210	3	282	.261	69	5	470	.438	113	100.0	752	182
Mar 1	.438	6.0	.294	.732	1.482	1100	260	84	.083	20	.237	3	252	.249	60	5	420	.483	101	100.0	672	161
11	.510	6.0	.294	.804	1.188	1082	242	73	.079	18	.237	3	219	.237	54	5	365	.567	88	100.0	584	142
21	.610	6.0	.294	.904	.894	1065	225	64	.076	15	.261	3	192	.228	45	5	320	.676	77	100.0	512	122
Apr 1	.765	0	0	.765	.600	1040	200	50	.070	12	.245	3	150	.210	36	5	250	.555	60	100.0	400	96
11	.878	0	0	.878	.600	1040	200	50	.070	12	.245	3	150	.210	36	5	250	.668	60	100.0	400	96
21	.986	0	0	.986	.600	1040	200	50	.070	12	.245	3	150	.210	36	5	250	.776	60	100.0	400	96
May 1	1.110	-8.0	-.392	.718	.600	1040	200	50	.070	12	.236	3	150	.210	36	5	250	.508	60	100.0	400	96
11	1.220	-8.0	-.392	.828	.992	1071	231	67	.077	16	.236	3	201	.231	48	5	335	.597	80	100.0	536	128
21	1.260	-8.0	-.392	.868	1.384	1098	258	83	.083	20	.260	3	249	.249	60	5	415	.619	100	100.0	664	160
Jun 1	1.270	-12.0	-.588	.682	1.776	1112	272	91	.085	22	.116	2	182	.170	44	6	546	.512	131	100.0	728	175
11	1.290	-12.0	-.588	.702	2.364	1135	295	104	.090	25	.116	1	104	.090	25	7	728	.612	167	95.5	832	192
21	1.325	-12.0	-.588	.737	2.952	1151	311	112	.093	27	.116	1	112	.093	27	7	786	.644	186	98.8	896	213
Jul 1	1.345	-10.3	-.505	.840	3.540	1163	323	118	.095	28	.111	1	118	.095	28	7	826	.745	198	100.0	944	226
11	1.245	-10.3	-.505	.740	4.045	1174	334	124	.097	30	.111	1	124	.097	30	7	868	.643	197	94.6	992	227
21	1.222	-10.4	-.509	.713	4.550	1184	344	128	.097	31	.123	2	256	.194	62	6	768	.519	164	89.0	1024	226
Aug 1	1.140	-3.0	-.147	.993	5.059	1192	352	133	.098	32	.112	1	133	.098	32	7	932	.895	224	100.0	1065	256
11	1.000	-3.0	-.147	.853	5.206	1195	355	135	.099	32	.112	1	135	.099	32	7	945	.754	227	100.0	1080	259
21	.830	-3.0	-.147	.683	5.353	1197	357	136	.099	33	.123	2	272	.198	66	6	816	.485	160	81.8	1088	226
Sep 1	.670	0	0	.670	5.500	1202	362	138	.099	33	.126	2	276	.198	66	6	828	.472	158	79.6	1104	224
11	.540	0	0	.540	5.500	1202	362	138	.099	33	.126	2	276	.198	66	6	828	.342	115	57.6	1104	181
21	.436	0	0	.436	5.500	1202	362	138	.099	33	.126	2	276	.198	66	6	828	.238	80	40.1	1104	146
									TOTAL:	920				TOTAL:	1,972			TOTAL:	3,838			TOTAL: 5,810

mean-year conditions. The capacity figures, as printed out by the computer, are given under the heading 'restricted peaking'. The 'reduction factor' taken from the same printout is also shown. The ratio between the restricted peaking capacities and the reduction factor is calculated and given in the tables, under the heading "unrestricted peaking". This capacity corresponds to the maximum possible mw output of the turbines, at the given reservoir elevation, assuming no constraint is imposed on peaking. Both capacity and energy figures from the Bank Group's manual simulation are given for mean-year conditions because, as pointed out in the discussion of the manual simulation above, the capability figures would be no different even if the calculations were based on critical-year conditions.

Table 5

Mangla Release Patterns

Expressed as Percentage of Usable Storage
(Positive Figures Show Releases -- Negative Figures Show Storage)

	Stone & Webster Base		IACA Computer Run No. 3		Irrigation Consultant Final
Month	Mean	Critical	Mean	Critical	Mean & Critical
October	+12		+20		+23
November	+14		+18		+15
December	+14		+15		+10
January	+15		+11		+10
February	+17		+18		+24
March	+17		+18		+18
April	+10		0		0
May	-25.0	-20.0	-23	-18	-24
June	-35.0	-30.0	-32	-27	-36
July	-32.0	-30.0	-29	-27	-31
August	- 8.0	-20.0	-16	-28	- 9
September	0		0		0

A comparison of the computer simulation and the manual simulation shows that the two methods of calculation produce very similar results. For purposes of comparison, the "unrestricted peaking" capacity figures are used for the computer simulation, in order to eliminate the distortion introduced by the restriction. The capacity figures calculated manually are systematically higher by two or three percentage points. This difference, which is generally very small is due to the facts that different assumptions were made about tailwater levels (see page 33), the turbine characteristics were read to give systematically higher outputs in the manual simulation than in the computer simulation and also that the results of the manual simulation did not have generation losses netted out.

More significant deviations between the two sets of figures on the right occur in December-February and in the filling period, and these differences are largely the result of the different release patterns assumed. The manual simulation figures show lower energy production in December and increasingly higher capabilities than the figures derived from the computer -- because the December releases envisaged in the final IACA release pattern are significantly below those assumed in the release pattern underlying the computer simulation of reservoir operation. By the beginning of March, at which point both release patterns indicate that 18 percent of live storage would remain in the reservoir, the differences in capabilities are back to the relatively small proportions resulting from different assumptions regarding turbine characteristics. The filling of the reservoir takes place more slowly in the release pattern underlying the figures derived from the computer (i.e. the release pattern for Computer Run No. 3 in Table 5 above) than in the IACA final release pattern, and so the capacity given by the print-out lags continuously behind the manually calculated capacity during the filling period. The energy figures from the manual simulation are slightly higher than those from the computer simulation overall and also in most of the individual months: larger differences occur in December and February mainly as a result of the difference in amounts of water released in those months with the different release patterns.

Comparison of the two blocks of figures on the left-hand side of Table 6, both derived from the computer simulation of reservoir operation gives an indication of the effect of altering the release pattern. The irrigation consultant finally concluded in favor of higher releases in October and November than had been assumed by the power consultant and this has the effect of increasing the availability of energy at that time; but the higher releases in the early part of the rabi season reduce the reservoir content and therefore the head on the turbines more quickly, so that from December through April the capabilities are almost always somewhat less with the irrigation consultant's release pattern than with the power consultant's release pattern. However, by May 1st, the reservoir is, under both release patterns, fully drawn down to 1040 feet and the available capability is the same, at 380 mw. It is noteworthy that the total amount of energy produced in the mean year is much the same under both release patterns, though slightly higher with the release pattern which retains more water in the reservoir to a later period of the year.

The following tables give more details of some of the alternative reservoir operations studied by the Bank. Table 7 summarizes a few of the main alternatives considered. The first column refers to the basic case of Low Mangla drawn down to 1040 feet which was presented in full in Table 4 above. The second column covers the case of Low Mangla drawn to 1075 feet. Both of these cases were studied to a considerable extent with the aid of the power system simulation model; the figures used for this purpose are presented in Table 8. 1/ The last three

1/ It will be noted that the energy figures presented in Table 8 deviate slightly from those presented in Table 7 and Table 4. The deviations, which result from slight differences in underlying assumptions regarding the distribution of mean-year flows among ten-day periods, are insignificant.

TABLE 6

COMPARISON OF MANGLA RESERVOIR OPERATIONS
Critical Year Capacity - Mean Year Energy -- 8 Units
Maximum Reservoir Elevation: 1202', Drawdown Level 1040'

	COMPUTER PROGRAM								MANUAL SIMULATION	
	Stone and Webster Release Pattern				Computer Run No. 3 Release Pattern					
	CAPACITY			ENERGY	CAPACITY			ENERGY	CAPACITY	ENERGY
DATE	Restricted Peaking (mw)	Reduction Factor	Unrestricted Peaking (mw)	(Million kwh)	Restricted Peaking (mw)	Reduction Factor	Unrestricted Peaking (mw)	(Million kwh)	(mw)	(Million kwh)
Oct. 1	721	.674	1070	150	983	.927	1068	205	1104	238
11	728	.692	1052	147	896	.868	1035	185	1072	212
21	726	.701	1035	146	853	.843	1010	174	1048	196
Nov. 1	720	.706	1020	136	773	.781	992	147	1024	139
11	652	.648	1006	127	745	.765	974	144	1000	130
21	592	.598	990	119	686	.721	953	135	976	122
Dec. 1	612	.628	974	121	594	.642	925	115	952	95
11	579	.604	958	121	556	.616	902	116	936	97
21	552	.590	935	117	529	.603	876	111	928	95
Jan. 1	523	.572	914	118	403	.472	855	93	912	95
11	508	.572	888	116	391	.470	832	91	888	95
21	496	.575	863	122	414	.512	809	105	880	103
Feb. 1	538	.648	830	140	536	.690	778	138	864	180
11	506	.637	794	146	501	.681	736	142	808	183
21	482	.638	755	146	480	.696	690	142	752	182
Mar. 1	557	.784	710	168	575	.911	630	149	672	161
11	660	1.000	660	156	558	1.000	558	132	584	142
21	601	1.000	601	142	474	1.000	474	111	512	122
Apr. 1	536	1.000	536	127	378	1.000	378	89	400	96
11	491	1.000	491	115	375	1.000	375	87	400	96
21	445	1.000	445	102	380	1.000	380	86	400	96
May 1	381	1.000	381	90	381	1.000	381	90	400	96
11	486	1.000	486	129	486	1.000	486	129	536	128
21	567	1.000	567	144	567	1.000	567	144	664	160
Jun. 1	607	.963	630	159	607	.963	630	630	728	159
11	625	.892	700	178	625	.892	700	178	832	178
21	662	.849	780	195	662	.849	780	195	896	213
Jul. 1	659	.792	832	209	659	.792	833	209	944	226
11	730	.823	886	191	730	.823	886	191	992	227
21	729	.779	936	232	729	.779	936	232	1024	226
Aug. 1	861	.895	962	207	861	.895	962	207	1064	256
11	983	1.000	983	214	983	1.000	983	214	1080	259
21	1019	1.000	1019	218	1019	1.000	1019	218	1088	226
Sep. 1	1052	1.000	1052	220	1052	1.000	1052	220	1104	224
11	906	.851	1065	177	906	.851	1065	177	1104	181
21	866	.812	1066	169	866	.812	1070	169	1104	146
			TOTAL	5514			TOTAL	5429	TOTAL	5810

IACA Computer Printout: 9/27/65 - Run 1 Mangla
Full Drawdown 1974 Conditions.

IACA Computer Printout: 12/16/65 - Run 3 Mangla
Full Drawdown 1974 Conditions.

columns of Table 7 indicate some of the cases of High Mangla which were considered. The first of these columns indicates that raising the maximum reservoir elevation at Mangla from 1202 to 1250 results in an increase of about 500 million kwh in the generation of energy, if the drawdown level is kept at 1075 feet. But limiting the drawdown level to 1175 feet (see the second High Mangla column) increases both the firm capacity (by about 450 mw) and the annual energy generated (by about 1,300 million kwh). The 100 feet of difference in drawdown level (from 1075 feet to 1175 feet) results in a loss of usable storage of about 3.1 MAF. The last column in Table 7 covers the case of Mangla raised to provide additional irrigation supplies. It is the case used in the study of the postponement of Tarbela and it is discussed in greater detail in Annex 7. The so-called 'Special' release pattern used represents a combination of the release patterns finally recommended by the irrigation consultant for Mangla and Tarbela Reservoirs. The 4.8 MAF of live storage corresponding to the live storage capacity of Low Mangla by 1975 is released according to the consultant's Mangla release pattern, while the additional 3.5 MAF of live storage added by the raising of Mangla is assumed to be released according to the irrigation consultant's Tarbela release pattern. The manual simulation of High Mangla Reservoir operation under these assumptions is presented in full in Table 9.

Table 7

Mangla Reservoir -- Alternative Operations
(Bank Group's Manual Simulation)

		Low Mangla		High Mangla		
Release Pattern		Final	Final	Final	Final	Special
Full Supply Level	(feet)	1202	1202	1250	1250	1250
Drawdown Level	(feet)	1040	1075	1075	1175	1040
Initial Live Storage	(MAF)	4.90	4.50	8.00	4.90	8.30
Firm Capacity		400	544	544	992	480
		------	(April 1 --	May 10)	------	(May 1-10)
Annual Energy	(mln. kwh)	5810	6033	6505	779	6272
Number of Units		8	8	8	8	8

Tarbela Data

Table 10 gives full details of a manual simulation of the operation of Tarbela Reservoir with drawdown level of 1332 feet and under mean-year flow conditions. With this drawdown level the live storage in the first year of operation (i.e. without siltation) is about 8.60 MAF. Columns 1 to 6 in this table are calculated in the manner described above with reference to Mangla in the discussion accompanying Table 4. Column 7, the reservoir elevation, is read on Figure 3 against the reservoir content; Column 8 indicates the net head on the turbines and is derived by subtracting from the figure

Table 8

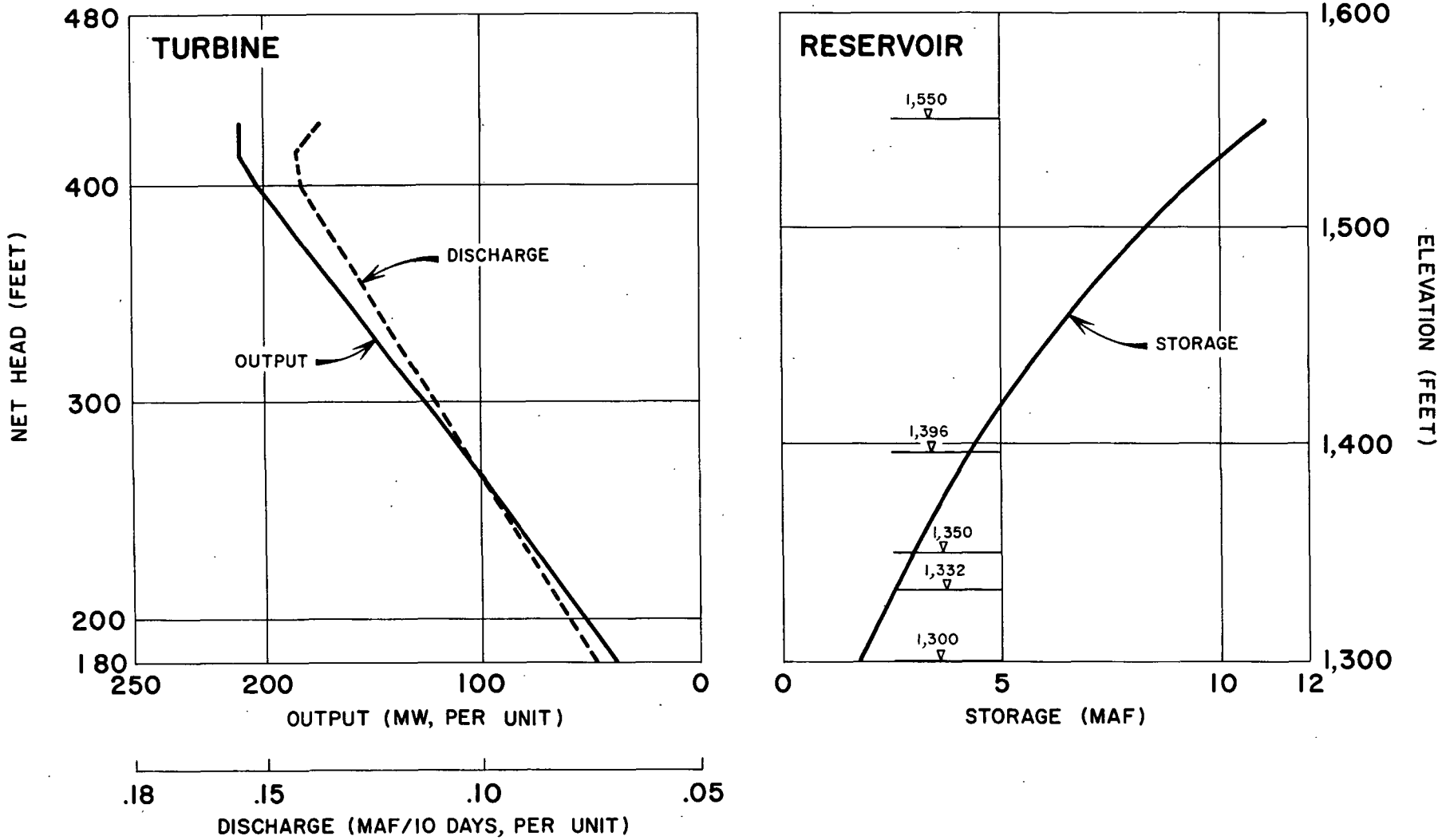
Low Mangla: Data Used in Power System Simulation Studies
(FSL: 1202', Mean Year, 8 units)

	Drawdown Level 1040'				Drawdown Level 1075'			
	Mangla A		Mangla B		Mangla A		Mangla B	
	Capability (mw)	Energy (m. kwh)	Capability (mw)	Energy (m. kwh)	Capability (mw)	Energy (m. kwh)	Capability (mw)	Energy (m. kwh)
Jan.	217	156	660	148	227	164	684	124
Feb.	279	201	465	307	315	231	530	303
Mar.	187	135	311	224	256	186	430	310
Apr.	150	108	250	180	204	144	340	245
May	241	173	401	288	244	174	408	292
June	220	158	637	432	211	152	636	458
July	254	183	773	420	248	178	744	528
Aug.	270	194	820	554	270	192	810	551
Sept.	273	197	831	353	276	198	828	346
Oct.	393	283	655	352	269	194	807	424
Nov.	241	173	735	209	251	182	753	192
Dec.	229	165	699	120	238	170	714	105
		2126		3587		2165		3878

Minimum Capability: 400 mw (Apr. 1 - May 10) 544 mw (Apr. 1 - May 10)

Total Energy: 5713 million kwh 6043 million kwh

TARBELA RESERVOIR AND TURBINE CHARACTERISTICS



IBRD-3437

VOLUME IV
ANNEX 6-APPENDIX 1
FIGURE 3

Table 9

High Mangla Reservoir Operation -- 8 Units
Mean Year Flows -- Drawdown Level 1040
Gross Storage: 8.9 MAF; Live Storage: 8.3 MAF

1	2	3	4	5	6	9	10	11	12	13	14	15	16	17	18	19		20
						Output 1 Unit			UJC R'ments		MANGLA - A			MANGLA		B		
Date	In-Flow (MAF)	Storage (%)	Release (MAF)	Out-flow (MAF)	Reserv. Content (MAF)	Cap. (mw)	Disch. (MAF)	Energy (mln.kwh.)	Disch. (MAF)	Units (No.)	Cap. (mw)	Disch. (MAF)	Energy (mln.kwh.)	Units (No.)	Cap. (mw)	Disch. (MAF)	O.F. (%)	Energy (mln.kwh.)
Oct 1	.340	4.2	.374	.714	8.900	148	.091	36	.237	3		.273				.441	96.9	174
11	.278	4.2	.374	.652	8.526	148	.093	36	.237	3	444	.279	324	5	740	.373	80.2	144
21	.237	4.2	.374	.611	8.152	148	.095	36	.261	3		.285				.326	68.6	123
Nov 1	.197	3.7	.329	.526	7.778	148	.096	36	.203	2		.192				.334	58.0	125
11	.173	3.7	.329	.502	7.449	148	.098	36	.203	2	296	.196	216	6	888	.306	52.0	112
21	.159	3.8	.338	.497	7.120	148	.099	36	.203	2		.198				.299	50.3	109
Dec 1	.155	3.1	.276	.431	6.782	148	.100	36	.154	2		.200				.231	38.5	83
11	.165	3.1	.276	.441	6.506	147	.101	35	.154	2	294	.202	212	6	882	.239	39.4	83
21	.157	3.1	.276	.433	6.230	146	.101	35	.170	2		.202				.231	38.1	80
Jan 1	.168	4.5	.401	.569	5.954	144	.101	35	.151	2		.202				.367	60.5	127
11	.168	4.5	.401	.569	5.553	142	.100	34	.151	2	282	.200	204	6	846	.369	61.5	125
21	.201	4.6	.409	.610	5.152	137	.099	33	.166	2		.198				.412	69.3	137
Feb 1	.245	7.7	.685	.930	4.743	133	.098	32	.263	3		.294				.636	100.0	160
11	.281	7.7	.685	.966	4.058	126	.097	30	.263	3	377	.291	270	5	630	.675	100.0	150
21	.307	7.7	.685	.992	3.373	118	.095	28	.210	3		.285				.707	100.0	140
Mar 1	.438	5.9	.525	.963	2.688	108	.092	26	.237	3		.276				.687	100.0	130
11	.510	5.8	.516	1.026	2.163	98	.088	24	.237	3	294	.264	213	5	490	.762	100.0	120
21	.610	5.8	.516	1.126	1.647	87	.084	21	.261	3		.252				.874	100.0	105
Apr 1	.765	1.3	.116	.881	1.131	72	.079	17	.245	3		.237				.644	100.0	85
11	.878	1.3	.116	.994	1.015	70	.078	17	.245	3	208	.234	150	5	345	.760	100.0	85
21	.986	1.3	.116	1.102	.899	66	.076	16	.245	3		.228				.874	100.0	80
May 1	1.110	-3.5	-.312	.798	.783	60	.074	14	.236	3		.222				.576	100.0	70
11	1.220	-3.5	-.312	.908	1.095	71	.078	17	.236	3	215	.234	153	5	355	.674	100.0	85
21	1.260	-3.4	-.303	.957	1.407	84	.083	20	.260	3		.249				.708	100.0	100
Jun 1	1.270	-10.3	-.919	.351	1.710	89	.085	21	.116	2		.170				.181	35.5	45
11	1.290	-10.6	-.939	.351	2.629	106	.091	25	.116	2	210	.182	150	6	630	.169	31.0	47
21	1.325	-11.0	-.979	.346	3.568	120	.096	29	.116	2		.192				.154	26.7	46
Jul 1	1.345	-11.0	-.979	.366	4.547	131	.098	31	.111	2		.196				.170	28.9	54
11	1.245	-10.4	-.929	.316	5.526	142	.100	34	.111	2	280	.200	202	6	840	.116	19.3	39
21	1.222	-9.9	-.879	.343	6.455	148	.102	36	.123	2		.204				.139	22.7	49
Aug 1	1.140	-6.1	-.544	.596	7.334	148	.098	36	.112	2		.196				.400	68.0	147
11	1.000	-4.9	-.436	.564	7.878	148	.096	36	.112	2	296	.192	216	6	888	.372	64.6	139
21	.830	-4.9	-.436	.394	8.314	148	.093	36	.123	2		.186				.208	35.4	76
Sep 1	.670	-1.7	-.150	.520	8.750	148	.092	36	.126	2		.184				.336	60.8	131
11	.540	0	0	.540	8.900	148	.091	36	.126	2	296	.182	216	6	888	.358	65.5	141
21	.436	0	0	.436	8.900	148	.091	36	.126	2		.182				.254	46.5	100
							TOTAL:	1678				TOTAL:	2526				TOTAL:	3746

Table 10

TARBELA RESERVOIR OPERATION -- 12 UNITS
Mean Year Flows -- Drawdown Level 1332
Gross Storage = 11.10 MAF -- Live Storage: 8.60 MAF

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	INFLOW	STORAGE RELEASE		OUTFLOW	RESERV.	RESERV.	NET	OUTPUT OF 1 UNIT			OUTPUT OF TWELVE UNITS			
DATE	(MAF)	(%)	(MAF)	(MAF)	CONTENT (MAF)	ELEVATION (Ft)	HEAD (Ft.)	CAPACITY (mw)	DISCHARGE (MAF)	ENERGY (M. kwh)	CAPACITY (mw)	DISCH. (MAF)	ENERGY (M.kwh)	O.F. (%)
Oct. 1	1.087	0	0	1.087	11.100	1550	430	210	.137	50.4	2520	1.644	400	66.1
11	.840	0	0	.840	11.100	1550	430	210	.137	50.4	2520	1.644	309	51.1
21	.653	0	0	.653	11.100	1550	430	210	.137	50.4	2520	1.644	240	39.7
Nov. 1	.572	2.7	.232	.804	11.100	1550	430	210	.137	50.4	2520	1.644	295	48.8
11	.506	2.7	.232	.738	10.868	1546	426	210	.139	50.4	2520	1.668	268	44.3
21	.456	2.6	.224	.680	10.636	1541	421	210	.140	50.4	2520	1.680	245	40.5
Dec. 1	.418	3.7	.318	.736	10.412	1538	418	210	.141	50.4	2520	1.692	263	43.5
11	.400	3.7	.318	.718	10.094	1532	412	209	.143	50.2	2508	1.716	252	41.8
21	.380	3.6	.310	.690	9.776	1527	407	207	.143	49.7	2484	1.716	240	40.2
Jan. 1	.355	7.0	.602	.957	9.466	1521	401	203	.142	48.7	2436	1.704	329	56.2
11	.350	7.0	.602	.952	8.864	1512	392	196	.138	47.1	2352	1.656	325	57.4
21	.342	7.0	.602	.944	8.262	1500	380	185	.135	44.4	2220	1.620	310	58.2
Feb. 1	.347	8.7	.748	1.095	7.660	1484	364	175	.130	42.0	2100	1.560	354	70.3
11	.358	8.7	.748	1.106	6.912	1469	349	164	.126	39.3	1968	1.512	345	73.0
21	.372	8.6	.740	1.112	6.164	1450	330	148	.119	35.5	1776	1.428	332	78.0
Mar. 1	.394	6.3	.542	.936	5.424	1431	311	134	.118	32.2	1608	1.416	256	66.2
11	.416	6.3	.542	.958	4.882	1415	295	123	.108	29.5	1476	1.296	262	74.0
21	.492	6.4	.550	1.042	4.340	1398	278	108	.103	25.9	1296	1.236	262	84.4
Apr. 1	.584	3.3	.284	.868	3.790	1378	258	94	.098	22.8	1128	1.176	203	74.0
11	.645	3.3	.284	.929	3.506	1368	248	87	.095	20.9	1044	1.140	204	81.4
21	.810	3.4	.292	1.102	3.222	1357	237	78	.092	18.7	936	1.104	224	100.0
May 1	1.022	1.7	.146	1.168	2.930	1348	228	73	.089	17.5	876	1.068	210	
11	1.348	1.7	.146	1.494	2.784	1344	224	69	.088	16.6	828	1.056	199	
21	1.913	1.6	.138	2.051	2.638	1336	216	64	.084	15.3	768	1.008	184	
Jun 1	2.955	-15.0	-1.290	1.665	2.500	1332	212	61	.083	14.6	732	.996	175	
11	3.765	-15.0	-1.290	2.475	3.790	1377	257	93	.098	22.3	1116	1.176	268	
21	4.120	-15.0	-1.290	2.830	5.080	1420	300	126	.111	30.2	1512	1.332	362	
Jul 1	5.170	-18.0	-1.550	3.620	6.370	1455	335	154	.122	37.0	1848	1.466	444	
11	5.420	-18.0	-1.550	3.870	7.920	1492	372	180	.133	43.2	2160	1.596	519	
21	5.640	-19.0	-1.630	4.010	9.470	1521	401	203	.141	48.7	2436	1.696	585	
Aug 1	5.910	0	0	5.910	11.100	1550	430	210	.137	50.4	2520	1.644	605	
11	5.210	0	0	5.210	11.100	1550	430	210	.137	50.4	2520	1.644	605	
21	4.160	0	0	4.160	11.100	1550	430	210	.137	50.4	2520	1.644	605	
Sep 1	3.095	0	0	3.095	11.100	1550	430	210	.137	50.4	2520	1.644	605	
11	2.235	0	0	2.235	11.100	1550	430	210	.137	50.4	2520	1.644	605	
21	1.545	0	0	1.545	11.100	1550	430	210	.137	50.4	2520	1.644	569	94.0
									TOTAL:	1407.5		TOTAL:	12,458	

shown in Column 7 a constant value of 1120 feet, representing the tailwater elevation with an allowance for hydraulic losses. Columns 9 and 10 are respectively the capacity and discharge of one unit operating with the head given in Column 8. The product of the capacity (Column 9) and 240 (the number of hours in a ten-day period) is the energy generated by one unit during a ten-day period, assuming no lack of outflows, and it is shown in Column 11. Columns 12 and 13 give the capacity and discharge corresponding to twelve units and they are calculated by multiplying the figures in Columns 9 and 10 by twelve. The ratio between the amount of water available for discharge (outflow, Column 5) and the maximum amount of water which could be discharged by twelve turbines (Column 13) is given in Column 15 as o.f. (operation factor). The energy generated by twelve units, which is the product of the energy output of one unit (Column 11), twelve and the operation factor (Column 15), is shown in Column 14.

The consultants studied a number of alternative operations of the Tarbela Reservoir -- drawdown levels of 1300 feet, 1332 feet and 1350 feet and a variety of different release patterns. Table 11 shows two out of the several release patterns studied -- the one adopted by the power consultant as the basis for most of his planning and the one finally recommended by the irrigation consultant. The 'final' release pattern was chosen with a view to both irrigation and power considerations.

Table 11

Tarbela Release Patterns

Expressed as Percentage of Usable Storage
(Positive Figures Show Releases -- Negative Figures Show Storage)

	Stone & Webster	IACA Final
October	1	0
November	8	8
December	10	11
January	14	21
February	21	26
March	20	19
April	18	10
May	8	5
June	-45	-45
July	-55	-55
August	0	0
September	0	0

The Bank Group also considered a number of alternative operations of the Tarbela Reservoir. The chief ones are presented in the following Table 12.

Table 12

Tarbela Reservoir -- Alternative Operations
(Bank Group Manual Simulation)

Release Pattern	Final	Final	Final
Maximum Reservoir Level (feet)	1550	1550	1550
Minimum Reservoir Level (feet)	1300	1332	1396
Initial Live Storage (MAF)	9.30	8.60	6.80
Firm Capacity (critical & mean-year) (mw)	456 (June 1)	732 (June 1)	1296 (June 1)
Annual Energy Generation (million kwh)	12,685	13,154	13,370
Number of Units in Operation	12	12	12

All of these studies were carried out on the basis of the final compromise release pattern.

Comparison between the figures on energy output and capabilities which come out of the Bank Group's manual simulation of Tarbela Reservoir operation and the consultants' computer simulation shows that the two procedures lead to very similar results. The only major variation occurs at the highest reservoir levels where the turbine characteristics used for the manual simulation show a larger output than those apparently used in the computer studies (about 8 mw per unit or 4 percent). Below maximum reservoir elevation the capability figures resulting from the two approaches are virtually identical. The energy figures which come out of the manual simulation are generally slightly, but hardly significantly, above those derived from the computer simulation for a number of reasons -- the higher capabilities in the manual simulation at full reservoir levels, slight differences in release pattern, and lack of allowance in the manual simulation for turbine losses and for siltation of the reservoir.

Study of the alternatives prepared by the Bank Group and by the consultants shows that raising the Tarbela drawdown level from 1300 feet to 1332 feet, 1350 feet and 1396 feet increases the firm capacity of twelve units (at the beginning of June) from 456 mw to 732 mw, 896 mw and 1296 mw, or an average of about 9 mw increase in output for each foot of increase in the minimum reservoir level. The initial live storage, on the other hand, with these changes in minimum reservoir level, is reduced from 9.3 MAF to about 6.8 MAF, or at an average rate of about 0.022 to 0.028 MAF per foot of change in the minimum reservoir level. The change in total annual energy production (under mean-year conditions) resulting from a change in the minimum reservoir level is very small, as indicated by Table 12.

Table 13 presents the data which were derived from the manual simulation of reservoir operation for the first two cases listed in Table 12 -- drawdown levels of 1300 feet and 1332 feet -- and which were used in the power system simulation studies for purposes of the system dispatch. 1/

Table 13

Tarbela -- Data Used in Power System Simulation Studies
(FSL. 1550', Mean Year, 12 Units)

	Drawdown Level 1300'		Drawdown Level 1332'	
	Capability (mw)	Energy (mln. kwh)	Capability (mw)	Energy (mln. kwh)
Jan.	2208	1027	2220	964
Feb.	1660	994	1764	977
Mar.	1124	737	1296	746
Apr.	752	531	972	621
May	520	372	786	570
June	1342	972	1704	1224
July	2340	1685	2520	1818
Aug.	2520	1815	2520	1818
Sept.	2520	1815	2520	1818
Oct.	2520	1008	2520	1012
Nov.	2520	834	2520	814
Dec.	2450	795	2460	772
		12,585		13,154
Minimum Capability:	456 mw (June 1)		732 mw (June 1)	
Total Energy:	12,585 mln. kwh.		13,154 mln. kwh.	

1/ It will be noted that the energy figures diverge slightly from those given in Table 10; again the reason is that the two analyses were based on slightly different assumptions regarding the distribution of mean-year flows among ten-day periods.

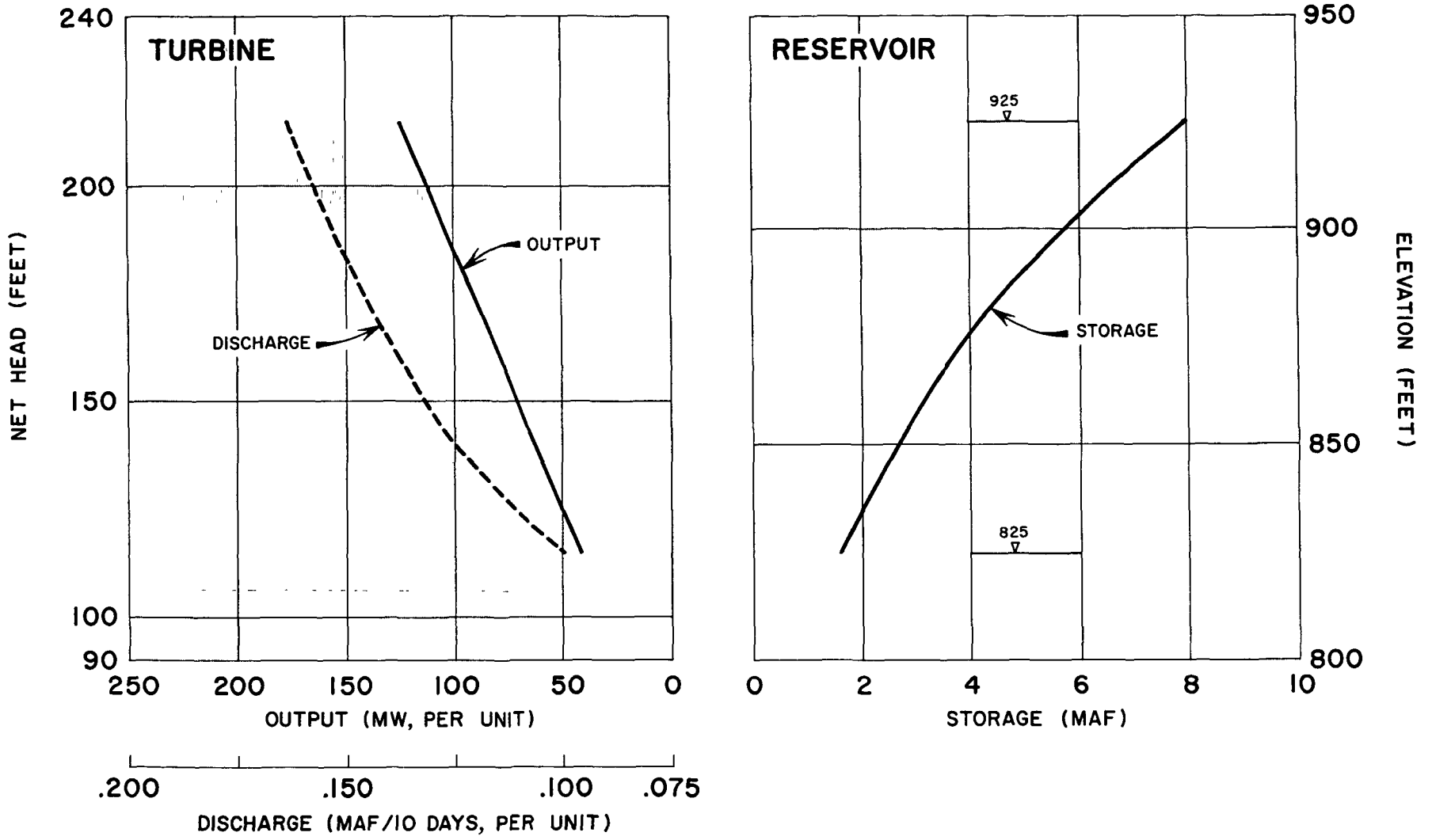
Kalabagh

The Bank Group made some studies of Kalabagh Dam and Reservoir. One such study concerned the power potential of the Kalabagh Project if it is constructed as a sequel to Tarbela, as recommended by the dam sites consultant. Flows at Kalabagh were assumed to be equal to Indus flows measured at Attock. The monthly figures for the mean year were divided by three in order to obtain average flows for ten-day periods. The storage elevation relationship at Kalabagh is given in the report of the dam sites consultant and reproduced in Figure 5. The dam sites consultant also indicated the maximum output of each turbine to be 125 mw at elevation 925 feet (net head 215 feet) and the minimum output 41 mw at elevation 825 feet (net head 115 feet). A straight line relationship was then assumed between these two extreme points, as shown in Figure No. 4. The net head is derived by subtracting a constant figure of 710 feet from the elevation. The approximation thus obtained is within the margin of error of the calculations. No other turbine characteristic being available, use was made of a "rule of thumb" in order to calculate the discharge through the turbines: it was assumed that 14 cubic feet per second with a 1-foot net head produce one kw of power. This coefficient corresponds to an overall electromechanical efficiency of about 84 percent. The hydraulic losses are allowed for by the use of net-head figures.

It was assumed that Kalabagh would be emptied each year according to the same release pattern as Tarbela -- i.e. the IACA 'final' release pattern given in Table 11 above. However, it would start to fill only after the completion of filling at Tarbela. It is estimated that flows would be sufficient to fill the reservoir (live storage of 6.4 MAF between minimum elevation of 825 feet and maximum elevation of 925 feet) completely in August and at the same time maintain a continuous release of 104,000 cfs throughout the month to meet downstream irrigation requirements.

Table 14 gives the estimated capacity available and energy produced at Kalabagh under these assumptions, with nine units and drawdown level of 825 feet.

KALABAGH RESERVOIR AND TURBINE CHARACTERISTICS



IBRD-3438

VOLUME IV
ANNEX 6-APPENDIX 1
FIGURE 4

Table 14

Kalabagh Reservoir Operation -- 9 Units
Capacity (mw) and Energy (million kwh)

Date	Capacity	Energy	Date	Capacity	Energy	Date	Capacity	Energy
Oct. 1	1125	222	Feb. 1	909	203	June 1	369	88
Oct. 11	1125	222	Feb. 11	846	188	June 11	369	88
Oct. 21	1125	221	Feb. 21	783	173	June 21	369	88
Nov. 1	1125	195	Mar. 1	720	155	July 1	369	88
Nov. 11	1107	191	Mar. 11	648	142	July 11	369	88
Nov. 21	1089	190	Mar. 21	594	125	July 21	369	88
Dec. 1	1080	194	Apr. 1	522	119	Aug. 1	369	192
Dec. 11	1062	194	Apr. 11	495	110	Aug. 11	801	270
Dec. 21	1044	191	Apr. 21	459	101	Aug. 21	1125	270
Jan. 1	1017	236	May 1	423	99	Sept. 1	1125	270
Jan. 11	981	227	May 11	414	93	Sept. 11	1125	270
Jan. 21	945	218	May 21	387	88	Sept. 21	1125	270
						TOTAL:		6,167

Warsak and Small Hydels

Table 15 gives the data regarding monthly capabilities and monthly energy output for Warsak and the eight existing small hydels as assumed for the purposes of the power system simulation model. Data on the small hydels was taken from the Stone & Webster final report -- A Program for the Development of Power in West Pakistan (May 1966), Volume II. Data on the existing Warsak units and on the potential addition to power generation obtainable by installing units 5 and 6 was taken from the WAPDA Grid System Power Data Reference Book (May 1964) compiled by Harza and WAPDA.

Table 15

Warsak and Small Hydels: Monthly Pattern of Capabilities and Energy Output

	Eight Small Hydels		WARSAK Units 1-4		WARSAK Units 1-6 w/o rereg'n.		WARSAK Units 1-6 with rereg'n.	
	mw	mln. kwh.	mw	mln. kwh.	mw	mln. kwh.	mw	mln. kwh.
Jan.	55	40	100	46	100	46	180	46
Feb.	55	40	100	40	100	40	180	40
Mar.	75	54	100	67	100	67	180	67
Apr.	85	54	160	115	240	159	240	159
May	85	56	160	119	240	178	240	178
June	85	62	160	115	240	173	240	173
July	85	62	160	119	240	178	240	178
Aug.	85	62	160	119	240	178	240	178
Sept.	85	62	160	115	240	140	240	140
Oct.	65	48	100	70	100	70	180	70
Nov.	55	40	100	51	100	51	180	51
Dec.	55	40	100	48	100	48	180	48

Kunhar

Table 16 gives the data regarding monthly capabilities and monthly energy output for Kunhar as assumed for the purposes of the system dispatch in the power system simulation model. These figures

are taken from the Stone & Webster report, Draft Report on Water and Power Resources of West Pakistan, Stage II -- Electric Power -- 1964 Tarbela Study (December 1964).

Table 16

Kunhar: Monthly Pattern of Capabilities and Energy Output (Cumulative)

Units Added	Paras 1 and 2		Paras 3		Paras 4		Suki Kinyari 1, 2 and 3	
	mw	mln kwh	mw	mln kwh	mw	mln kwh	mw	mln kwh
Jan.	230	82	345	192	459	192	567	233
Feb.	224	67	336	177	448	177	549	215
Mar.	216	97	324	202	432	202	524	239
Apr.	209	119	313	180	418	180	503	215
May	203	151	304	182	406	182	491	214
June	226	163	339	176	452	176	573	214
July	234	174	351	242	468	242	594	286
Aug.	234	174	351	262	468	348	594	394
Sept.	234	168	351	230	468	230	594	276
Oct.	234	110	351	162	468	162	594	202
Nov.	234	75	351	156	468	156	591	196
Dec.	234	76	351	177	468	177	586	220

Paras and Suki Kinyari are the names of the two power plants which constitute the Kunhar project. The first stage of the project, as envisaged by Chas. T. Main, would involve construction of the Suki-Kinyari Reservoir on the Kunhar River and a tunnel to take water from the reservoir to Paras, where steel penstocks would deliver the water to four generating units. The second stage of the project would involve construction of a second small reservoir on the Kunhar at Naran, upstream of Suki Kinyari, and of a power plant with three units at the head of the Suki Kinyari Reservoir; water would be delivered to penstocks at Suki Kinyari by the Naran-Suki Kinyari power tunnel.

APPENDIX II

HYDROELECTRIC PLANT COST DATA

Table 1

The Capital Costs of Firm Hydro Capacity (Including Transmission from Plant to Northern Grid)
(US Dollars per kw)

	Firm Capacity (mw)	Economic Costs: Foreign Exchange	Economic Costs: Domestic	Economic Costs: Total	Foreign Exchange as Percent of Total
Mangla 1040'					
Unit 4	45	111	27	138	80.4
Units 5 & 6	90	145	53	198	73.2
Units 7 & 8	90	155	44	199	77.8
Mangla 1075'					
Unit 4	63	79	19	98	80.6
Units 5 & 6	126	103	38	141	73.0
Units 7 & 8	126	110	32	142	77.4
Tarbela 1300'					
Units 1 & 2	108	387	176	563	68.7
Units 3 & 4	108	96	23	119	80.6
Units 5 & 6	108	398	180	578	68.8
Units 7 & 8	108	96	23	119	80.6
Units 9 & 10	108	398	180	578	68.7
Units 11 & 12	108	96	23	119	80.6
Tarbela 1332'					
Units 1 & 2	146	286	130	416	68.7
Units 3 & 4	146	71	17	88	80.6
Units 5 & 6	146	295	132	427	69.0
Units 7 & 8	146	71	17	88	80.6
Units 9 & 10	146	295	132	427	69.0
Units 11 & 12	146	71	17	88	80.6
Warsak Units 5 & 6					
With reregulation	140 (March)	92	38	130	70.7
With reregulation	80 (May)	151	67	228	70.6
Without reregulation	80 (May)	68	35	103	66.0
Kunhar (Paras units 1-4 and Suki Kinari units 1-3)					
Capability	524(March)	244	144	388	62.8
Capability	491(May)	260	154	414	

Note: Firm Capacity is taken as capacity in the ten-day period which is expected to be most critical: i.e. last ten days of March when Mangla is on line, changing after the first 2-6 units are installed at Tarbela to the first 10 days of May. Tarbela firm capacities are therefore given above as of the first ten days of May, while Mangla firm capacities are given as of the last ten days of March. The firm capacity of Warsak Units 5 and 6 can only be considered within the general framework set by the dominant weight of Mangla and Tarbela. Before Tarbela, i.e. when the critical period is the last 10 days of March, Warsak Units 5 and 6 with reregulation would have effectively a firm capacity of 140 mw and without reregulation a firm capacity of zero. After Tarbela, i.e. when the critical period is the first ten days of May, Warsak Units 5 and 6 would have a firm capacity of 80 whether or not the reregulating works were installed downstream.

ANNEX 6
Appendix II

Table 2

Tarbela: Costs as Used in Power Simulation Program
(Million US Dollars)

Domestic/Foreign	Domestic									Foreign									Total Foreign Domestic
Year	-6	-5	-4	-3	-2	-1	0	1	Total	-6	-5	-4	-3	-2	-1	0	1	Total	
Units 1 & 2																			
Power Unit 1	0.2	4.0	2.5	3.2	2.0	1.0			12.9	0.5	9.1	5.7	7.2	4.6	2.3			29.4	42.3
Power Unit 2				0.3	0.3	0.2	0.1		0.9				1.0	1.3	0.8	0.4		3.5	4.4
Transmission s/c 380					0.9	2.4	0.9		4.2					1.2	2.9	1.2		5.3	9.5
Line Terminals						0.2			0.2						0.8			0.8	1.0
Step-up Transformers						0.4			0.4						1.4			1.4	1.8
Step-down Transformers						0.4			0.4						1.4			1.4	1.8
TOTAL	0.2	4.0	2.5	3.5	3.2	4.6	1.0		19.0	0.5	9.1	5.7	8.2	7.1	9.6	1.6		41.8	60.8
Units 3 & 4																			
Power Units			0.5	0.6	0.4	0.2			1.7			2.0	2.5	1.7	0.8			7.0	8.7
Step-up Transformers					0.4				0.4					1.7				1.7	2.1
Step-down Transformers					0.4				0.4					1.7				1.7	2.1
TOTAL			0.5	0.6	1.2	0.2			2.5			2.0	2.5	5.1	0.8			10.4	12.9
Units 5 & 6																			
Power Units			4.0	5.0	3.3	1.7			14.0			9.4	11.8	7.8	3.9			32.9	46.9
Transmission s/c 380					0.9	2.4	0.9		4.2					1.2	2.9	1.2		5.3	9.5
Line Terminals						0.2			0.2						0.8			0.8	1.0
Step-up Transformers						0.5			0.5						2.0			2.0	2.5
Step-down Transformers						0.5			0.5						2.0			2.0	2.5
TOTAL			4.0	5.0	4.2	5.3	0.9		19.4			9.4	11.8	9.0	11.6	1.2		43.0	62.4

Tarbela 7 & 8 have same total costs as 3 & 4
Tarbela 11 & 12 have same total costs as 3 & 4
Tarbela 9 & 10 have same total costs as 5 & 6

Source: Stone & Webster, "A Program for the Development of Power in West Pakistan, Volume II (Annexes)", May 1966, and Power Consultant's working papers.

Note: Year 0 is year when the capability of the units comes on line.

Table 3

Mangla: Costs as Used in Power Simulation Program
(Million US Dollars)

Domestic/Foreign	Domestic							Foreign							Total Foreign & Domestic
Year	-4	-3	-2	-1	0	1	Total	-4	-3	-2	-1	0	1	Total	
Unit 4															
Power Unit		0.2	0.2	0.3	0.3		1.0		0.9	1.2	1.6	0.7		4.4	5.4
Step-up transformer				0.2			0.2				0.6			0.6	0.8
TOTAL		0.2	0.2	0.5	0.3		1.2		0.9	1.2	2.2	0.7		5.0	6.2
Units 5 & 6															
Power Units		0.2	0.2	0.5	0.7		1.6		1.2	1.2	3.0	1.3		6.7	8.3
Transmission -															
Mangla-Midway				1.3	0.5		1.8				1.6	0.5		2.1	3.9
Midway-Lyallpur				0.4	0.1		0.5				0.6	0.3		0.9	1.4
Line Terminals				0.2		0.1	0.3				0.7		0.2	0.9	1.2
Step-up transformers				0.3			0.3				1.2			1.2	1.5
Step-down transformers				0.3			0.3				1.2			1.2	1.5
TOTAL		0.2	0.2	3.0	1.3	0.1	4.8		1.2	1.2	8.3	2.1	0.2	13.0	17.8
Units 7 & 8															
Power Units		0.7	0.9	0.6	0.3		2.5		2.9	3.6	2.4	1.2		10.1	12.6
Transmission -															
Mangla-Midway				0.6	0.2		0.8				0.7	0.2		0.9	1.7
Line terminals				0.1			0.1				0.5			0.5	0.6
Step-up transformers				0.3			0.3				1.2			1.2	1.5
Step-down transformers				0.3			0.3				1.2			1.2	1.5
TOTAL		0.7	0.9	1.9	0.5		4.0		2.9	3.6	6.0	1.4		13.9	17.9

Source: Stone & Webster, "A Program for the Development of Power in West Pakistan, Volume II (annexes)" May 1966, and power consultant's working papers.

Note: Year 0 is year when the capability of the units comes on line.

Table 4

Warsak Units 5 & 6: Costs as Used in Power Simulation Program
(millions US dollars)

Year	-3	-2	-1	0	Total
Without Reregulation					
Foreign	0.9	1.1	2.2	1.2	5.4
Domestic	0.5	0.6	1.1	0.6	2.8
Total	1.4	1.7	3.3	1.8	8.2
Reregulating Facilities					
Foreign	1.8	2.0	2.2	1.5	7.5
Domestic	0.6	0.7	0.7	0.5	2.5
Total	2.4	2.7	2.9	2.0	10.0
Total with Reregulation					
Foreign	2.7	3.1	4.4	2.7	12.9
Domestic	1.1	1.3	1.8	1.1	5.3
Total	3.8	4.4	6.2	3.8	18.2

Source: WAPDA, November 1966

Table 5

Kunhar: Costs as Used in Power Simulation Program and Timing of the Completion of Units
(Million US Dollars)

Year	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	Total
Foreign											
Dams & power units	3.2	14.8	17.5	23.6	13.0	17.6	12.7	6.7	2.8		111.9
220 kv transmission, Kunhar-Lyallpur				1.0	4.0	2.0	2.0	5.0	2.0		16.0
Subtotal, Foreign	3.2	14.8	17.5	24.6	17.0	19.6	14.7	11.7	4.8		127.9
Domestic											
Dams & power units	1.5	10.5	13.1	14.9	10.0	7.8	5.5	2.4	0.8		66.5
220 kv transmission, Kunhar-Lyallpur				1.0	2.0	1.0	1.0	3.0	1.0		9.0
Subtotal, Domestic	1.5	10.5	13.1	15.9	12.0	8.8	6.5	5.4	1.8		75.5
GRAND TOTAL	4.7	25.3	30.6	40.5	29.0	28.4	21.2	17.1	6.6		203.4

Availability of Units (mw rating)

Kunhar 1: Paras units 1 & 2						220				
Kunhar 2: Paras unit 3								110		
Kunhar 3: Paras unit 4									110	
Kunhar 4: Suki Kinyari units 1, 2 & 3										120

Source: Stone & Webster, "Draft Report on Water and Power Resources of West Pakistan Stage II - Electric Power 1964 Tarbela Study Volume 1" (December 1964) Exhibit V-9 and subsequent discussion with power consultant. The cost estimates given in this Stone & Webster report were based on those given in Charles T. Main's supplemental report on the Kunhar River Project without allowance for increases in prices in the interim. They are therefore likely to be on the low side in comparison with the cost estimates used elsewhere in these studies, which are supposed to be in 1965 prices. The allowance for two double-circuit 220 kv lines from Kunhar to Lyallpur which was added for the case of Kunhar without Tarbela might be excessive for the case of Kunhar after Tarbela if Kunhar can be linked with the 380 kv transmission system then existing. However, it is in fact more likely that further investigation would reveal the Kunhar Project to be more expensive in terms of 1965 prices rather than less expensive.

Table 6

Operation and Maintenance Costs of Hydro Plants as used in Computer Studies

	Million $ per annum
Warsak	0.3
Mangla	
Units 1 & 2	0.3
3 & 4	0.15
5 & 6	0.13
7 & 8	0.12
Total	0.7
Tarbela	
Units 1 & 2	0.3
3 & 4	0.13
5 & 6	0.15
7 & 8	0.10
9 & 10	0.15
11 & 12	0.10
Total	0.9
Kunhar	
Paras 1 & 2	0.3
Paras 3 & 4	0.1
Suki-Kinyari 1 - 3	0.2
Total	0.6

An allowance of 1 percent of construction costs of transmission lines linking Tarbela, Mangla and Kunhar to the Northern Grid was added, as appropriate, to the figures cited above to cover O & M costs on these transmission lines.

ANNEX 7

THE POWER ASPECTS OF THE TARBELA PROJECT

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Table of Contents

THE POWER ASPECTS OF THE TARBELA PROJECT

The Tarbela Project, as now planned, will be the largest water storage and hydroelectric project in Pakistan; in fact, it will probably also be the largest single contract ever to have been let in the world. As discussed in Volume III, Tarbela Dam site was selected by WAPDA in 1961 as a result of detailed studies of three potential sites in a 15-mile stretch of the Indus River that began in 1954. Tippetts-Abbett-McCarthy-Stratton International Corporation (TAMS) of New York City, consulting engineers to WAPDA, are now completing the final designs and contract documents for the project. The project, as now envisaged, comprises essentially a major earth and rockfill dam rising 485 feet above riverbed level with a crest length of about 9,000 feet and an impervious blanket extending some 5,000 feet upstream, two auxiliary embankment dams, two chute spillways, and four outlet tunnels each of 45 feet maximum diameter.

The powerhouse would be located on the right bank of the river at the foot of the dam. The substructure is designed to be constructed in stages of four generating units each and each group of four units will be served by one penstock tunnel. It has recently been decided to build the powerhouse initially for four or eight generating units. On present designs the third tunnel will be adaptable for power use when required. The fourth tunnel is being designed strictly for irrigation, but it would be possible to make it adaptable for power purposes as well, thus enabling an additional four units to be installed, making 16 units in all. Each unit, rated at 175 mw, would have a capability range of 183 mw, or 210 mw with 15 percent overload, under full head and low tailwater conditions to about 40 mw at the 1300 foot drawdown level.

High Seasonal Fluctuation in Power Availability

It was pointed out in Annex 6 that the extreme seasonal fluctuations in flows on the Indus and the variation in storage releases required for irrigation purposes in the different months of the year provide a poor seasonal distribution of water for power production. The range of variation in the capability of the units at Tarbela is indicated in the following table.

Table 1(a)

Tarbela - Gross Capacity of 1 Unit in Different Months

	Drawdown Level 1332'		Drawdown Level 1300'	
	mw	mln kwh	mw	mln kwh
Minimum				
May 11-21	69	50	50	37
May 21-31	64	47	42	31
June 1-10	61	45	38	28
Maximum				
August	210	153	210	153
September	210	153	210	153

The exact significance of these minimum capabilities will depend on the monthly pattern of peak loads and the seasonal variation in the capability of other hydro units on the system at the same time. It will be seen below that, even though Tarbela will reach minimum capability in early June, the critical period on the system as a whole is likely to be in May when Tarbela is fully developed because Mangla, having begun to fill earlier, will be well above minimum capability by the beginning of June.

Units 13-16 at Tarbela

Though it would be possible to install 16 units at Tarbela as pointed out earlier, the analyses presented in this annex were conducted in terms of a maximum of 12 units. The main attraction of units 13-16 is that they would add capability, generally capable of producing base-load energy in the critical period of the year from the end of April to the beginning of June. Thus, depending on the minimum reservoir level maintained, they would add to system firm capability in the 1980's about 200 mw (in early May, with drawdown level of 1300 feet) or about 260 mw (in early May, with drawdown level of 1332 feet). With a minimum drawdown level of 1332 feet, they would add about 200 million kwh of energy during the critical May-June period under mean-year conditions. They would also add about another 1,800 million kwh to the output of the Tarbela power plant in June-September, but our studies suggest that the other hydro units envisaged (i.e. existing plants plus Mangla 1-8 and Tarbela 1-12) would already be producing more energy in most of these months than could be absorbed by the system until the late 1980's. However, it is also about that time -- the late 1980's -- that the release capacity of the tunnels as presently designed (i.e. three for power and one for irrigation) may, according to the irrigation consultant's projections of kharif irrigation requirements, become inadequate to permit required releases during the period when the reservoir is fully drawn down. Conversion of the fourth tunnel to power would cut the maximum outlet capability of one irrigation tunnel plus three power tunnels (including their bypass valves) from about 118,000 cfs to about 65,000 cfs at reservoir elevation 1332 feet. Irrigation requirements for releases in June have been projected at 156,000 cfs by 2000. Straight conversion of tunnel No.4 to power would thus be unacceptable from the irrigation point of view. Other solutions, such as addition of a fifth tunnel, would be extremely expensive. 1/ The power consultant, making allowance only for the lining of the downstream end of tunnel 4 and its adaptation for power use, estimated that units 13-16 would be about 40 percent more expensive than other Tarbela units. This would put them at about $350 per kw available at the time of system minimum capability. He pointed out that additional transmission would be required to carry the power generated in the flood season. Addition of these costs and of the costs of adjustment to meet irrigation requirements, even on the assumption that some relatively inexpensive solution to this problem might yet be found, would seem to make Tarbela units 13-16 unattractive compared with

1/ See Chas. T. Main, Program for Development of Surface Storage in the Indus Basin and Elsewhere within West Pakistan: Comprehensive Reports Volume II (August, 1966), pp. II-1-22 through II-1-27.

alternatives available to Pakistan for the period of 20 to 30 years with which we are here concerned. The situation could be very different 40 years after Tarbela is completed when the higher drawdown level will increase the minimum discharge through the power tunnels and additional storage will be available elsewhere to meet the main irrigation requirements.

Power Benefits of Tarbela

It was pointed out in Annex 6 that a dual approach was taken to the evaluation of Tarbela's power benefits. In both approaches, net benefits were identified as the difference between the cost of a power program including Tarbela and one excluding Tarbela. The first approach compared Tarbela with the cheapest alternative power program and showed the sensitivity of the benefits to different assumptions regarding the foreign exchange rate and fuel prices. The alternative power program for this purpose was built on the assumption that if Tarbela was not built by 1975/76 it would never be built. However, the capital cost savings obtainable from postponing such a major investment as the Tarbela Project by even a few years are considerable, and therefore a second analysis was undertaken comparing a program which included completion of the Tarbela Dam in 1975 with another program which included its completion in 1985. Since the first approach showed Tarbela to be an attractive project from the power point of view at any likely fuel price in West Pakistan, and the second analysis was concerned with its precise timing, all the calculations for the second approach were made in terms of the economic fuel prices shown in Figure 1 of Annex 5; for these fuel prices represent estimates of the scarcity value of thermal fuel in each year of the planning period.

Establishing the Cheapest Alternative to Tarbela

The first task was to establish the best alternative to Tarbela from the power point of view. In their 1964 report on the Tarbela Project, Stone & Webster had prepared an alternative program which included the Kunhar Project and extensive thermal development at Mari with a 380-kv transmission line linking Mari and the North. These alternative programs were designed to meet only the power requirements of the Northern Grid zone. However, the basic elements of this program were used to develop an alternative program to Tarbela for meeting the requirements of all the main load centers of West Pakistan.

The first alternative program prepared included a 380-kv interconnection between Mari and Karachi (thus enabling advantage to be taken of the gas reserves at Mari) and the Kunhar Project with its two stations in series and an ultimate installed capacity of 560 mw (see Volume III Annex 6 for details of this project). It was found that, except at rather high prices for thermal fuel, Kunhar was a relatively unattractive project. Therefore, two other programs were prepared, one including Kunhar commencing in 1981, and the other excluding Kunhar altogether. The last in effect constitutes a purely thermal alternative (except for the existing small hydels and Warsak, and the planned Mangla units 1-8 and Warsak units 5 and 6). Since it is now very doubtful whether there exists

at Mari such a large reserve of cheap gas as was believed to be the case two years ago, the 380-kv transmission line between Mari and Karachi was also eliminated from the program. Since most of this analysis was conducted in terms of uniform fuel prices, this also served to focus attention entirely on the effects of changes in assumptions regarding the availability and price of fuel.

The resultant development programs are outlined in detail in the following Table 1. On the right hand side are shown a single program for Mari and a single program for Karachi-Hyderabad. They were combined with each of the three different programs shown on the left for the Northern Grid: Program A including Kunhar coming in in 1974, Program B including Kunhar commencing 1981, and Program C being the so-called all-thermal program. These programs could undoubtedly be refined. The direction of refinement would often depend, however, on making a more precise initial assumption with regard to the price of thermal fuel. For instance, the Mangla units are probably scheduled earlier than would be sensible without interconnection unless the fuel price is assumed to be very high. Other refinements would be possible too -- adequate allowance is not always made for reserves and some of the units brought in are larger than would be appropriate for markets of the size that will be in existence if interconnection is not undertaken. For the purpose of a rough assessment of the power benefits from Tarbela at different fuel prices, however, the programs seem adequate.

Figure 1 compares the discounted present worth of the cost of these programs at different prices for natural gas. Virtually all the thermal generation in these programs is assumed to be gas-fired; the only significant exception to this is a small amount of nuclear capability included in the South in each of the programs for the early 1980's. Natural gas was also assumed, for these analyses, to have a uniform price throughout West Pakistan. Therefore, the figure gives a direct indication of the effect that different assumptions regarding fuel have on the relative attractiveness of various programs alternative to Tarbela.

Side Benefits to Kunhar

There are two side benefits which have to be taken into account in consideration of the Kunhar Project. In the first place, it would provide a small amount of live storage. The project, as designed by Chas. T. Main, would include live storage of about 0.128 MAF behind the Suki-Kinari Dam, which would be completed about 1973/74 in our early Kunhar program and about 0.250 MAF behind the Naran Dam which would be completed about 1975/76 under the same program. The linear programming analysis of agricultural development suggests that the present worth of the benefit of this storage capacity might be about $10 million. Apart from these irrigation benefits, regulation of the Kunhar River, a tributary of the Jhelum, could also increase the capability of the Mangla units in the critical period from March through May and increase the amount of energy which could be generated at Mangla in those months by storing kharif water and releasing it in the critical months. Insufficient information is available

TABLE 1

ALTERNATIVE PROGRAMS WITHOUT TARBELA

	North, Program A		North, Program B		North, Program C		North	Mari			Karachi-Hyderabad		
	System Additions	Capability (mw)	System Additions	Capability (mw)	System Additions	Capability (mw)	Peak Load(mw)	System Additions	Capability (mw)	Peak Load (mw)	System Additions	Capability (mw)	Peak Load(mw)
1966	Existing	467	Existing	467	Existing	467	513(Oct)	Existing	50	11(Oct)	Existing	280	194(Dec)
1967	Lyallpur S1(124) Mangla 1 & 2 (90)	457	Lyallpur S1(124) Mangla 1 & 2 (90)	457	Lyallpur S1(124) Mangla 1 & 2 (90)	457	513(Jan)		50	17(Oct)	Hyderabad S2(15) Kotri OFT (12)	307	225(Oct)
1968	Lahore GT2 (26) Lahore GT3 (26)	743	Lahore GT2 (26) Lahore GT3 (26)	743	Lahore GT2 (26) Lahore GT3 (26)	743	598(Mar)		50	22(Oct)	Kotri GT (40)	347	271(Oct)
1969	Mangla 3 (45)	788	Mangla 3 (45)	788	Mangla 3 (45)	788	690(Mar)		50	29(Oct)	Korangi 3 (125)	472	321(Oct)
1970	Mangla 4 (45) Mangla 5 & 6 (90)	923	Mangla 4 (45) Mangla 5 & 6 (90)	923	Mangla 4 (45) Mangla 5 & 6 (90)	923	813(Mar)	Mari 1(100)	150	45(Oct)	Hyderabad GT2(26)	498	382(Oct)
1971	Lyallpur P (100) Retire: LYA S (10) MONT S (5)	1008	Lyallpur P (100) Retire: LYA 5 (10) MONT S (5)	1008	Lyallpur P (100) Retire: LYA S(10) MONT S(5)	1008	909(Mar)		150	54(Oct)	Karachi N1 (25) Korangi 4 (125)	648	442(Oct)
1972	Mangla 7 & 8 (90)	1098	Mangla 7 & 8 (90)	1098	Mangla 7 & 8 (90)	1098	1004(Mar)		150	65(Oct)	Karachi N1 (100)	748	514(Oct)
1973	Lyallpur 1 (100)	1198	Lyallpur 1(100)	1198	Lyallpur 1 (100)	1198	1099(Mar)		150	76(Oct)	Retire: KAR A(15)	733	600(Oct)
1974	Kunhar 1 (216)	1404	Lyallpur 2(100)	1298	Lyallpur 2 (100)	1298	1196(Mar)		150	89(Oct)	Karachi 1 (100)	833	692(Oct)
1975	Warsak 5 & 6 (80)	1484	Lyallpur 5 (150)	1528	Lyallpur 5 (150)	1528	1306(Mar)		150	105(Oct)	Karachi 2 (150)	983	795(Oct)
1976	Kunhar 2 (108)	1592	Warsak 5 & 6 (80)	1528	Warsak 5 & 6 (80)	1528	1394(Mar)	Mari 1a (100)	250	115(Oct)		983	889(Oct)
1977	Kunhar 3 (108)	1700	Lyallpur 5a (150)	1678	Lyallpur 5a (150)	1678	1493(Mar)		250	126(Oct)	Korangi 5 (200)	1183	998(Oct)
1978	Kunhar 4 (92)	1792	Lyallpur 5b (150)	1828	Lyallpur 5b (150)	1828	1601(Mar)		250	137(Oct)		1183	1101(Oct)
1979	Lyallpur 5 (150)	1942	Lyallpur 5c (150)	1978	Lyallpur 5c (150)	1978	1708(Mar)		250	148(Oct)	Karachi 3 (250)	1433	1234(Oct)
1980		1942		1978		1978	1837(Mar)		250	162(Oct)	Korangi 7 (300)	1733	1370(Oct)
1981	Lyallpur 6 (200)	2142	Kunhar 1 (216)	2194	Lyallpur 6 (200)	2178	1959(Mar)		250	178(Oct)		1733	1499(Oct)
1982	Lyallpur 7 (200)	2342	Lyallpur 7 (200)	2394	Lyallpur 7 (200)	2378	2087(Mar)	Mari 1b (100)	350	193(Oct)	Korangi 7a (300)	2033	1642(Oct)
1983	Lyallpur N1 (300)	2642	Kunhar 2 (108)	2502	Lyallpur N1 (300)	2678	2225(Mar)		350	210(Oct)		2033	1776(Oct)
1984		2642	Kunhar 3 (108)	2610		2678	2356(Mar)		350	229(Oct)	Korangi N4 (400)	2433	1971(Aug)
1985	Lyallpur 2 (100)	2742	Kunhar 4 (92)	2702	Lyallpur 2a (100)	2778	2505(Mar)		350	250(Oct)		2433	2154(Aug)

to make a full analysis of the benefits attributable to Kunhar on this account, and the irrigation and power uses of the Kunhar storage could be incompatible depending on the timing of irrigation requirements. However, the added capability and energy generation at Mangla which would result from the construction of Kunhar have been estimated as follows:

Table 2

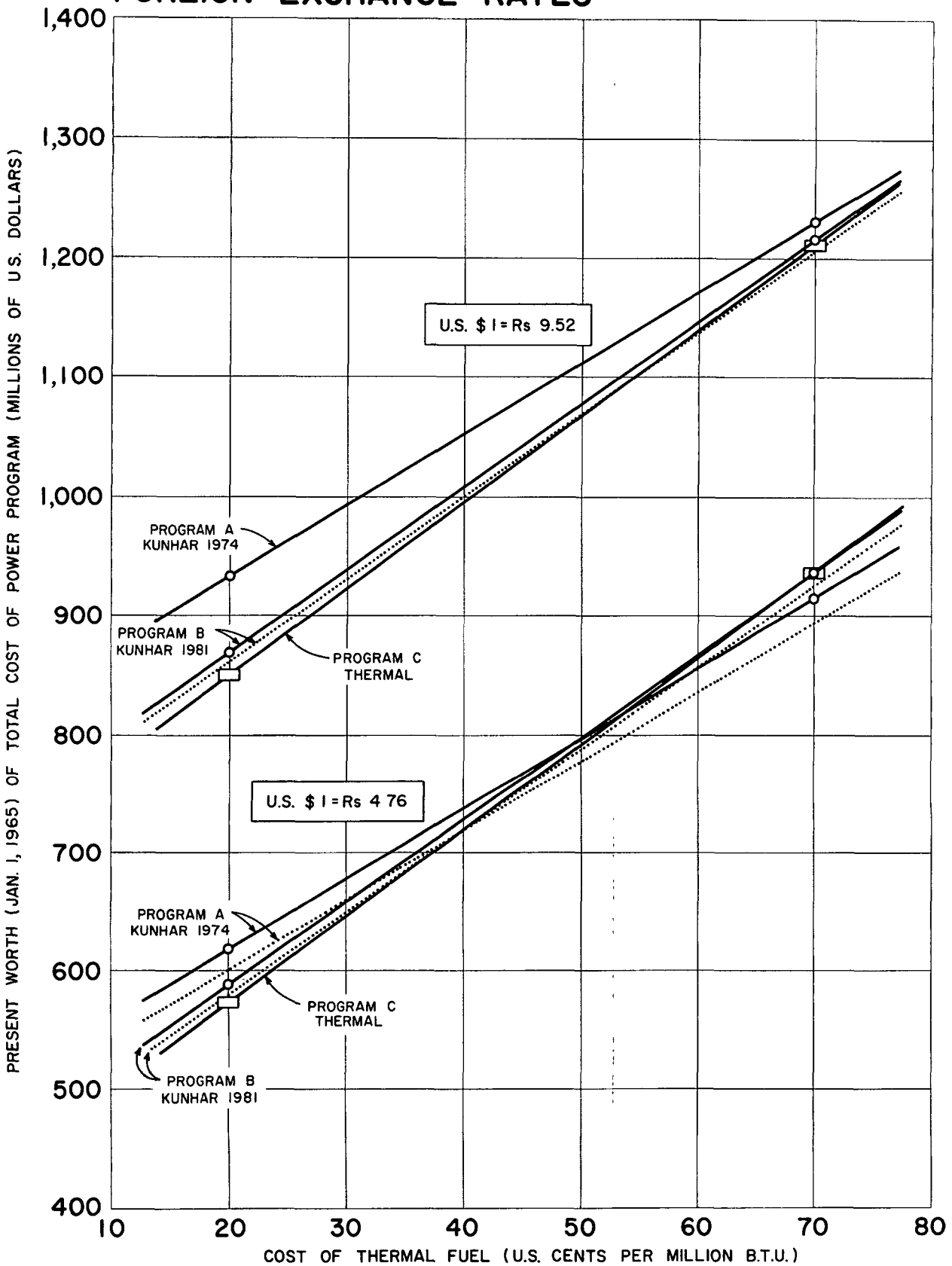
Effect of Kunhar on Power Output from Mangla a/
(Mangla 8 Units - Drawdown Level 1040')

	Critical Year Capability (mw)		Mean-Year Energy (mln kwh)	
	Without Kunhar	With Kunhar	Without Kunhar	With Kunhar
January	546	546	338	348
February	688	728	405	419
March	520	592	387	440
April	384	488	276	351
May	520	584	386	434
June	768	752	551	540
July	928	888	690	660

a/ These figures taken from the Stone & Webster "Draft Report on Water and Power Resources of West Pakistan - 1964 Tarbela Study" (December, 1964) are not directly comparable with other figures used in this annex. Months not mentioned in the table are not affected by the installation of the Kunhar dams.

These figures show that the important effects of Kunhar on Mangla are an increase of the capability in the critical month of March by about 70 mw and an increase in the amount of energy available in months when it could normally be used (i.e. excluding July) of nearly 200 million kwh. These are rough order-of-magnitude estimates but they serve for the present purpose. They imply that early construction of Kunhar could reduce the investment needed in new thermal capacity in 1978 by about 75 mw and increase the amount of useful hydro energy available after that date by about 200 million kwh a year. These savings have a present worth of about $6 million, if the fuel savings are valued at the low (20 cents) price for fuel and about $11 million if the fuel savings are valued at the high (70 cents) price for fuel. If Kunhar were to be postponed to 1981, as in Program B, then the irrigation benefits and power savings would have a combined present-worth value of about $8 million at the lower fuel price and $10 million at the higher fuel price. The results of these calculations are also indicated in Figure 1, by the dotted lines beneath the continuous lines which represent the direct costs of the various programs on the power side.

COMPARISON OF ALTERNATIVES TO TARBELA AT DIFFERENT FUEL PRICES AND DIFFERENT FOREIGN EXCHANGE RATES



(R)IBRD-3309

Appraisal of Kunhar as Alternative

The evidence presented in Figure 1 suggests that Kunhar is not a very attractive project, and that only by the addition of the side benefits which might accrue from its effect on irrigation supplies and on the capability at Mangla does it become marginally interesting. Even with foreign exchange valued at the current official rate, programs which include Kunhar are less attractive than the 'all-thermal' alternative at any fuel price below about 40 cents per million Btu. Without taking account of these special benefits of Kunhar the breakeven point arrives only at a fuel price of over 50 cents per million Btu. At the higher foreign exchange rate the programs including Kunhar are considerably less attractive; the program with Kunhar in 1974 is not at all competitive and that with Kunhar in 1981 breaks even with the 'all-thermal' alternative only at a fuel price of over 50 cents per million Btu.

There is another factor which raises doubts about Kunhar. The cost estimates for the project, except for the special addition made here to cover transmission, are all based on 1960 U.S. and Pakistani prices. Other prices used in this report are as of mid-1965. The magnitude of the adjustment that would be necessary to bring the Kunhar costs up-to-date is uncertain but this does suggest that the breakeven points between Kunhar and a purely thermal alternative given here are minima; Kunhar may well be attractive only if fuel prices are substantially higher.

The figures as they stand, however, would suggest that Kunhar is preferable to a thermal program only if foreign exchange is valued at the current rate. WAPDA now pays a price of somewhat below 50 cents per million Btu for the bulk of its thermal fuel, so that the 40 cents breakeven point for the Kunhar programs would imply that Kunhar is a sound project. When foreign exchange is valued at a rate closer to its true scarcity value the breakeven point between the two programs exceeds this fuel price. The result is confirmed by the figures in Table 3. The figures in this table represent the discounted present worth of the costs of three programs similar to those discussed above in every way, except that they each include development of about 1,000 mw at Mari/Sui and construction of a 380-kv transmission system between Mari and Karachi. The fuel requirements of these programs have been priced at the rate currently paid -- i.e. about 50 cents per million Btu for WAPDA-North, 44 cents for WAPDA-Sind and 36 cents for KESC -- together with an arbitrarily selected 'financial' price of 14 cents per million Btu at Mari/Sui. This table shows how the 'all-thermal' program is the worst when foreign exchange is valued at the current rate and the best when foreign exchange is valued at its scarcity price.

Table 3

Present Worth Costs of Alternative Programs
Excluding Tarbela with Fuel Valued at Current Prices to Utilities
(Million $)

	Foreign Exchange Rate	
	Current ($1 = PRs 4.76)	Shadow ($1 = PRs 9.52)
Program A (Kunhar 1974) a/	687	1,007
Program B (Kunhar 1981) a/	695	987
Program C (All-thermal)	697	984

a/ Total cost figures presented here net of present-worth value of special side benefits of Kunhar discussed above.

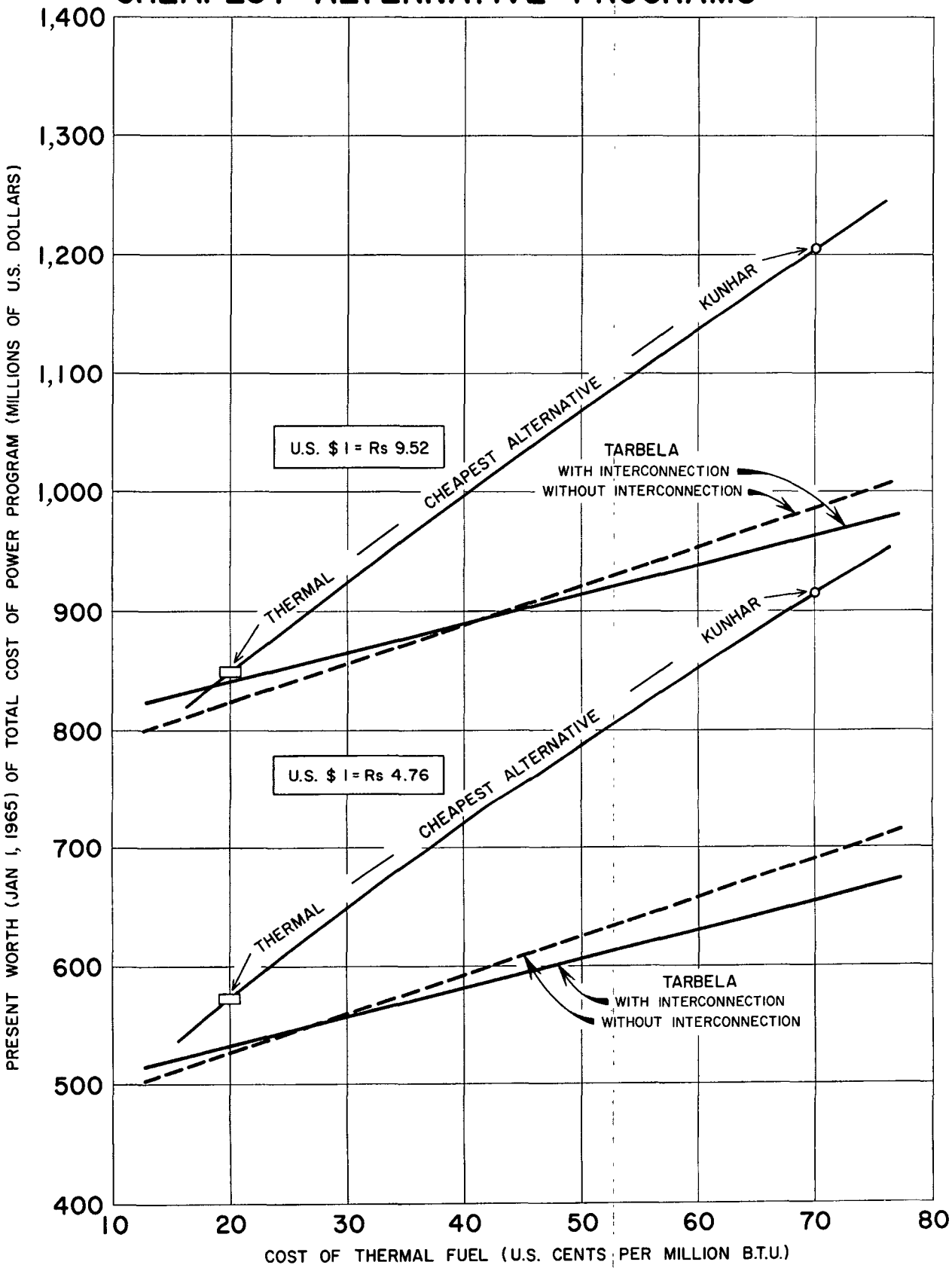
Programs Including Tarbela

Despite the uncertainty of the special side benefits which may accrue from construction of Kunhar, they were taken into account in the choice of programs constituting the cheapest alternative to Tarbela under various economic conditions. This helps to ensure that any error is in the direction of underestimating the power benefits of Tarbela rather than exaggerating them. These cheapest alternative power programs are compared in Figure 2 with two programs which include Tarbela in 1975. The two programs including Tarbela are outlined in Tables 4 and 5. The first (Table 4) omits interconnection and therefore phases the introduction of hydro units at Tarbela in accordance with the capacity of the Northern Grid to absorb additional hydro energy. The second program (Table 5) includes interconnection and brings in the Tarbela units more rapidly. Figure 2 compares the costs of these three programs at different shadow prices for fuel and for foreign exchange (i.e. excluding the cost of the Tarbela dams). As in the comparisons shown in Figure 1 thermal fuel is here assumed to have a single price wherever it may be used in the Province.

Programs Including Tarbela vs Cheapest Alternatives

It is clear from Figure 2 that power programs which include Tarbela are substantially cheaper than the cheapest alternative, in terms of discounted present worth, at all fuel prices above 20 cents per million Btu. Even at 20 cents per million Btu, fuel savings involved in a with-Tarbela program are about $40 million when foreign exchange is valued at the current rate, but they are almost insignificant when foreign exchange is valued at the higher rate used here. The costs of the programs cited here do not include the costs of gas transmission lines so that it is hard to apply here directly the estimates of the scarcity value of thermal fuel developed in Annex 5. Nevertheless, those estimates suggested that a reasonable middle range for comparing programs with and without the Tarbela contribution to overall energy supply might be at least 40-50 cents per million Btu. If the costs of

COMPARISON OF TARBELA WITH OR WITHOUT SYSTEMWIDE INTERCONNECTION WITH CHEAPEST ALTERNATIVE PROGRAMS



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the programs discussed here were revalued in terms of the fuel prices calculated in Annex 5 and the costs of needed gas pipelines were added in, the estimate of savings obtainable on the power side from a with-Tarbela program would probably appear greater because of the very high shadow fuel prices which seemed to be appropriate for the later years -- which is the bulk of the period when Tarbela would be providing power to West Pakistan. At a price of 45 cents per million Btu for thermal fuel the saving of a with-Tarbela program over the cheapest alternative is about $180 million at the current foreign exchange rate and $160 million at double the current rate.

Figures were cited above for the costs of without-Tarbela programs when fuel was valued at current financial prices. These programs included about 1,000 mw at Mari/Sui and so they are directly comparable with the with-interconnection Tarbela program here.

Table 6

Present-Worth Costs of Program With Tarbela and the Cheapest Alternative Without Tarbela with Fuel Valued at Current Prices to Utilities

(Million $)

	Foreign Exchange Rate	
	Current ($1 = PRs 4.76)	Shadow ($1 = PRs 9.52)
Cheapest Alternative	687	984
Program including Tarbela	569	877
Saving due to Tarbela	118	107

The figures given in this table may be taken as reasonable estimates of the benefits of Tarbela when calculations are made in terms of financial prices. As pointed out, both programs included extensive use of gas at Mari/Sui -- which has been valued in both sets of calculations at financial prices of 14 cents per million Btu. Annex 5 suggests that this price is low as a long-term average, as compared to the real economic value of West Pakistan's gas resources, although it is about the price at which Sui gas is purchased, after purification, by the pipeline companies.

The Power Benefits of Tarbela and Shadow Prices

This discussion suggests that valuation of the costs and benefits of Tarbela in terms of current prices tends to lead to underestimation. In one sense it exaggerates them: Tarbela looks slightly less attractive when foreign exchange is valued at its scarcity price than when it is valued at the current official price. This is in line with what might be expected: all foreseeable power generation and transmission programs make intensive use of capital equipment purchased with foreign exchange, but programs including Tarbela involve somewhat greater use of foreign exchange and somewhat less use of locally available fuels.

TABLE 4

TARBELA WITHOUT INTERCONNECTION
(Tarbela Drawdown Level: 1332 feet)

	NORTHERN GRID					MARI			KARACHI - HYDERABAD		
	System Additions	Thermal Capab. (mw)	Hydro. Capab. (mw)	Total Capab. (mw)	Peak Load (mw)	System Additions	Capability (mw)	Peak Load (mw)	System Additions	Capability (mw)	Peak Load (mw)
1966	Existing	302	165	467	513 (Oct)	Existing	50	11 (Oct)	Existing	280	194 (Dec)
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	302	155	457	513 (Jan)		50	17 (Oct)	Hyderabad S2 (15) Kotri OFT (12)	307	225 (Oct)
1968	Lahore GT 2 (26) Lahore GT 3 (26)	478	265	743	598 (Mar)		50	22 (Oct)	Kotri GT (40)	347	271 (Oct)
1969	Mangla 3 (45)	478	310	788	690 (Mar)		50	29 (Oct)	Korangi 3 (125)	472	321 (Oct)
1970	Mangla 4 (45) Lyallpur P1 (100)	578	355	933	813 (Mar)	Mari 1 (100)	150	45 (Oct)	Hyderabad GT 2 (26)	498	382 (Oct)
1971	Lyallpur P2 (100) Retire: LYA S (10) MONT S (5)	663	355	1018	909 (Mar)		150	54 (Oct)	Karachi N1 (25) Korangi 4 (125)	648	442 (Oct)
1972	Lyallpur P3 (100)	763	355	1118	1004 (Mar)		150	65 (Oct)	Karachi N1 (100)	748	514 (Oct)
1973	Mangla 5 & 6 (90)	763	445	1208	1099 (Mar)		150	76 (Oct)	Retire: KAR A (15)	733	600 (Oct)
1974	Lyallpur P3 (100)	863	445	1308	1196 (Mar)		150	89 (Oct)	Korangi 5 (200)	933	692 (Oct)
1975	Tarbela 1 & 2 (180)	863	625	1488	1306 (Mar)		150	105 (Oct)		933	795 (Oct)
1976	Tarbela 3 & 4 (180)	863	805	1668	1394 (Mar)	Mari 6 (200)	350	115 (Oct)	Korangi 6 (200)	1133	889 (Oct)
1977		863	805	1668	1493 (Mar)		350	126 (Oct)		1133	998 (Oct)
1978	Mangla 7 & 8 (90)	863	895	1758	1601 (Mar)		350	137 (Oct)	Korangi 7 (300)	1433	1101 (Oct)
1979	Critical changes to May Warsak 5 & 6 (80)	863	977	1840	1671 (May)		350	148 (Oct)		1433	1234 (Oct)
1980	Lyallpur 5 (150)	1013	977	1990	1813 (May)		350	162 (Oct)	Korangi 6a (200)	1633	1370 (Oct)
1981	Tarbela 5 & 6 (146)	1013	1123	2136	1951 (May)		350	178 (Oct)	KAR N 3 (400)	2033	1499 (Oct)
1982	Tarbela 7 & 8 (146)	1013	1269	2282	2095 (May)		350	193 (Oct)		2033	1642 (Oct)
1983	Lyallpur 6 (200)	1213	1269	2482	2248 (May)		350	210 (Oct)	KAR N 4 (400)	2433	1799 (Sept)
1984	Tarbela 9 & 10 (146)	1213	1415	2628	2398 (May)		350	229 (Oct)		2433	1971 (Aug)
1985	Tarbela 11 & 12 (146)	1213	1561	2774	2567 (May)		350	250 (Oct)		2433	2154 (Aug)

TABLE 5

TARBELA WITH INTERCONNECTION
(Drawdown Levels: Tarbela 1332', Mangla 1040')

	NORTHERN GRID				PEAK LOADS			MARI		HYDERABAD - KARACHI		Cumulative Total Sys. Capability
	System Additions	Thermal Capab. (mw)	Hydro Capab. (mw)	Total Capab. (mw)	North	Mari	South	System Additions	Capa-bility (mw)	System Additions	Capa-bility (mw)	
1966	Existing	302	165	467	513 (Oct)	11 (Oct)	194 (Dec)	Existing	50	Existing	280	
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	302	155	457	513 (Jan)	17 (Oct)	225 (Oct)		50	Hyderabad S2 (15) Kotri OFT (12)	307	
1968	Lahore GT 2 (26) Lahore GT 3 (26)	478	265	743	598 (Mar)	22 (Oct)	271 (Oct)		50	Kotri GT (40)	347	
1969	Mangla 3 (45)	478	310	788	690 (Mar)	29 (Oct)	321 (Oct)		50	Korangi 3 (125)	472	
1970	Mangla 4 (45) Mangla 5 & 6 (90)	478	445	923	813 (Mar)	45 (Oct)	382 (Oct)	Mari S1 (100)	150	Hyderabad GT 2 (26)	498	
1971	Interconnect w. Mari (380 Kv) Retire: LYA S (10) MONT S (5)	463	445	908		1334 (Mar)		Interconnect w. N & S. Mari S 2 (100)	250	Interconnect w. Mari (380 kv) Karachi N 1 (25)	523	1681
1972		463	445	908		1501 (Mar)			250	Karachi N1 (100)	623	1781
1973	Mangla 7 & 8 (90)	463	535	998		1688 (Mar)			250	Retire: KAR A (15)	608	1856
1974		463	535	998		1877 (Mar)		Mari P (200)	450		608	2056
1975	Tarbela 1 & 2 (180)	463	715	1178		2093 (Mar)			450	Korangi 4 (125)	733	2361
1976	Tarbela 3 & 4 (180)	463	895	1358		2268 (Mar)		Second interconnex. w.S.	450	Second interconnexion with Mari	733	2541
1977		463	895	1358		2475 (Mar)		Mari S 6 (200)	650		733	2741
1978	Critical changes to May Tarbela 5 & 6 (146) Warsak (80) 2nd interconnex. w. Mari	463	1123	1586		2712 (May)		Second interconnex. w.N.	650		733	2969
1979	Tarbela 7 & 8 (146)	463	1269	1732		2966 (May)			650	Korangi 5 (200)	933	3315
1980	Tarbela 9 & 10 (146) Tarbela 11 & 12 (146) 3rd interconn. w. Mari	463	1561	2024		3250 (May)		3rd interconn. w. N.	650		933	3607
1981		463	1561	2024		3524 (May)			650	Korangi 7 (300)	1233	3907
1982	Lyallpur 6 (200)	663	1561	2224		3818 (May)		Mari S 7 (200)	850		1233	4307
1983		663	1561	2224		4165 (May)			850	Karachi N 3 (400)	1633	4707
1984		663	1561	2224		4494 (May)		Mari S 9 (300)	1150		1633	5007
1985		663	1561	2224		4864 (May)			1150	Karachi N4 (400)	2033	5407

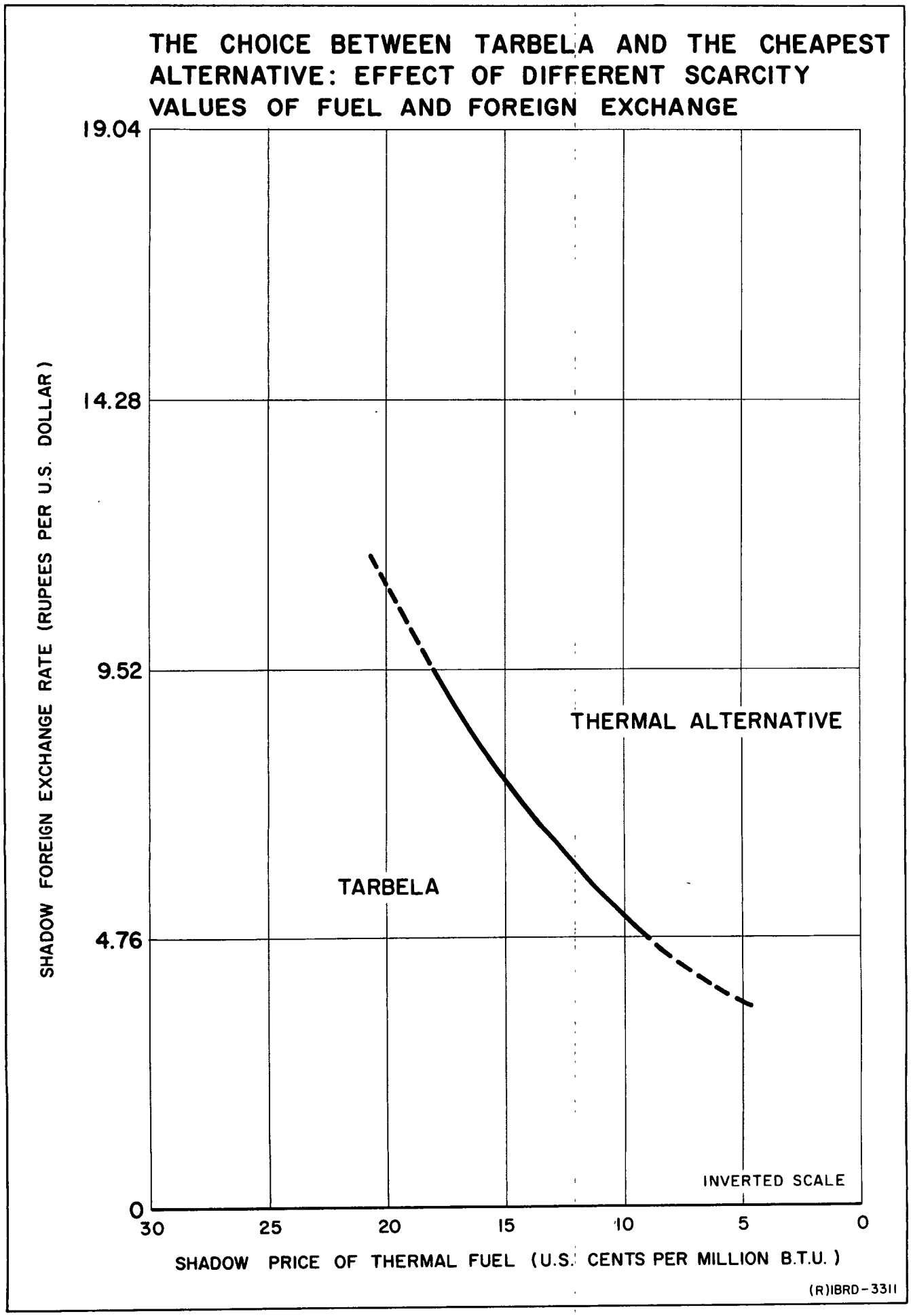
But this would be misleading as a final conclusion for fuel reserves are in many ways like a special portion of foreign exchange reserves: while they last they save on foreign exchange (and the great expansion in domestic fuel production in West Pakistan in the last ten years has resulted in large savings of foreign exchange) but when they are exhausted then foreign exchange must again be spent on fuel. When we attempt to go beyond the present apparent abundance of gas in West Pakistan and take this foreign exchange aspect of domestic fuel reserves into account, then the balance swings the other way and the estimate of Tarbela benefits made at current fuel prices seems less than what it should be. The more reasonable estimate of the benefits on the basis of the wider view of the foreign exchange problem, therefore, appears to be something of the order of the $160 million cited on page 9.

Figure 3 represents a decision-map with regard to Tarbela -- or a plot of the combinations of shadow foreign exchange rates and shadow fuel prices at which Tarbela becomes preferable to a thermal (or Kunhar) alternative. It is based on the data presented in Figure 2 and upon the results of an additional calculation undertaken with a shadow foreign exchange rate of 1.6 times the current rate of PRs 4.76 to the dollar (i.e. PRs 7.6 per U.S. dollar). The dashed lines represent extrapolations of the curve indicated by these three sets of calculations. The Figure indicates that at the current foreign exchange rate a program including Tarbela is preferable to the cheapest alternative at thermal fuel prices above 9 cents per million Btu, while at double the current exchange rate a program with Tarbela is preferable to the cheapest alternative at any fuel price above about 18 cents per million Btu. The Figure also indicates the sensitivity of the preference for Tarbela to changes in assumption regarding the foreign exchange rate.

The subject of interconnection is discussed at length in Annex 9, but it is clear from Figure 2 that the mere appearance of Tarbela on the system is scarcely sufficient by itself to justify interconnection. It must be recalled that the costs of the programs cited here do not include the costs of pipelines needed to carry fuel to the market; and all fuel is priced uniformly wherever it is used. On this basis, the programs which include Tarbela with interconnection have only a very slight edge on programs without interconnection. However, these simple figures do show that the advantage of interconnection tends to be greater the higher the value attached to fuel. This tendency is in line with what might be expected: the greater the value of fuel the greater advantage there is in saving thermal fuel by widening the market for hydro energy.

A Second Approach: The Timing of Tarbela

The results shown in the last paragraphs, while they are derived for a program which includes Tarbela in 1975, do not show specifically what would be lost or gained by completion of Tarbela in 1975 rather than a few years later. They are useful in that they represent a recomputation in terms of economic prices of the benefits of Tarbela using much the same concept of benefits as was used by the power consultant in his 1964 report


THE CHOICE BETWEEN TARBELA AND THE CHEAPEST ALTERNATIVE: EFFECT OF DIFFERENT SCARCITY VALUES OF FUEL AND FOREIGN EXCHANGE
19.04
14.28
9.52
4.76
0
SHADOW FOREIGN EXCHANGE RATE (RUPEES PER U.S. DOLLAR)
THERMAL ALTERNATIVE
TARBELA
INVERTED SCALE
30
25
20
15
10
5
0
SHADOW PRICE OF THERMAL FUEL (U.S. CENTS PER MILLION B.T.U.)
(R)IBRD-3311

on Tarbela. They are therefore comparable with these benefits and they are relevant for comparisons such as that between a joint stored water and power program involving Tarbela and an alternative involving, say, the Kalabagh-with-sluicing scheme.

For an investigation of the correct timing of the Tarbela Project, on the other hand, more explicit consideration has to be given to the time-path of scarcity values of inputs, particularly fuel, and to the exact alternative means of meeting irrigation requirements -- as well as power requirements. A reasonable degree of postponement for purposes of this type of analysis seemed to be about ten years -- not so long as to exaggerate what could be lost by a certain postponement and not so short as to be meaningless, given the rather rough analytical tools at our disposal. Therefore, the following comparison is between a program involving completion of Tarbela Dam in 1975 and one involving its completion in 1985. The alternatives on the irrigation side are discussed in detail in Part II of the Economic Annex to this report which covers the linear programming exercise. However, the main effects of a postponement of Tarbela from both the irrigation and the power points of view may be summarized here as follows:

(a) A very much larger draft on the Province's reserves of natural gas for purposes of power generation between now and 1985: about 1.57 trillion Btu for a program including postponed Tarbela against about 0.87 trillion Btu for a program with Tarbela in 1975. This results largely from the fact that, given the scarcity prices of fuel indicated in Annex 5 for the period 1975-85, the assumption that Tarbela would anyway be coming on line in 1985 and the above analysis of the breakeven fuel prices at which Kunhar becomes attractive as an alternative to Tarbela, the power program for the 1975-85 period in the absence of Tarbela would be heavily thermal, consisting mainly of plants fired by Sui or Mari gas.

(b) Loss of rabi irrigation supplies from Tarbela's live storage in the period 1975-85, a loss which it may be possible to make up by raising the Mangla Dam at an early date, by bringing in Sehwan-Manchar early and by installing deeper wells in fresh groundwater areas which would be able to mine the groundwater aquifer; this would result in lowering the groundwater table about 35 feet beyond what would be the case with the irrigation and agriculture consultant's balanced recharge criterion for tubewell pumping. These changes in the irrigation program would have effects upon the power program -- the change in the full supply level and live storage capacity of Mangla affecting the power capability of Mangla in the various months of the year, and the over-pumping adding to the power load particularly in certain months of the rabi season.

(c) Additional to the loss of the rabi irrigation supplies, provided by Tarbela's interseasonal storage capability would be a loss of Tarbela's intraseasonal regulation capability for ten years. It is hard to quantify this regulation capability because its actual importance will depend so much on the precise monthly and weekly pattern of

irrigation requirements that develops and on the natural river flows actually experienced in the year in question, but it has been estimated that the amount of intraseasonal regulation provided by Tarbela during the rabi period of water shortage (November-April) would average about 1.8 MAF per year over the period 1975-85. This intraseasonal regulation capability provided by main-stem storage under mean-year conditions is approximately equal to the combined regulation capability of Sehwan-Manchar and Chasma. Allowance is made in the irrigation program for the loss of Tarbela's regulation capability by bringing in Sehwan-Manchar earlier than would be necessary simply to meet stored water requirements.

(d) Tarbela storage releases would add to the annual recharge of the aquifer and this recharge would be valuable in areas of fresh groundwater where it could be recovered by tubewells during the scarce-water period. However, this recharge would be largely compensated by provision of direct irrigation supplies from other sources (as outlined above) sufficient to compensate for the loss of Tarbela water. If Tarbela were built in 1975 then the live storage available in Tarbela (after allowance for sedimentation) would by 1985 be about 7.4 MAF, assuming a drawdown level of 1332 feet. On the IACA release pattern, availability of stored water during the November-April period would be about 95 percent of this or 7.05 MAF. The alternative sources mentioned under (b) above would make up an equivalent amount (calculated in rim-station equivalents): Raised Mangla (3.18 MAF), Sehwan-Manchar (2.10 MAF), and Overpumping (1.80 MAF). Provision of these rabi supplies would thus compensate for most of the valuable recharge that would have been provided by Tarbela releases.

Alternative Joint Storage/Power Programs

Thus it is possible to build up two alternative storage and power programs for the period 1965-2000, one including Tarbela in 1975, the other Tarbela in 1985, and both meeting projected requirements of irrigation water and electric power. The alternative power program, given in detail below, would, according to our studies, serve to meet projected power loads including the overpumping requirements while the alternative irrigation program would, according to the linear programming analysis, make it possible for West Pakistan to attain the same gross value of agricultural output in the reference years 1975 and 1985 as was found to be attainable with the completion of Tarbela by 1975. The following tables summarize the costs of the alternative programs.

Table 7

Cost of Irrigation Program Including Tarbela 1975
(US$ million Present Worth at 8%)

		Current Exchange Rate ($1 = PRs 4.76)	Shadow Exchange Rate ($1 = PRs 9.52)
1975	Tarbela Dam	385	616
1980	Sehwan-Manchar	70	112
1988	Raised Mangla	34	54
		489	782

Low Mangla and Chasma are not explicitly mentioned in these programs because Mangla is already close to completion and Chasma is common to all programs; so that neither would affect the comparison. The cost estimates of the storage projects included have been taken from the latest Gibb report on the Tarbela Project. 1/ The figure included for overpumping in the postponed Tarbela program is based on the assumption that the IACA target for tubewell installation between 1966 and 1975 of about 20,000 public tubewells will be achieved, though the location of some of the wells has been rearranged in order to establish by 1975 an overall pattern of tubewells better adapted to a situation in which Tarbela would not be completed until 1985.

Table 8

Irrigation Program Including Tarbela 1985
(US$ million Present Worth at 8%)

	Current Exchange Rate ($1 = PRs 4.76)	Shadow Exchange Rate ($1 = PRs 9.52)
1975 Raised Mangla	93	148
1975 Sehwan-Manchar	98	164
1985 Tarbela	179	286
1975-85 Overpumping	102	116
	472	714

Of the two power programs needed for this comparison, one was the program including Tarbela in 1975 and including systemwide interconnection in 1971 as shown in Table 5, while the other was specially designed to be fully complementary with the irrigation storage program outlined in Table 8. Apart from the additional thermal capability required to make up for the absence of Tarbela, complementarity required two other important changes. First the load forecast for the later years had to be raised to cover the additional amounts of power required, both for pumping more water in the rabi season to make up for the lack of Tarbela and for pumping from a greater depth throughout the year as a result of lowering the water table. It was estimated that this might total about 280 million kwh (including distribution losses) in 1980 and about 550 million kwh (including losses) in 1985. This additional energy requirement was distributed over the canal commands where overpumping would be undertaken for supply of irrigation water from the groundwater aquifer. Monthly energy requirements were converted into peak loads by a 70 percent load factor -- being about the average of the monthly load factors implied in the pumping load forecasts made by the Bank's consultants for the Northern Grid area in 1985. To err on the conservative side in assessment of the additional load no allowance was made for interruption of the tubewell load. The result of these calculations was an addition to peak load in the critical months of March and May of 60 mw and 34 mw respectively in 1980, and of 120 mw and 65 mw respectively in 1985.

1/ Sir Alexander Gibb & Partners, "The Tarbela Project", London, November, 1966.

The second major change in the power program required for complementarity, with the alternative irrigation program was allowance for the change in capabilities at Mangla that would result from raising it, and at the same time adjustment of the rule curve for the operation of the reservoir to a pattern that would be appropriate for a situation where some Mangla storage was being used to supply canal commands that would otherwise have been fed from the Indus. The basic approach was to develop a release pattern that was a combination of the agricultural consultant's release pattern for Mangla (applied to the 4.8 MAF live storage of Low Mangla, with drawdown level of 1040 feet) and the agricultural consultant's release pattern for Tarbela (applied to the 3.5 MAF live storage that would be added by the raising of Mangla). Adjustments had to be made, particularly during the filling period, to ensure that the outflow through the dam during this period would at least be sufficient to meet the kharif irrigation requirements of the Jhelum-fed canal commands. The rule curve finally adopted for the study was one that would provide sufficient kharif irrigation water in a mean year and at the same time fill most of the reservoir by early August. Storing such a large proportion of flows in June and July meant that energy available in those months was severely curtailed. In years of low summer flow, filling of the reservoir would have to be slower, which would mean that the capability would not increase as rapidly between the time of maximum drawdown (early May) and the end of the kharif season (September). Nevertheless, there seems to be little doubt, if the assumptions regarding irrigation requirements made by IACA are correct, that High Mangla could be filled, while at the same time the 1985 kharif requirements of the Jhelum-fed canal commands 1/ were met, except, possibly, in years such as 1940 when kharif flows on both the Chenab and the Jhelum were unusually low. Annex 6, Appendix I-Table 9 shows the mean-year monthly patterns of capability and energy for eight units at Raised Mangla that were used for purposes of this analysis.

As regards investment in the power sector, postponement of Tarbela from 1975 to 1985 would require installation of about 4,300 mw of new thermal capacity between 1966 and 1985 -- or about 1,100 mw more than the program with Tarbela in 1975. The generation program modeled around delayed Tarbela is shown in Table 9. The majority of the additional capability required would be straight replacement of the Tarbela units (capability of 12 units with a 1332-foot drawdown level is about 875 mw in the critical period on the system), but part of it would also be (i) to meet the additional overpumping load, (ii) to cover the additional reserve requirements of thermal capability (12 percent reserves on thermal equipment as against 5 percent on hydro equipment), and (iii) to provide the additional reserves required if the system remained without interconnection.

With regard to the last point attention was given to the question of whether, if Tarbela were expected in 1985, it would be

1/ As estimated by irrigation and agriculture consultants. See IACA, Comprehensive Report, Volume 5, Annexure 7 - Water Supply and Distribution, p.94.

preferable to introduce EHV transmission earlier and concentrate the requisite additional thermal capacity in the interim at Mari/Sui, or whether it would be better to build additional gas pipeline capacity from Sui and maintain the independence of the three main power markets. Inclusion of early interconnection in the program with postponed Tarbela would make possible some fuel savings as a result of providing a wider market for Mangla energy and it would enable the Tarbela units to be brought in more rapidly than would otherwise be the case after 1985; on the other hand, it would eliminate a sizeable part of the potential saving in capital costs that postponement of Tarbela could make possible. In fact, by 1985 loads in the North will, according to our load forecast, be large enough and they will be growing rapidly enough that the output of the 12 Tarbela units could be almost fully absorbed within the North alone within about five years. Rough calculations to take account of these points, and of the saving in gas pipeline capacity and reserve generating capability that would be possible with interconnection, suggested that it would be economically preferable to eliminate interconnection altogether if Tarbela were not available until 1985.

Table 9

Power Development Program for Northern Grid with Tarbela Postponed to 1985
(Mari and South as in Table 4, "Tarbela without Interconnection")

	System Additions		Thermal Capability (mw)	Hydro Capability (mw)	Total Capability (mw)	Peak Load (mw)
1966	Existing		302	165	467	513 (Oct)
1967	Lyallpur S 1	(124)	302	155	457	513 (Jan)
	Mangla 1 & 2	(90)				
1968	Lahore GT 2	(26)	478	265	743	598 (Mar)
	Lahore GT 3	(26)				
1969	Mangla 3	(45)	478	310	788	690 (Mar)
1970	Mangla 4	(45)	578	355	933	813 (Mar)
	Lyallpur P	(100)				
1971	Lyallpur P 1	(100)	663	355	1018	909 (Mar)
	Retire	(15)				
1972	Mangla 5 & 6	(90)	663	445	1108	1004 (Mar)
1973	Lyallpur P 2	(100)	763	445	1208	1099 (Mar)
1974	Mangla 7 & 8	(90)	763	535	1298	1196 (Mar)
1975	Raised Mangla		763	685	1448	1227 (May)
1976			763	685	1448	1334 (May)
1977	Warsak 5 & 6 (w/o re-reg.)		863	825	1688	1520 (Mar)
	Lyallpur 3	(100)				
1978	Lyallpur 4	(100)	963	825	1788	1641 (Mar)
1979	Lyallpur 5	(150)	1113	825	1938	1758 (Mar)
1980	Lyallpur 5a	(150)	1263	765	2028	1847 (May)
1981	Lyallpur 6	(200)	1463	765	2228	1991 (May)
1982	Lyallpur 6a	(200)	1663	765	2428	2140 (May)
1983	Lyallpur 7	(200)	1863	765	2628	2300 (May)
1984	Lyallpur 7a	(200)	2063	765	2828	2455 (May)
1985	Lyallpur 5b	(150)	2213	765	2978	2632 (May)

These calculations regarding interconnection, like the other calculations concerning the timing of Tarbela, were conducted in terms of the economic fuel prices developed in Annex 5 specifically for the two cases -- of Tarbela in 1975 and Tarbela in 1985. Use of the economic fuel prices, in conjunction with the assumption that interconnection would not be introduced in the postponed Tarbela case, required that an allowance be made for the capital and operating costs of gas pipeline capacity needed to carry the gas from Sui to the power markets. Analysis of the pattern of fuel requirements in the Northern Grid area in the case with postponed Tarbela suggested that, if all fuel requirements were to be met from gas, the annual load factor on the gas pipeline supplying the thermal plants would be quite high -- about 85 percent in 1984, for instance. The cheapest way of making sufficient fuel available would therefore probably be, as far as can now be foreseen, to provide enough gas pipeline capacity to meet peak-day requirements. Without Tarbela in 1975, peak-day requirements of gas for thermal generation in the Northern Grid would rise from 75 MMcf in 1967 to about 80 MMcf in 1971 and 100 MMcf in 1976 (quite slowly because most capacity additions through this period would be hydro units). Peak-day requirements would rise more rapidly after 1976 to about 200 MMcf in 1981 and above 300 MMcf by 1985. With Tarbela in 1975 peak-day requirements for thermal fuel would not rise above about 100 MMcf at any time through the 20-year Plan period (see Annex 9 App.II for methods of calculating peak and average day gas requirements). It is possible to make a rough estimate of the cost of providing this additional 200 MMcf per day of pipeline capacity, required by the program with postponed Tarbela, on the basis of the latest expansion plan prepared by the company responsible for the Sui-Multan-Lyallpur gas pipeline, Sui Northern Gas Pipelines Limited. 1/ It would appear that the total economic cost involved in providing loops and compression sufficient to meet this additional peak-day requirement would be in the neighborhood of $26 million, with a present worth of about $8 million at the current foreign exchange rate, and about $13 million at the shadow foreign exchange rate.

In addition to these pipeline investment costs there would also be certain smaller amounts involved in provision of additional gas purification facilities at Sui and in the operation and maintenance of these various gas facilities.

Gas pipeline requirements for the South would be about the same as required under the 'without interconnection' case discussed in Annex 9. Peak-day gas requirements of the power programs with early Tarbela and with delayed Tarbela would start to diverge significantly about 1971/72 and the peak-day requirements of the program with delayed Tarbela would rise to over 200 MMcf in the late 1970's (i.e. before the major nuclear plants came in in the early 1980's), while those of the program with early Tarbela would scarcely rise above 100 MMcf throughout the planning

1/ Sui Northern Gas Pipelines Limited, Appraisal No.3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966). This plan is discussed further in Annex 9 below.

period and would generally be substantially lower. The economic cost of providing pipeline capacity to cope with the additional peak is estimated in Annex 9 at about $23 million; the discounted present worth of these costs, together with the operation and maintenance costs for the pipeline, is estimated there at about $12 million at the current foreign exchange rate and $18 million at the higher foreign exchange rate. As pointed out in Annex 9, if it proves possible to develop the Sari Sing field for gas storage the differential between the two programs, in cost of facilities for making gas available to meet all thermal fuel requirements, would be somewhat greater because the difference between average-day fuel requirements of the two programs is greater than the difference between peak-day fuel requirements.

Table 10 shows the total system costs of the alternative power programs, including the pipeline costs just discussed, discounted to 1965. The costs shown in the table cover all capital and maintenance and operating costs of power generation and transmission for 1966-85, together with fuel requirements valued according to the prices developed in Annex 5; they also cover the major differences in capital costs and fuel costs that would be involved in the period 1985-95 as a result of bringing in the Tarbela units in the years following 1985 instead of 1975-80. The costs are shown for the different assumptions with regard to the foreign exchange rate used in this report and for the different assumptions regarding fuel reserves (and hence fuel prices) described in Annex 5.

Table 10

Present-Worth Costs of Power Programs
Including Tarbela in 1975 and in 1985
($ million discounted at 8% to 1965, economic fuel prices)

	Current Est. Gas Reserves		Larger Gas Reserves	
	Current Exchange Rate	Shadow Exchange Rate	Current Exchange Rate	Shadow Exchange Rate
Tarbela 1975	795	1,104	674	983
Tarbela 1985	915	1,220	767	1,072
Costs of 10-year Postponement	120	116	93	89

It is possible to indicate briefly the main components of the cost of postponement. The difference between the present-worth costs of the two programs, when foreign exchange is valued at the current scarcity price and fuel at the price series appropriate on the basis of current estimates of gas reserves, is indicated in the above table to be $116 million. In terms of the capital costs of generation and transmission over the period 1966-85 (with the foreign component valued at this higher exchange rate) the program with Tarbela in 1985 actually shows a substantial saving of about $110 million over the program with early Tarbela. The cost of additional thermal capacity required to make up for lack of Tarbela in 1975-85 is much more than outweighed by the capital cost savings obtained

by eliminating the need for the EHV transmission system and by postponing the Tarbela units. The total costs involved in the construction and operation of the amount of gas pipeline capacity required for the postponed Tarbela program are estimated at about $35 million in present-worth terms, reducing the net capital cost saving over the period 1966-85 to about $75 million. And this saving is much more than offset by the combined effect of the additional fuel costs involved -- about $155 million, two-thirds of it in the 1975-85 period -- and the additional capital cost of about $36 million involved for the postponed Tarbela program after 1985, by installing the Tarbela units instead of thermal units at that time. Thus, in summary, the net saving in capital costs over the whole period 1965-95 resulting from postponement of Tarbela is of the order of $40 million, and this is more than outweighed by the extra fuel costs of about $155 million incurred by such a postponement. Of these extra fuel costs about 70 percent is due to the extra quantity of thermal fuel required and about 30 percent due to the higher average price at which the fuel for the program with delayed Tarbela is costed here.

It is noteworthy how these figures for the benefits of having Tarbela early rather than late are much less sensitive to the foreign exchange rate used than were the estimates of the benefits of Tarbela given earlier on the basis of financial fuel prices and of fuel prices that were uniform throughout the Province and throughout the years of the planning period. The difference arises mainly as a result of the special approach to fuel pricing adopted in this analysis. The main alternative to Tarbela studied here as elsewhere is thermal equipment which is much cheaper in terms of capital cost, and hence in its direct foreign exchange component, but expensive in terms of the fuel it consumes. In the previous analyses indigenous fuel was treated as a purely domestic cost item so that comparison of programs with and without Tarbela showed significantly lower benefits to Tarbela when foreign costs were valued at an exchange rate higher than the official one. Here, however, fuel has been treated more like a foreign resource in that its price has been made to depend on the foreign exchange burden of importing fuel when known domestic fuel resources are exhausted. The heavier fuel consumption of the 'without Tarbela' (or in this analysis 'with postponed Tarbela') case weighs more heavily against it.

Present-Worth Costs of Alternative Joint Programs

The present-worth costs of the irrigation and complementary power programs developed in the preceding pages may now be brought together (see Table 10(a)).

These figures suggest that, at an economic fuel price based on the present 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 $50 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 $20 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 saving in the irrigation

program from postponement of Tarbela is very small and the loss to power from postponement remains large. These results are chiefly due to 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.

Table 10(a)

Present-Worth Costs of Surface Storage/Power Programs
Including Tarbela in 1975 or 1985
($ million discounted at 8% to 1965, economic fuel prices)

	Current Estimated Gas Reserves		Larger Gas Reserves	
	Current Exchange Rate	Shadow Exchange Rate	Current Exchange Rate	Shadow Exchange Rate
Tarbela 1975				
Surface Storage Program a/	489	782	489	782
Power Program	795	1,104	674	983
	1,284	1,886	1,163	1,765
Tarbela 1985				
Surface Storage a/ b/	472	714	472	714
Power Program	915	1,220	767	1,072
	1,387	1,934	1,239	1,786
Saving attributable to completion of Tarbela in 1975 instead of 1985	103	48	76	21

a/ Including all costs of main reservoir structures.
b/ Including some overpumping to compensate for lack of Tarbela.

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 could and would be implemented. The Bank Group believes that the alternative program is sufficiently valid as an alternative to be used in the economic evaluation of a postponement of Tarbela. Many of its components, such as High Mangla and the public tubewell schemes have received considerable study in Pakistan. In combination they appear, in a preliminary way at least, to 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 assumed kharif flows would have apparently 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, even on assumptions other than those used by IACA, it appears to be 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 -- the extensive public tubewell fields will

provide a sizeable amount of flexibility for coping with years of low flow.

While the Bank Group thinks that the alternative storage and power program is technically reasonable for purposes of economic comparison, it does 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 extremely 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 or nine years later. In the second place, the project is inherently so large in its contribution to power supplies and to irrigation supplies that it provides a substantial margin for meeting unanticipated growth in demand.

In sum, then, the Bank Group believes that the figure of $50 million, in present-worth terms, is a reasonable valuation of the savings to be had from completing Tarbela in 1975 rather than in 1985, except for 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, say, five or six years -- resulting from delays in final selection and financing of any coordinated program could result in much larger loss of benefits.

The Drawdown Level at Tarbela

By sacrificing about 600,000-700,000 acre-feet of live storage capacity and keeping the minimum reservoir level up to 1332 feet instead of the minimum design level of 1300 feet, the firm capability of twelve units at Tarbela can be increased by about 270 mw. 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, early filling of Mangla Reservoir will increase the capability there 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 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-foot drawdown level instead of 1300 feet will be about 230 mw. Maintenance of such a drawdown level would also add substantially to the energy available

from Tarbela in the critical period April-July at the end of rabi and beginning of the filling period; it would reduce the available energy slightly in the winter months November-March as a result of reduced releases. The net effect on the total amount of energy annually available from Tarbela with twelve units under mean-year conditions would be a slight increase from about 12,800 million kwh to about 13,100 million kwh.

The full 230 mw of additional capacity available with a drawdown level of 1332 feet as opposed to 1300 feet will of course only become available when all twelve units are installed at Tarbela. In the intervening period the advantage of the higher drawdown level will be reaped in the form of some postponement of the need for investment in additional capacity. Once twelve units are installed the saving in thermal capacity will be of the order of 250 mw, since firm hydro capacity requires somewhat lower percentage reserves than thermal capacity to provide the same degree of security of supply.

Several programs were analyzed using the computer simulation model with Tarbela at drawdown levels of 1332 feet and 1300 feet. Table 11 gives partial details of four of them, focusing entirely on the differences brought about by the different drawdown levels. All are sub-optimal in the sense that they would be improved by some rescheduling of the units. However, they are adequate for indicating the relative merits, from the power point of view, of maintaining a higher or lower drawdown level over the years 1975-85. On the left hand side of Table 11 are two programs without interconnection and with a consequent delayed phasing of the Tarbela units. In order to meet the Northern Grid load additional thermal capacity is needed in the case with 1300 feet drawdown level, adding up to about 300 mw by 1985. On the right hand side of the table are two programs with interconnection. They should not be compared with those on the right for indicating the value of interconnection since they differ in other ways besides, in particular by including Kunhar at an earlier date than would likely be economically justifiable under foreseeable circumstances with regard to fuel. However, the two 'with interconnection' programs give a sound indication of the type of differences that would occur as a result of maintaining different drawdown levels at Tarbela in a power development program which included Province-wide interconnection. Because each Tarbela unit has a greater capability in the critical month with the higher drawdown level the units can be brought in somewhat more slowly under those circumstances. Optimal scheduling would almost certainly further lengthen out the addition of units at Tarbela to permit absorption of more of their energy immediately they are constructed. Nevertheless, the existence of interconnection would make it worthwhile to bring in the hydro units more quickly than would otherwise be the case. Less additional thermal capability is again required in the 'with interconnection' programs when Tarbela is held at 1332 feet than when it is drawn down to 1300 feet.

Table 11 - Programs with Alternative Tarbela Drawdown Levels

	Without Interconnection					With Interconnection a/				
	Tarbela 1300'		Tarbela 1332'			Tarbela 1300'		Tarbela 1332'		
	System Additions	System Capab. (mw)	System Additions	System Capab. (mw)	Northern Peak (mw)	System Additions	System Capab. (mw)	System Additions	System Capab. (mw)	Provincial Peak (mw)
1975	Existing Tarbela 1&2(160)	1308 1468	Existing Tarbela 1&2(180)	1308 1488	1306(Mar)	Existing Tarbela 1&2(160)	2181 2341	Existing Tarbela 1&2(180)	2181 2361	2093(Mar))
1976	Tarbela 3&4(160)	1628	Tarbela 3&4(180)	1668	1394(Mar)	Critical changes to May Tarbela 3&4(108)	2467	Critical changes to May Tarbela 3&4(146)	2543	2243(May)
1977	Lyallpur 5(150)	1778		1668	1493(Mar)	Tarbela 5&6(108) Korangi 5(200)	2775	Warsak 5&6(80) Korangi 5(200)	2823	2463(May)
1978		1778	Mangla 7&8(90)	1758	1601(Mar)	Warsak 5&6(80) Tarbela 7&8(108)	2963	Tarbela 5&6(146)	2969	2712(May)
1979	Critical changes to May Warsak 5&6(80)	1824	Critical changes to May Warsak 5&6(80)	1840	1671(May)	Tarbela 9&10(108) Korangi 6(200)	3271	Tarbela 7&8(146) Korangi 6(200)	3315	2966(May)
1980	Mangla 7&8(90) Lyallpur 5a(150)	2064	Lyallpur 5(150)	1990	1813(May)	Tarbela 11&12(108) Kunhar 1(203)	3582	Tarbela 9&10(146) Tarbela 11&12(146)	3607	3250(May)
1981	Tarbela 5&6(108)	2172	Tarbela 5&6(146)	2136	1951(May)	Lyallpur 6(200) Korangi 7(300)	4082	Kunhar 1(203) Korangi 7(300)	4110	3524(May)
1982	Tarbela 7&8(108)	2280	Tarbela 7&8(146)	2282	2095(May)	Kunhar 2(101)	4183	Lyallpur 6(200)	4310	3818(May)
1983	Lyallpur 5b(150)	2430	Lyallpur 6(200)	2482	2248(May)	Kunhar 3(102) Karachi N3(400)	4685	Kunhar 2(101) Karachi N3(400)	4811	4165(May)
1984	Tarbela 9&10(108) Lyallpur 6(200)	2738	Tarbela 9&10(146)	2628	2398(May)	Kunhar 4(85) Lyallpur 7(200)	4970	Kunhar 3(102)	4913	4494(May)
1985	Tarbela 11&12(108)	2846	Tarbela 11&12(146)	2774	2567(May)	Karachi N4(400)	5370	Kunhar 4(85) Karachi N4(400)	5398	4864(May)
(1985	Total Thermal Cap.	1513		1213)		(Total thermal cap.	3546		3346)	

a/ Both these programs have the same transmission line scheduling:
1971 S/C 380-kv line Lyallpur-Mari-Karachi
1977 a duplicate of this line
1979 additional S/C 380-kv line Lyallpur-Mari

It is pointed out in Annex 6 that the benefits to power and to agriculture of drawing down the Tarbela Reservoir to one level rather than another are likely to fluctuate considerably over the years, depending primarily on the balance between demand and supply for water and for power then existing, and on the feasibility and cost of increasing supplies of each from alternative sources. It was also suggested that, as a result, best use of resources would only occur if the drawdown level was frequently reconsidered and modified to accord with the situation expected to obtain in any particular year or series of years. Because the situation regarding demand and supply of water and of power, and regarding the costs of providing more water or more power from alternative sources, will change frequently in an economy growing as dynamically as is implied by the water and power development programs recommended here, the series of years for which the drawdown level could wisely be set at some fixed level would be quite short.

The power programs outlined in Table 11 are based on the assumption that either the higher drawdown level or the lower one will be maintained through each year of the ten-year period, 1975-85. This period is certainly too long to be encompassed by one decision regarding the Tarbela drawdown level. Many changes will occur in the course of it. Initially, for instance, Tarbela will make available a rather large increase in supplies of rabi irrigation water; it will probably take some time for the farmers to absorb all of this increase and derive full benefits from it. Initially, in other words, the marginal value to agriculture of the 600,000-700,000 acre-feet of water lying between 1300 feet and 1332 feet will be relatively low. It should rise over the years -- but then, according to the proposed irrigation program, additional surface water will become available from Sehwan-Manchar (in 1980) and there will be a large tubewell field in existence which can make available additional supplies of irrigation water relatively cheaply and easily by overpumping. Moreover, according to the projection of the economic value of thermal fuel made in Annex 5, the sacrifice involved in using more of the natural gas reserves for power generation at this time will be increasing quite rapidly. Thus there are far too many uncertainties and too many divergent trends foreseeable in the decade 1975-85 to warrant making a decision now about a matter which, being a matter of operating policy, does not have to be decided until much nearer the time.

The purpose of comparing these alternative power programs and considering complementary long-run irrigation programs is rather to give an impression of the general order of priority that now seems likely to attach to the claims of agriculture and of power in the decade 1975-85. The figures given below for the present-worth costs of the various alternative power programs refer simply to the costs over the period 1965-85; no allowance is made for a terminal correction, precisely because the intention is to focus narrowly on the ten-year period of choice being considered here.

Table 12

Present-Worth Savings to Power from Operating Tarbela Reservoir to Drawdown 1332' rather than 1300' over the Period 1975-1985
(US$ million)

	Current Exchange Rate			Higher Exchange Rate		
	Financial Fuel Prices	All thermal fuel per million Btu		Financial Fuel Prices	All thermal fuel per million Btu	
		20¢	70¢		20¢	70¢
Total System Costs of Programs with Interconnection						
With Tarbela 1300'	579	543	653	901	865	975
With Tarbela 1332'	558	522	631	867	831	940
Saving of 1332' over 1300'	21	21	22	34	34	35
Total System Costs of Programs Without Interconnection						
With Tarbela 1300'	556	497	649	852	792	946
With Tarbela 1332'	539	481	630	823	766	916
Saving of 1332' over 1300'	17	16	19	29	26	30

The table indicates that the benefits to power of maintaining the higher drawdown level throughout the period 1975-85 are not very sensitive to changes in assumption regarding the cost of thermal fuel 1/ but are highly sensitive to changes in assumptions regarding the value of foreign exchange. This is logical in view of the fact that maintenance of the higher drawdown level adds little to the availability of useful energy from Tarbela but contributes significantly to the capability available in the critical period on the system. The saving resulting from maintenance of the higher drawdown level is largely a saving of investment in complementary thermal capacity; and such saving has an important 60-80 percent foreign exchange component.

The table suggests that, whatever the value attached to the economic parameters, the higher drawdown level is somewhat more valuable when the market for power is enlarged by systemwide interconnection. This is quite realistic in view of the facts that a portion of the benefit of the higher drawdown level is, so to speak, attached to each unit and that,

1/ The lower array of figures gives a better impression of sensitivity to fuel price than the top array because the latter is based on comparison of programs which are so heavily hydro-based (including Kunhar) that the energy lost through drawing down Tarbela to 1300' rather than 1332' is mostly compensated by absorbing more Kunhar energy. They are, in effect, programs which implicitly assume that fuel is very costly (see discussion at beginning of this annex).

as pointed out, interconnection will make it worthwhile to introduce the units more quickly than would otherwise be the case. Earlier realization of the benefits will make for greater present worth. The very delayed phasing of the Tarbela units in the 'without interconnection' case thus means that the value attributed to the higher drawdown level in that comparison is a minimum estimate of the true value. On the other hand, the higher values resulting from the comparison of the 'with interconnection' cases result partly from the more rapid introduction of hydro units that interconnection will indeed make worthwhile, and partly from the fact that the next major addition to system capability following Tarbela is assumed in these programs to be the capital-intensive Kunhar Project so that even a slight postponement, such as is made possible by maintaining the higher drawdown level at Tarbela, results in significant savings. In fact, it does not seem likely that the fuel situation in the early 1980's will be sufficiently stringent to warrant bringing in Kunhar rapidly after completion of twelve units at Tarbela; it is more likely that additions to capability at this time would be further thermal units which are far less capital-intensive than Kunhar; maintenance of the higher drawdown level would make it possible to postpone them, but the savings so obtained would be significantly less than the savings obtainable by postponing Kunhar. For this reason, the present-worth values of the benefits of maintaining the higher drawdown level derived from this comparison of programs including Kunhar should be considered maximum estimates.

On the basis of these various considerations it would appear that the best estimate of the value to power of maintaining the higher drawdown level at Tarbela from 1975 to 1985 would be about $19 million at the current foreign exchange rate. 1/ This is the figure which is comparable with the estimate of agricultural benefits obtainable from releasing water down to 1300 feet each year which is derived from the shadow prices implicit in the Bank Group's linear programming analysis of agricultural investment. This linear programming analysis produces several figures. In the first place, if the restrictive assumptions are made that Tarbela will be the only addition to surface storage in the decade 1975-85 and that the tubewells will not pump more than balanced recharge in the mean year, then the value to agriculture of drawing down to 1300 feet rather than 1332 feet each year can be taken as the marginal benefits to agriculture which would accrue from adding 600,000-700,000 acre-feet of water to total rabi irrigation supplies each year; this is estimated at about $19 million in present-worth terms. But the linear program shows that this figure tends to exaggerate the advantages to agriculture of drawing down to 1300 feet in this period. First, it fails to take into account the extensive tubewell fields that will be in existence by this time on the recommended program and the consequent possibility of making marginal additions to irrigation supplies by means of overpumping. Under these conditions

1/ This is based on the assumption that, as recommended in Annex 9, the power system would be interconnected by 1975 so that the Tarbela units would be brought in quite rapidly.

the marginal benefit to agriculture of drawing down to 1300 feet rather than 1332 feet should be counted in terms of the alternative cost of providing the water by overpumping rather than in terms of the absolute benefits such water could produce; this results in a present-worth figure of about $11-15 million. Secondly, the above analysis failed to take into account the Sehwan-Manchar Project which the irrigation consultant recommended for completion by 1982. This project would add about 2.1 MAF rim-station equivalent to rabi irrigation supplies and therefore, if it were undertaken in 1982, it would substantially lower the marginal value of water released for agricultural purposes in the early 1980's.

Comparison of these figures of the power and agricultural benefits attaching to different drawdown levels suggests that there is a clear presumption in favor of operating Tarbela to a drawdown level of 1332 feet over the decade 1975-85. But, as pointed out, such a general prescription must in fact be checked, before actual operating decisions are made, on the basis of short periods of years. It is quite likely that there will be some years, for instance in the early part of the decade, when the drawdown level should be maintained higher than 1332 feet; this might enable the Tarbela units to be phased in a little more slowly than would otherwise be necessary. Equally there may be some years, e.g. just before Sehwan-Manchar is completed, when it would be justifiable to draw the reservoir down somewhat below 1332 feet. However, for purposes of preparing the power program recommended here, a normal operating level of 1332 feet has been assumed.

For the period after 1985 the critical factors affecting the decision regarding the drawdown level at Tarbela will be, again, the overall balance between supply and demand for irrigation water and for power as it exists at that time and the costs of the next projects in line for development of the irrigation system and the power system. Early completion of second-stage main-stem storage would tend to lower the marginal value of water for irrigation; while delay might mean that it would be preferable to draw down below 1332 feet. However, it appears that there will be two factors prompting maintenance of a higher drawdown level. In the first place, the pattern of siltation at Tarbela is expected to be such that the addition to irrigation supplies obtained by drawing down to 1300 feet rather than 1332 feet will be continuously decreasing. (See the discussion in Annex 6.) In the second place, as far as can now be foreseen, the economic value of thermal fuel consumed for power generation will be increasing through these years (see Annex 5).

The Scheduling of Installation of Units at Tarbela

A number of different power programs with different schedulings of the Tarbela units were constructed and tested on the power system simulation model. They suggested that the best schedule might be to bring in the first four units immediately following completion of the dam (i.e., two in 1975 and two in 1976) and to bring in the remaining eight units in 1978-80. The 'gap' between 1976 and 1978

would be filled with the two Warsak units (5 and 6) for peaking purposes and with a 200-mw steam unit in the Mari area. These results were built into the power program recommended.

These recommendations regarding the scheduling of the Tarbela units diverge somewhat from those made by Stone & Webster -- most importantly in envisaging installation of the last four units at Tarbela in 1980 instead of in 1982/83. Precise scheduling will of course depend on details of the growth of system loads and of the disposition of loads across the Province which are not foreseeable at the present time. Nevertheless, it is worth describing briefly one of the exercises which led the Bank Group to conclude in favor of early completion of Tarbela units 9-12 because it indicates the method adopted for reaching judgments regarding the scheduling of the other units and because it illustrates the use of the power system simulation model for this type of analysis.

In order to test the scheduling of Tarbela units 9-12, two power development programs were devised, identical in every way, except that one included Tarbela units 9-12 and the third Mari-Lyallpur EHV transmission line in 1980 and 300 mw of Mari thermal capability in 1984, while the other included the same items but in reverse order -- i.e., 300 mw of Mari thermal capability in 1980 and Tarbela units 9-12 together with the third Mari-Lyallpur EHV transmission line in 1984. The present-worth costs of these alternative power programs are shown in the following table. 1/

Table 13

Present-Worth Costs of Programs
With Tarbela Units 9-12 in 1980 or in 1984
(Million US$)

	Current Exchange Rate			Shadow Exchange Rate		
	Financial Fuel Prices	All thermal fuel per million Btu		Financial Fuel Prices	All thermal fuel per million Btu	
Program including:		20¢	70¢		20¢	70¢
Tarbela 9-12 in 1984	512	482	612	794	764	895
Tarbela 9-12 in 1980	509	479	597	794	764	883
Saving of Tarbela 9-12 in 1980 rather than in 1984	3	3	15	0	0	12

1/ These figures represent total system costs over the period 1966-85. No allowance has been made for a terminal correction because it would be identical in the two cases, the structure of assets at the end of the planning period being the same in each.

The savings attaching to completion of Tarbela units 9-12 in 1980 rather than in 1984 are greater the higher the price of thermal fuel and the lower the price of foreign exchange, as might be expected. At the current foreign exchange rate Tarbela units 9-12 in 1980 always appear preferable to the Mari units, within the range of fuel prices considered. At the higher foreign exchange rate there is little to choose at financial fuel prices or at low uniform prices for fuel. If the cost figures in the last two columns of Table 13 were drawn up on a graph similar to Figures 1 and 2 at the beginning of this annex, they would indicate increasing savings attaching to early scheduling of Tarbela units 9-12 as the fuel price increased from 20 cents to 70 cents per million Btu. The estimate of scarcity values of fuel developed in Annex 5 showed that, on the basis of current estimates of gas reserves, the economic price of gas at well-head in the early 1980's would be in the range of 30-35 cents per million Btu. At such a price it would clearly be preferable to have Tarbela units 9-12 in 1980 rather than 1984; the saving obtained would be in the order of $2 million. Therefore, these units were scheduled for 1980 in the program presented in Volume IV. However, if fuel reserves turn out to be larger than presently believed to be the case then the conclusion might be different. The lower set of fuel prices developed on the assumption of somewhat larger gas reserves in Annex 5 indicate a scarcity value for gas devoted to thermal generation in the order of 20 cents per million Btu in the 1980-83 period. The figures in Table 13 suggest that, with fuel available at that price, there would be no great advantage either to having the last Tarbela units in 1980 or to having them in 1984.

The conclusions outlined in the above paragraph were also tested, with the aid of the simulation model, under a number of other assumptions. For instance, the programs were examined to see if it was the presence of the third transmission line from Mari to Lyallpur in 1980 which made the earlier scheduling of the Tarbela units seem preferable. Various programs were run to examine different phasings of the transmission lines. The conclusion was drawn that, while there were advantages to having the third Mari-Lyallpur transmission line slightly earlier than recommended by Stone & Webster, this was not in fact the critical difference between the two programs with different schedulings of Tarbela units 9-12. The scheduling of the last units at Tarbela was also tested in programs designed to meet the Higher Load Forecast which the Bank Group also used for the Northern Grid area. The conclusions drawn from that study were that the advantages of having Tarbela 9-12 early were then slightly greater than they were with the main load forecast used for these studies; however, if Kunhar were also brought within the planning period as a means of meeting these higher Northern Grid loads then there were advantages to postponing the last units at Tarbela except at very high fuel prices (upwards of 70 cents per million Btu). The correct conclusion thus appears to be that, with loads and economic fuel values in the ranges that can now be foreseen for the early 1980's, early scheduling of the last units at Tarbela and postponement of Kunhar, at least into the late 1980's, would be the best course.

ANNEX 8

THE DEVELOPMENT OF MANGLA's POWER POTENTIAL

THE DEVELOPMENT OF MANGLA's POWER POTENTIAL

Table of Contents

THE DEVELOPMENT OF MANGLA's POWER POTENTIAL

The Mangla Reservoir on the Jhelum River should be fully completed in time to store water from the flood flows of summer 1967. It will be formed by the 11,000-foot long Mangla Dam and two long dikes, all of zoned earth embankment type. The reservoir will have an initial gross storage capacity of about 5.9 MAF and a live storage capacity of about 5.3 MAF at drawdown level of 1040 feet or 4.9 MAF at drawdown level 1075 feet. Presently it would not be possible to release 0.4 MAF of live storage through the main outlet works and the power plant because it is locked in the Jari Arm by the Mirpur Saddle, but a decision has been taken to cut a trench through the Saddle, which would enable about 0.3 MAF of this water to be diverted into the main reservoir and released through the power plant. Five diversion tunnels of 30 feet diameter were constructed through a ridge at the left abutment in order to divert water from the dam area during its construction. The four tunnels nearest the dam have been lined with steel penstocks of 26-foot inside diameter for their full lengths and they will be the initial means of releasing water for irrigation purposes and power generation. The fifth tunnel is plugged with a steel bulkhead at its intake end, but steel linings can be installed and the tunnel plug removed if and when it is required for irrigation purposes or for power generation. All the impounding structures of the Mangla Dam Project are designed for raising 40 feet to elevation 1274 feet; this would permit a 48-foot increase in full reservoir level (to elevation 1250 feet) - somewhat greater than the increase in the dam height because the larger surface of the higher reservoir would mean that floods could be handled with a smaller rise in reservoir elevation. Raising the maximum reservoir elevation to 1250 feet would permit an increase in live storage capacity in the neighborhood of 3.5 MAF.

The powerhouse at Mangla, located at the discharge end of the tunnels, will initially house three 100-mw generating units, two on tunnel no. 1 which were commissioned and operating satisfactorily by July 1967 and one on tunnel no. 2 which is scheduled for completion by June 1968. Each turbine will be linked with a companion bypass valve so connected as to maintain constant preset discharges regardless of changes in load on the turbine. Eight irrigation release valves are being installed immediately, so that an additional turbine can be added to tunnel no. 2 and two turbines can be added to tunnel no. 3 and also to tunnel no. 4. Discharge valves can be added to tunnel no. 5 and the powerhouse enlarged to accommodate an ultimate installation of ten generating units.

The Number of Units at Mangla

Installation of units 9 and 10 at Mangla does not look attractive if the reservoir is drawn down each spring to a minimum level of 1040 feet. They would add 90 mw of capability in the March-May period and they would be able to operate on base load during those months in a mean flow year. But they would add nothing to energy supplies at other times of year except a small amount in the summer when Tarbela and Mangla

together will anyway produce more energy than can be absorbed before the late 1980's. The capacity factor on the units would be only 15 percent even in a mean year. In a critical year flows plus releases planned under the irrigation consultant's latest release pattern would be sufficient, with a 1040-foot drawdown level, to generate no more than 20 million kwh from Mangla units 9 and 10 in the March-May period (see Appendix Table 2). However, the contribution that units 9 and 10 would make to meeting loads at the time of minimum drawdown level in the spring would be valuable. Whether it will be sufficiently valuable of offset the costs of the installation involved depends on a number of factors, particularly on whether or not tunnel number 5 will be required for irrigation purposes. If it is not required for irrigation, then the costs of lining the downstream end of the tunnel -- estimated at about $6-7 million -- would be a charge to power, and this would make the installation costly compared to gas turbines.

Units 7 and 8, on the other hand, would appear to be justifiable even with a minimum drawdown level of 1040 feet. They would add a firm capability in the spring of 90 mw and in the mean year they would produce about 800 million kwh of energy. A relatively large proportion of this additional output of energy would occur in the summer flood-months, but about 450 million kwh would be produced in the winter and the spring when it would be absorbable in most years. The extent of absorption in any particular year would depend on how rapidly the Tarbela units are brought in. A rough comparison of Mangla units 7 and 8 at a total cost, including transmission, of $18 million 1/ against a 100-mw Mari unit ($15.5 million, excluding transmission), on the assumption that an average of about 400 million kwh from the Mangla units could be absorbed each year, suggests that the Mangla units would be preferable at any price for thermal fuel above about 8 cents per million Btu. In fact absorption of energy from the Mangla units may be substantially less than 400 million kwh in the early years after completion of Tarbela. But 8 cents is also only one-half to one-third of the economic values for fuel in these years projected in Annex 5 on the basis of current estimates of gas reserves. Analysis of alternative power development programs on the simulation model suggested that there were savings to be had from bringing in Mangla units 7 and 8 in the early 1970's as proposed in the program outlined in Volume IV rather than in the early 1980's, as proposed by the power consultant.

The Drawdown Level at Mangla

Since Mangla should be fully completed later in 1967, the manner in which the reservoir should be operated is a top priority question. One of the most critical issues is the minimum level to which the reservoir should be drawn down each spring. By sacrificing about 0.4 MAF of live storage capacity at Mangla and raising the minimum drawdown level from 1040 feet to 1075 feet the head on the Mangla turbines

1/ See Annex 6, Appendix II, Table 3.

in the critical period from the end of March to the beginning of May can be raised 35 feet and the firm capability of eight units can be raised by about 140 mw. Operation with the higher drawdown level would increase usable energy in February-April from eight units by about 250 million kwh and reduce usable energy in November-January by about 130 million kwh. 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 300 million kwh from about 5,600 million kwh to about 5,900 million kwh. A portion of this increase would occur, as a result of the higher head maintained through the filling period, in July and August, when the system would anyway have a heavy surplus of energy at least through 1985.

Although the power consultant adopted a Mangla drawdown level of 1075 feet for purposes of preparing his program, it has been generally assumed that Mangla would in fact be drawn down to 1040 feet each year. In order to check the validity of this general assumption the Bank Group made studies with the aid of the agricultural linear programming model to assess the costs and benefits to agriculture of marginal changes in the live storage capacity of Mangla in the two decades 1965-75 and 1975-85 and studies with the aid of the power system simulation model to indicate the costs and benefits to power of such changes.

In order to assess the present worth of the gain to power from maintaining the 1075-foot drawdown level over the twenty-year planning period two alternative power programs were prepared, one based on the assumption that Mangla reservoir would be drawn down each year to 1040 feet and the other on the assumption that it would be drawn down to 1075 feet. All other items in the two power programs - the thermal plants, the EHV transmission system, the other hydro development, etc. - were held constant except insofar as they were directly affected by the higher capability available at Mangla. Table 1 shows the main differences between the two programs, as far as development in the Northern Grid area is concerned. Maintenance of the higher drawdown level permits postponement by a year or two of several generating capacity investments throughout the planning period and it also has the eventual result of reducing the need for additional capability by at least 100 mw. The table does not indicate the effect of the higher drawdown level on development in the South but some minor postponements of investment in generating capacity were made there also in the program based on the higher drawdown level. It is also noteworthy that despite the delay in the introduction of additions to generating capability the program with the higher drawdown level almost always shows a higher capability in the Northern Grid than the program with lower drawdown level - which means that less reliance has to be placed on supplies from Mari or that more hydro capability is available for 'export' to other areas. This is particularly important in 1971/72, for with a drawdown level of 1040 feet it will be impossible to meet loads in the North at that time (as projected here) without either more thermal capacity in the North or interconnection with Mari. Maintenance of the higher

Table 1

The Effect of Alternative Drawdown Levels at Mangla on the Phasing of a Heavily Hydro Power Program in the North
(Months in brackets are critical months in year in question)

	Program A (Mangla 1040', Tarbela 1300')		Program B (Mangla 1075', Tarbela 1300')	
1966	Existing	mw: 467 (Oct)	Existing	mw: 467 (Oct)
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	457 (Jan)	Lyallpur S1 (124) Mangla 1 & 2 (126)	457 (Jan)
1968	Lahore GT 2 (26) Lahore GT 3 (26)	743 (Mar)	Lahore GT 2 (26)	753 (Mar)
1969	Mangla 3 (45)	788 (Mar)	Mangla 3 (63)	816 (Mar)
1970	Mangla 4 (45) Mangla 5 & 6 (90)	923 (Mar)	Mangla 4 (63) Lahore GT 3 (26)	905 (Mar)
1971	Interconnection with South Retire'ts: Lyallpur, Montgomery (15)	908 (Mar)	Interconnection with South Retire'ts: Lyallpur, Montgomery (15) Mangla 5 & 6 (126)	1016 (Mar)
1972				
1973				
1974	Mangla 7 & 8 (90)	998 (Mar)	Mangla 7 & 8 (126)	1142 (Mar)
1975	Tarbela 1 & 2 (160)	1158 (Mar)	Tarbela 1 & 2 (160)	1302 (Mar)
1976	Critical changes to May Tarbela 3 & 4 (108)	1284 (May)	Critical changes to May Tarbela 3 & 4 (108)	1428 (May)
1977	Tarbela 5 & 6 (108)	1392 (May)	Tarbela 5 & 6 (108)	1536 (May)
1978	Warsak 5 & 6 (80) Tarbela 7 & 8 (108)	1580 (May)	Tarbela 7 & 8 (108)	1644 (May)
1979	Tarbela 9 & 10 (108)	1688 (May)	Warsak 5 & 6 (80)	1724 (May)
1980	Tarbela 11 & 12 (108) Kunhar 1 (203)	1999 (May)	Tarbela 9 & 10 (108)	1832 (May)
1981	Lyallpur 6 (200)	2199 (May)	Kunhar 1 (203)	2035 (May)
1982	Kunhar 2 (101)	2300 (May)	Tarbela 11 & 12 (108) Lyallpur 6 (200)	2343 (May)
1983	Kunhar 3 (102)	2402 (May)	Kunhar 2 (101)	2444 (May)
1984	Kunhar 4 (85) Lyallpur 7 (200)	2687 (May)	Kunhar 3 (102) Lyallpur P (100)	2646 (May)
1985		2687 (May)	Kunhar 4 (85)	2731 (May)
	(Systemwide thermal capability	3546		3446)

drawdown level at Mangla at that time would, on the other hand, permit the postponement of the interconnection by a year or two without involving further thermal development in the North.

The net benefits to power of maintaining the higher rather than the lower drawdown level over the twenty-year period is the difference between the present-worth costs of the two programs - or about $20 million when foreign exchange costs are calculated at the current exchange rate and about $30 million when foreign exchange is valued at twice the current rate. These cost differences are not very sensitive to changes in the assumption regarding the price of fuel; the figures cited are actually based on calculations at the current financial fuel prices in different parts of the Province, but they would only be about $3 million greater if all thermal fuel were priced at 70 ¢ per million Btu. This insensitivity to change in the assumption regarding the fuel price results partly from the fact that the chief effect of maintaining the higher drawdown level is to postpone the need for further additions to generating capacity; the effect on the total amount of energy available over the year from the hydroelectric station is small. It is also partly due to the fact that both the development programs compared using the simulation model rest on the implicit premise that fuel is costly - for if it were not so then it would not be worthwhile to undertake such intensive hydro development as the two programs both imply (i.e., rapid introduction of Tarbela units and Kunhar by 1980/81). Thus they both include heavy capital investment and relatively low fuel consumption.

The figures of $20 million and $30 million seem reasonable estimates of the benefits to power of maintaining the higher drawdown level under the two different assumptions regarding foreign exchange. Both programs include more hydro development than would be appropriate according to the results of the studies described in this volume. This in itself would imply that the difference in the present-worth costs of the two programs tends to exaggerate the real benefits of maintaining the higher drawdown level; for the saving to be had from postponement of investment in costly hydroelectric capability is greater than the saving that can be achieved by postponing the installation of less costly thermal capability. Offsetting this is the fact that the program with the 1075 feet drawdown level is in general rather more amply proportioned than the program with the lower drawdown level; reserve capabilities are generally a little larger, for instance, and interconnection is introduced a year or two before it might be essential, as pointed out in discussion of the two programs. In other words the program with the higher drawdown level is probably subject to more refinement and compression of investment than the one with the lower drawdown level.

As for the agricultural benefits of drawing down fully rather than to 1075 feet, the Bank Group's linear programming exercise tends to confirm the results of other studies in that it indicates a high marginal value for additional supplies of irrigation water in the decade 1965-75. The initial assumption made in the linear programming analysis regarding availability of irrigation water from Mangla was that

the reservoir would be drawn down each year to 1040 feet. An indication of the sacrifice involved in maintaining the higher drawdown level was obtained by tightening the constraint on surface water supplies (assuming that only 4.9 MAF would be available each year rather than 5.3 MAF) and checking the effect of this on the shadow price for surface water yielded by the linear program solution. The present worth of the agricultural benefits lost by drawing down to 1075 feet instead of 1040 feet in the years 1967-75 is estimated, on this basis, at $20 million. After Tarbela is completed in 1975 the marginal value of irrigation water will be less, partly because of the sizable addition to rabi water supplies made by Tarbela, and partly because of the substantial opportunities that will then exist for overpumping. The sacrifice involved by cutting back 0.4 MAF from the assumed availability of 5.0 MAF 1/ from Mangla in each year of the 1975-85 decade is estimated to have a present worth of about $1.5-8.0 million, the lower figure applying if Sehwan-Manchar is completed about 1980. Thus for the whole period 1965-85 the present worth of the sacrifice to agriculture from operating Mangla to 1075 feet instead of 1040 is estimated at about $22-28 million.

The figures from the linear program are comparable with the calculations in the power simulation model based on the current foreign exchange rate. Therefore the evidence, particularly for the first ten years of the planning period indicates fairly clearly that greater benefit will be derived from operating Mangla to the lower rather than the higher drawdown level.

The Planning of Drawdown Levels

Consideration of drawdown levels in terms of periods of ten or twenty years is useful for indicating the general order of priority between agriculture and power for use of water stored in the reservoirs, but it does neglect two critical aspects of the problem of reservoir operation, as pointed out in Annex 6 -- the fact that the level to which a reservoir is drawn down can always be changed from year to year, and the fact of hydrological uncertainty. In practice it will probably be necessary to plan a few years ahead for a certain drawdown level at Mangla 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 large variations over the years in the benefits of maintaining the higher or the lower drawdown level. In some years the additions to power system capability, for instance, 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 Volume IV. Examples are 1971,

1/ Slightly less than in 1967-75 period because of siltation in the interim.

when maintenance of 1075 feet at Mangla might make possible one-year postponement of the transmission tie between the North and Mari, as pointed out in discussion of the programs with alternative drawdown level. Another is 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. Besides the size of the savings to be obtained by maintaining the higher drawdown level, some consideration has also to be given to the unpredictability of hydrology. The years when maintenance of the higher drawdown level would seem particularly appropriate from the power point of view may turn out to be years when irrigation water is especially short. They might equally turn out to be years when water is so plentiful that the benefits to power clearly outweigh any marginal increment in benefits that might result from providing more irrigation water. Development of a sound basis for forecasting flows - probably on the basis of historical flow statistics or possibly by meteorological analysis - will help in short-term decision-making regarding drawdown levels by indicating, for instance, the extent of the risk that a year when maintenance of a higher drawdown level would yield substantial savings to power may also be a bad hydrological year.

Consideration of hydrological uncertainty may prompt planning for maintenance of a higher drawdown level than would otherwise be the case. For it may be possible for the power system to cope with hydrological uncertainty within the frame of its normal provision against other types of uncertainty - the possibility of thermal generator and transmission line outages, etc. Assessment of the risk of shortage due to these several different causes must be made in conjunction with consideration of the losses to the economy and to WAPDA that might result from failure to meet peak loads in a bad hydrological year. One of the chief results of the great fluctuations that will occur over the year in the capability at Mangla is that, if sufficient total capability exists on the system to meet peak loads in the critical period, then reserves will be extremely ample in the rest of the year. In other words, in strong contrast to a purely thermal system, or one with constant-head hydro plants, the effects of any unforeseen shortages in capability that occur will be serious only at the time of minimum drawdown level and, even then, only for relatively short periods. To illustrate this point the year 1975 has been selected as a year for which it might be appropriate to plan a 1075-foot drawdown level, as suggested above. If 1975 proved to be a year of low rabi flows it might be necessary to diverge from the plan and to release all the water stored at Mangla. The following Table 2 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.

Table 2, which does not take account of reserve generating capabilities, 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

Table 2

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
Complementary Thermal	1262	1334	1414	1235	1235	1235	1302	1182	1102
Hydroelectric Capability (with 1040' at Mangla)									
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

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).

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 may be a small price to pay for the saving obtainable from postponing a substantial investment in generating capability (and possibly transmission) for a year or two. Moreover this calculation of the load-shedding supposedly involved rests on the assumption that the shortage of capability cannot be taken up within the scope of reserves on the system at the time. The proposed power program includes about 200 mw of reserve generating capability in 1975 so that if all other equipment can be kept in working order for these very short periods of capability shortage then no load-shedding would be necessary. These figures appear to argue quite strongly in favor of the kind of planning that would allow for 1075 feet at Mangla in 1975, and probably in other years - but maintaining 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.

Raising Mangla for Power

It was pointed out at the beginning of this annex that provision has been made in the construction of Mangla for its subsequent raising. Raised Mangla as an early project to supply additional irrigation water, with Tarbela postponed to 1985, was discussed in Annex 7 and found unattractive. However the surface water storage program modelled around Tarbela's completion in 1975 did include the raising of Mangla for irrigation purposes in 1985. The question arises whether it might be worthwhile to raise Mangla a few years earlier than this to provide a temporary supplement to power supplies. If Mangla Dam were raised to 1274 feet and the minimum reservoir level increased to 1175 feet then High Mangla would have about the same live storage as Low Mangla in the early 1980's with a drawdown level of 1040 feet (i.e. about 4.9 MAF) - and, at the same time, there would be a much higher head on the turbines throughout the year. The effect would be to raise the capability of the hydroelectric plant considerably in the winter and the spring.

Table 3, which is based on Appendix Table 1 to this Annex shows the increase in mean-year capability and energy output that would result from raising Mangla and drawing down to 1175 feet each year. The base is taken as Low Mangla, with eight units, drawn down to 1040 feet.

The first two columns indicate the increase in capability and energy-output that would result from simply raising Mangla and drawing down to 1175 feet. The second two indicate the results of raising the dam, drawing down to 1175 feet and adding units 9 and 10 at the same time. The last two columns show the monthly patterns of capability and energy output from Kunhar for comparative purposes.

TABLE 3

Increase in Power-Output Obtainable by Raising Mangla, Compared with Kunhar Power-Output
(Mean Year)

	Increase[a] due to Raising Mangla & drawing down to 1175 feet		Increase[a] due to Raising Mangla, drawing down to 1175 feet and adding units 9 and 10		Kunhar: Power Capabilities and Energy-Output	
	mw	Mln. kwh	mw	Mln. kwh	mw	Mln. kwh
Jan.	278	79	570	79	567	233
Feb.	310	131	590	131	549	215
Mar.	450	308	710	355	524	239
Apr.	592	422	840	514	503	215
May	488	334	744	375	491	214
June	314	138	600	138	573	214
July	204	139	600	153	594	286
Aug.	114	91	410	207	594	394
Sept.	84	91	380	91	594	276
Oct.	114	114	310	114	594	202
Nov.	184	71	480	71	591	196
Dec.	248	57	544	57	586	220
Total Energy		1,975		2,285		2,904
Energy (June-Sept.)		-459		-589		-1,170
Energy (Oct.-May)		1,516		1,686		1,734
Cost of Project: ($ mln)		217		235		204

a/ Base is Low Mangla drawn down to 1040 feet (see Appendix Table 1)

Maintenance of a minimum reservoir level at Mangla of 1175 feet as opposed to 1040 feet, would result in an increase of nearly 600 mw in the firm capability of the power plant, with eight 100 mw un units installed. Installation of a further two units would increase this firm capability by an additional 240 mw. Raising Mangla and drawing down to 1175 feet would also result in a very substantial addition to energy output in the critical period of the year. In both these senses Raising Mangla would be more attractive than Kunhar. However Kunhar would produce more energy over the year as a whole. Even when energy output in June-September is subtracted out Kunhar still adds more energy than the Raising of Mangla (see bottom of Table 3); this is especially the case in the winter months, when the system will be short of energy by the early 1980's. Kunhar may also be less expensive than Raised Mangla though it should be pointed out, that the Raised Mangla cost estimate is very recent[1/] (1966) whereas the Kunhar cost estimate dates from 1961.[2/]

Some rough calculations on the basis of these figures suggest that Raising Mangla for power purposes a few years before it is required to meet irrigation needs is not attractive, given the fuel price framework developed in Annex 5. A rough comparison between Raising Mangla for power purposes in 1983, five years before it would be required for irrigation purposes according to present projections, and, on the other hand, installation of the Mari/Sui units proposed in the power program in Volume IV for the early 1980's suggests that the fuel price at that time would have to reach at least 65 cents per million Btu to make the early raising of Mangla preferable to the proposed thermal units. This calculation, which was made on the basis of the current foreign exchange rate, assumed that all the energy added to the output of the Mangla plant during the winter and the spring (i.e. 1,500 million kwh) could be absorbed in each of the years 1983 through 1987; this assumption errs on the side of favoring the Raised Mangla project. Even a fuel price of 65 cents per million Btu is substantially above the economic fuel prices projected in Annex 5 for the middle 1980's on the assumption that Tarbela is completed in 1975. It is also above the fuel price at which Kunhar appears to become attractive in the 1980's. Thus it would appear that the growth of power loads and/or the fuel price situation of the 1980's would have to be substantially different from those foreseen here to make the Raising of Mangla for power purposes an attractive project.

1/ It should be noted that this most recent cost-estimate is about 30 percent above the previous one.

2/ The Kunhar cost estimate is based on the Charles T. Main supplemental report with an addition for high tension transmission (see Annex 6, Appendix II, Table 5.

APPENDIX TABLE I

LOW MANGLA AND HIGH MANGLA - LIVE STORAGE 4.9 MAF

Mean Year Flows

	Low Mangla - 1040'						High Mangla - 1175'					
	8 units			10 units			8 units			10 units		
	mw	mln kwh	O.F.	mw	mln kwh	O.F.	mw	mln kwh	O.F.	mw	mln kwh	O.F.
Oct 1	1104	238	89.9	1380	238	71.9	1184	278	97.8	1480	278	78.2
11	1072	212	82.7	1340	212	66.2	1184	250	88.0	1480	250	70.4
21	1048	196	78.3	1310	196	62.7	1184	232	81.6	1480	232	65.3
Nov 1	1024	139	56.4	1280	139	45.1	1184	163	57.5	1480	163	46.0
11	1000	130	53.9	1250	130	43.1	1184	153	53.8	1480	153	43.0
21	976	122	52.1	1220	122	41.7	1184	146	51.4	1480	146	41.2
Dec 1	952	95	41.3	1190	95	33.0	1184	114	40.0	1480	114	32.0
11	936	97	43.0	1170	97	34.4	1184	116	40.8	1480	116	32.7
21	928	95	42.6	1160	95	34.1	1184	114	40.0	1480	114	32.1
Jan 1	912	95	43.9	1140	95	35.1	1176	115	40.8	1470	115	32.7
11	888	95	44.4	1110	95	35.5	1168	131	47.0	1460	131	37.6
21	880	103	49.3	1100	103	39.5	1160	126	45.4	1450	126	36.3
Feb 1	864	180	86.5	1080	180	69.2	1144	218	79.6	1430	218	63.7
11	808	183	94.5	1010	183	75.6	1128	227	84.1	1410	227	67.3
21	752	182	100.0	940	183	80.3	1096	231	88.2	1370	231	70.6
Mar 1	672	161	100.0	840	177	88.2	1064	239	93.3	1330	239	74.7
11	584	142	100.0	730	177	100.0	1040	250	100.0	1300	257	82.0
21	512	122	100.0	640	153	100.0	1016	244	100.0	1270	284	93.2
Apr 1	400	96	100.0	500	120	100.0	992	234	98.5	1240	234	78.8
11	400	96	100.0	500	120	100.0	992	238	100.0	1240	270	90.5
21	400	96	100.0	500	120	100.0	992	238	100.0	1240	298	100.0
May 1	400	96	100.0	500	120	100.0	992	220	92.5	1240	220	74.0
11	536	128	100.0	670	161	100.0	1024	246	100.0	1280	260	84.4
21	664	160	100.0	830	199	100.0	1056	252	100.0	1320	279	88.5
Jun 1	728	175	100.0	910	176	80.2	1088	224	86.1	1360	224	68.9
11	832	192	97.5	1040	192	90.0	1136	239	87.7	1420	239	70.2
21	896	213	99.0	1120	213	79.2	1168	255	91.2	1460	255	73.0
Jul 1	944	226	100.0	1180	260	88.4	1184	284	100.0	1480	298	84.0
11	992	227	95.4	1240	227	76.3	1184	268	94.4	1480	268	75.5
21	1024	226	91.9	1280	226	73.5	1184	266	93.8	1480	266	75.0
Aug 1	1065	256	100.0	1330	319	100.0	1184	284	100.0	1480	355	100.0
11	1080	259	100.0	1350	279	86.2	1184	284	100.0	1480	329	92.7
21	1088	226	86.2	1360	226	69.0	1184	264	92.8	1480	264	74.2
Sep 1	1104	224	84.6	1380	224	67.7	1184	261	92.0	1480	261	73.6
11	1104	181	68.2	1380	181	54.6	1184	211	74.2	1480	211	59.3
21	1104	146	55.1	1380	146	44.0	1184	170	59.9	1480	170	47.9
		5810			6179			7785			8095	

APPENDIX TABLE II

LOW MANGLA AND HIGH MANGLA - LIVE STORAGE 4.9 MAF

Critical Year Flows

	Low Mangla - 1040'						High Mangla - 1175'					
	8 units			10 units			8 units			10 units		
	mw	mln kwh	O.F.	mw	mln kwh	O.F.	mw	mln kwh	O.F.	mw	mln kwh	O.F.
Oct 1	1104	232	88.0	1380	232	70.4	1184	272	95.7	1480	272	76.5
11	1072	213	83.3	1340	213	66.6	1184	252	88.7	1480	252	70.9
21	1048	199	80.3	1310	199	64.2	1184	238	83.7	1480	238	67.0
Nov 1	1024	154	62.2	1280	154	49.8	1184	180	63.5	1480	180	50.8
11	1000	139	58.0	1250	139	46.4	1184	165	58.0	1480	165	46.3
21	976	126	54.1	1220	126	43.3	1184	152	53.5	1480	152	42.8
Dec 1	952	101	43.6	1190	101	34.9	1184	120	42.2	1480	120	33.8
11	936	93	41.3	1170	93	33.0	1184	111	39.2	1480	111	31.4
21	928	91	40.5	1160	91	32.4	1184	108	38.1	1480	108	30.4
Jan 1	912	83	38.4	1140	83	30.7	1176	101	35.7	1470	101	28.6
11	888	82	38.1	1110	82	30.5	1168	98	35.1	1460	98	28.1
21	880	80	38.5	1100	80	30.8	1160	99	35.9	1450	99	28.4
Feb 1	864	147	70.5	1080	147	56.4	1144	179	65.5	1430	179	51.9
11	808	136	70.7	1010	136	56.6	1128	173	64.2	1410	173	50.4
21	752	133	72.5	940	133	58.0	1096	169	64.4	1370	169	51.0
Mar 1	672	114	71.5	840	114	57.2	1064	156	61.0	1330	156	48.4
11	584	133	92.5	730	133	74.0	1040	188	75.4	1300	188	59.6
21	512	120	100.0	640	131	87.5	1016	209	85.6	1270	209	68.5
Apr 1	400	96	100.0	500	96	79.7	992	171	71.9	1240	171	57.5
11	400	96	100.0	500	106	88.0	992	189	79.3	1240	189	63.5
21	400	86	89.2	500	86	71.4	992	152	63.7	1240	152	51.5
May 1	400	64	66.6	500	64	53.3	992	113	47.5	1240	113	38.4
11	536	85	66.2	670	85	53.0	1024	127	51.5	1280	127	41.6
21	664	103	64.4	830	103	51.5	1056	135	53.5	1320	135	43.6
Jun 1	728	85	48.1	910	85	38.4	1088	105	40.4	1360	105	33.0
11	832	125	62.7	1040	125	50.2	1136	154	56.5	1420	154	45.2
21	896	89	41.1	1120	89	32.9	1168	109	39.0	1460	109	30.3
Jul 1	944	136	60.9	1180	136	48.7	1184	173	60.9	1480	173	46.3
11	992	153	63.8	1240	153	51.0	1184	188	66.3	1480	188	50.5
21	1024	105	42.4	1280	105	33.9	1184	127	44.7	1480	127	34.6
Aug 1	1065	256	100.0	1330	320	100.0	1184	284	100.0	1480	355	100.0
11	1080	256	100.0	1350	320	100.0	1184	284	100.0	1480	355	100.0
21	1088	264	100.0	1360	330	100.0	1184	284	100.0	1480	355	100.0
Sep 1	1104	261	98.7	1380	261	78.9	1184	284	100.0	1480	305	85.9
11	1104	186	70.4	1380	186	56.3	1184	218	76.6	1480	218	61.3
21	1104	152	57.5	1380	152	46.0	1184	178	62.6	1480	178	50.1
		4974			5189			6245			6479	

ANNEX 9

ENERGY TRANSMISSION:
EHV INTERCONNECTION AND GAS PIPELINES

ENERGY TRANSMISSION: EHV INTERCONNECTION AND GAS PIPELINES

Table of Contents

Table of Contents (cont'd)

ENERGY TRANSMISSION: EHV INTERCONNECTION AND GAS PIPELINES

Following the question of Tarbela, the second most important decision affecting the future of the electric power system in West Pakistan at the present time concerns bulk transmission. A considerable amount of attention has been given to the bulk transmission question both by Stone & Webster and, more recently, by WAPDA's consultants, Harza Engineering Company. Another closely related matter which is also important in long-term planning is the amount of gas pipeline capacity that will be required to meet the needs of the electric utilities. WAPDA & KESC have prepared several estimates of their future gas requirements to assist the planning of the gas transmission companies, Sui Northern Gas Pipelines Limited for the area north of Sui and Sui Gas Transmission Company Limited for the area to the south. This annex is concerned with trying to identify the best overall pattern for the development of electrical transmission and gas transmission for the generation of electric power.

The Existing Situation

At present, West Pakistan has two large electric load concentrations -- the Northern Grid (1965 gross peak of about 470 mw including 40 mw allowance for load shed) and Karachi (1965 gross peak of about 130 mw). There are two other relatively minor load centers -- Hyderabad or Lower Sind (1965 gross peak of about 30 mw) and Sukkur or Upper Sind (1965 gross peak of about 5 mw) -- which are located between the Northern Grid area and Karachi. While the Northern Grid extends over 500 miles north and south, about 60 percent of the load is contained in a belt 100 miles wide extending from Lahore to 25 miles west of Lyallpur. The electrical load center for the Northern Grid is located just northeast of Lyallpur. The Karachi load is concentrated within a 15-mile radius. These two load centers are separated by 575 air miles.

The four load concentrations discussed are not at present electrically connected, but they are all served by gas pipelines emanating from the Sui field in the Upper Sind area. The Northern Grid area is tied together electrically by an eight-year old 132-kv line connecting Warsak, Malakand, and Dargai hydro plants in the northwest with load centers along the Rawalpindi-Lahore and Sargodha-Lyallpur load axes. WAPDA's main thermal plant at Multan, to the south of the main grid is linked to it by a 220-kv line. The Multan plant, in turn, is linked to the Sui gas field by a 16-inch pipeline completed in 1958. In 1965 about 60 percent of the electric energy supplied to the Northern Grid area came from the hydro-electric plants and about 40 percent from the Multan thermal station. During 1965 the Sui gas pipeline was extended from Multan to Lyallpur, and WAPDA's new thermal station at Lyallpur will burn Sui gas. The other electrical systems in West Pakistan are entirely dependent on thermal generation; they are all situated along the 16-inch Sui gas pipeline which extends from the Sui field to Karachi and they draw on the pipeline for almost all of their fuel requirements. Electrical transmission in the

Upper Sind area is by means of 66-kv lines which radiate out from the new thermal station at Sukkur. The lines in the Lower Sind area operate at 34.5 kv and are centered on the new thermal plant in Hyderabad. The City of Karachi is encircled by a 66-kv loop, to which the new Korangi station is linked by two single-circuit 132-kv lines. A double-circuit steel tower line extending eastwards eighteen miles towards Dhabeji is nearing completion. This line will operate at 66 kv but is designed for future 132-kv use. A decision by KESC & WAPDA to extend it the further 50-60 miles to Hyderabad/Kotri is understood to be imminent, and, as pointed out in Chapter II of Volume IV, the existence of this line has been assumed in most of these studies.

Stone & Webster Proposals

In their report Stone & Webster recommended that these four load centers should be interconnected in the early 1970's by a 380-kv transmission system which would also be extended to Tarbela in 1974. The first link which they recommended was one between Karachi and Mari in 1971, which would enable Karachi to take advantage of the cheap gas believed to be available at Mari and also eliminate the need for the addition of further thermal capacity in Karachi between completion of the 125-mw Korangi C unit in 1969 and the time that the Pakistan Atomic Energy Commission's Karachi nuclear plant assumes reliable operating status in 1971 and 1972. The second 380-kv line which Stone & Webster foresaw was one between Mari and Lyallpur, coming into operation in 1973. Three main advantages were attributed to this line: it would make it possible to carry large quantities of hydro energy down to Karachi and thus save on fuel there, it would save on investment in generating capacity by consolidating the reserves of all main load centers, and it would enable the North to draw on generators fired by cheap Mari gas rather than generators in the Northern Grid area fired by Sui gas for its power supplies at times of low hydro capability. Most of these factors would become important at a later date, but nevertheless Stone & Webster thought it would be desirable to link Mari and Lyallpur as early as 1973 so as to avoid the need for more capacity investment in the North prior to the completion of Tarbela. As early as 1973, it would also be possible to take some excess hydro energy (from Mangla units 1-6) south in months when Mari power was not needed for the north. To enable the Mari-Karachi line to carry the excess hydro power from the North and, more especially, to provide sufficient security of supply -- since Karachi would be drawing firm power from Mari by 1973/74 -- Stone & Webster recommended addition of a second single-circuit 380-kv line between Mari and Karachi in 1973. They also scheduled the first Tarbela-Lyallpur line in 1974. On their program the lines between Tarbela and Lyallpur and between Lyallpur and Mari were duplicated by the addition of second single-circuit lines in 1977 when Tarbela units 5 & 6 came in; and a further single-circuit line between these points was added in 1982/83 along with completion of the last four units at Tarbela.

Stone & Webster compared 380 kv and 500 kv as voltages for the transmission system and concluded that 380 kv was slightly cheaper and also had certain operating advantages. Their economic analysis took the

form of cost-streaming the investment and operating expenditures involved in the development of the two systems between 1965 and 1985, and allowing credits to the 500-kv system in the later years for its ability to carry greater amounts of excess hydro energy and cheap Mari energy into Karachi than could be carried by the 380-kv system. Discounting the net cost streams of the alternative systems at 8 percent, they found that the 380-kv system was about 11 percent cheaper in terms of present worth. On the economic side, Stone & Webster also felt the fact that expenditures for the 380-kv system would arise in smaller blocks than for the 500-kv system meant that there was more chance of carrying through with the 380-kv system. On the technical side Stone & Webster also attributed a number of advantages to 380-kv. It was pointed out that by 1973/74, Karachi would be relying, on the Stone & Webster generating program, for firm capacity from Mari -- and that this was an important part of the reason for adding a second 380-kv line between Mari and Karachi as early as 1973. A single 500-kv line could carry the load but it would not provide the same security, and two 500-kv lines at such an early stage would be very expensive. Introduction of either 380-kv or 500-kv transmission will initially cause difficult operating problems and require large quantities of reactive power generation; both should be less with 380 kv than with 500 kv. 380-kv transmission will also fit more easily into the existing transmission system; the 132-kv lines can be expanded to handle blocks of power delivered from the 380-kv line, whereas they might have to be at least partially replaced with 220-kv lines if 500-kv were made the main transmission voltage. Finally, Stone & Webster pointed out that the capacity of the 380-kv system could be increased as and when required by quite modest expenditures on series capacitors and intermediate switching stations on the longer sections of line; they estimate, for example, that the capacity of the Mari-Lyallpur line could be doubled by these means. Their program includes installation of one intermediate switching station at Moro to increase the capability and stability of the Mari-Karachi line.

Harza Proposals

Harza conducted detailed technical studies to identify stable transmission systems for West Pakistan and made economic studies to select among them. 1/ Their schemes envisage an initial EHV line from Mari to Karachi in 1972 and a second EHV line from Mari to Lyallpur in 1973. They felt that a proper comparison between voltages could only be made over a longer period than 1965-85, and so they extended their analysis to 1990. They also took into account the heavier transmission losses that their technical studies showed would occur with a 380-kv system. Their economic studies include a large debit to 380-kv on account of transmission losses. Their analysis led to the conclusion that the relative merits of the alternative voltages in present worth terms depended on the discount rate

1/ Harza Engineering Company, "West Pakistan Electric Power System Load Flow and Stability Studies" (August 1966), and "Economic Studies of EHV transmission for West Pakistan" (September 1966).

used. At rates below 6 percent, the 500-kv system was cheaper than the 380-kv system in present-worth terms. Between 6 percent and 8 percent the present worth costs of the two systems were quite similar. At interest rates above 8 percent there was an increasing advantage to 380-kv. Their final judgment was that the balance of advantage lay with the higher voltage system since their view was that, as manufacturing and operating experience with 500 kv is gained, its costs would come down more rapidly than those for the longer-established 380-kv voltage, and that loads might well grow more rapidly than they had projected, so that the lower-voltage system would prove inadequate more quickly than presently anticipated.

Bank Group's Studies

The Stone & Webster and Harza studies were based on the important assumption that sufficient gas would be available at Mari to support 1500-2000 mw of generating capability there. It now seems quite possible that this is not the case. This makes a sufficiently important change in basic assumptions to raise again the question of whether EHV interconnection should be introduced in West Pakistan in the 1970's. Stone & Webster have suggested that if indeed Mari cannot support more than 400 mw of capability (which is the current view, given the new estimates of gas reserves 1/) then it may be preferable to delay full development there until after 1975 and to keep the Karachi-Hyderabad and Northern Grid areas self-sufficient at least into the later 1970's. With the new uncertainty regarding gas reserves, the Bank Group's studies have focused mainly on the question of whether EHV interconnection should still be introduced even if there is a more limited reserve of gas at Mari, on when it should be introduced and upon the relationship between the construction of new transmission lines and the addition of generating units at Mangla and Tarbela. Detailed attention has not been given to the question of transmission voltage, though the Bank Group does find Stone & Webster's arguments persuasive and has in fact carried out most of its studies with 380-kv transmission systems.

Figure 2 of Annex 7 which compared the present-worth costs at 8 percent of power development programs including Tarbela with those of the cheapest alternative under different assumptions with regard to the price of thermal fuel suggested that the benefits of interconnection were quite sensitive to changes in assumptions regarding fuel prices and foreign exchange rate. The calculations presented in that figure were based on uniform fuel prices throughout West Pakistan. The figure implied that, with that assumption, a program including interconnection was preferable to one excluding interconnection when the fuel price was greater than 30 cents per million Btu if foreign exchange was valued at the current exchange rate, but when foreign exchange was attributed its scarcity value, then interconnection only became worthwhile if the fuel price was assumed to be greater than 40 cents per million Btu.

1/ See Annex 4.

TABLE 1

Tarbela with Interconnection and 400 MW at Mari

(Drawdown Levels: Tarbela 1332', Mangla 1040')

	NORTHERN GRID				PEAK LOADS			MARI		HYDERABAD - KARACHI		Cumulative
	System Additions	Thermal Capab. (MW)	Hydro Capab. (MW)	Total Capab. (MW)	North	Mari	South	System Additions	Capa-bility (MW)	System Additions	Capa-bility (MW)	Total Sys. Capability
1966	Existing	302	165	467	513 (Oct)	11 (Oct)	194 (Dec)	Existing	50	Existing	280	
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	302	155	457	513 (Jan)	17 (Oct)	225 (Oct)		50	Hyderabad S2 (15) Kotri OFT (12)	307	
1968	Lahore GT 2 (26) Lahore GT 3 (26)	478	265	743	598 (Mar)	22 (Oct)	271 (Oct)		50	Kotri GT (40)	347	
1969	Mangla 3 (45)	478	310	788	690 (Mar)	29 (Oct)	321 (Oct)		50	Korangi 3 (125)	472	
1970	Mangla 4 (45) Mangla 5 & 6 (90)	478	445	923	813 (Mar)	45 (Oct)	382 (Oct)	Mari S1 (100)	150	Hyderabad GT 2 (26)	498	
1971	Interconnect w. Mari (380 Kv) Retire: LYA S (10) MONT S (5)	463	445	908		1334 (Mar)		Interconnect w. N.& S. Mari S2 (100)	250	Interconnect w. Mari (380 kv) Karachi N1 (25)	523	1681
1972		463	445	908		1501 (Mar)			250	Karachi N1 (100)	623	1781
1973		463	445	998		1688 (Mar)		Mari P (200)	450	Retire: KAR A (15)	608	1966
1974	Mangla 7 & 8 (90)	463	535	998		1877 (Mar)			450		608	2056
1975	Tarbela 1 & 2 (180)	463	715	1178		2093 (Mar)			450	Korangi 4 (125)	733	2361
1976	Tarbela 3 & 4 (180)	463	895	1358		2268 (Mar)		Second interconnection w.S.	450	Second interconnection with Mari	733	2541
1977		463	895	1358		2475 (Mar)			450	Korangi 5 (200)	933	2741
1978	Critical Changes to May Warsak (80)	463	977	1440		2712 (May)			450	Korangi 6 (200)	1133	3023
1979	Tarbela 5 & 6 (146) 2nd interconnection w. Mari	463	1123	1586		2966 (May)		Second interconnection with N.&S.	450	Korangi 7 (300)	1433	3469
1980	Tarbela 7 & 8 (146)	463	1269	1732		3250 (May)			450		1433	3615
1981	Tarbela 9 & 10 (146) Lyallpur 5 (150) 3rd interconnection w. Mari	613	1415	2028		3524 (May)			450		1433	3911
1982		613	1415	2028		3818 (May)			450	Karachi N3 (400)	1833	4311
1983	Tarbela & 12 (146) Lyallpur 6 (200)	813	1561	2374		4165 (May)			450		1833	4681
1984		813	1561	2374		4494 (May)			450	Karachi N4 (400)	2233	5057
1985	Lyallpur 8 (300)	1113	1561	2674		4864 (May)			450		2233	5357

To obtain a better grasp of the pros and cons of electrical interconnection between the power markets additional studies were run on the basis of the two Tarbela programs mentioned above (Annex 7, Tables 4 and 5) and a third program including Tarbela and interconnection, but based on the assumption that only 400 mw could be developed at Mari -- see Table 1 of this Annex. It will be noticed that all three programs are very similar to one another, in that they all include two 400-mw nuclear units in Karachi in the early 1980's, as well as all the hydro units at Warsak, Tarbela and Mangla discussed in the preceding annexes while all other additions to generating capacity are assumed to be gas-fired thermal units. The scheduling of these various thermal and hydro units varies among the programs according to whether or not intermarket transmission is available and the amount of transmission capacity available. The 'without interconnection' program includes 300 mw of capability at Mari, the new program introduced in this Annex provides for 400 mw at Mari, and the old 'with interconnection' program included 1100 mw at Mari. The two programs with limited development at Mari make up for the absence of capacity there with additional thermal units in the South (Hyderabad-Karachi) and the Northern Grid area fired by Sui gas. Both 'with interconnection' programs assume that the first step in interconnection will be construction of a 380-kv line all the way from Karachi to Lyallpur for operation in 1971.

Analysis with Financial Fuel Prices

Comparison of the present-worth costs of these programs on the basis of financial prices for fuel suggests that the program including interconnection and with 400 mw at Mari has a slight advantage over the 'without interconnection' program when foreign exchange costs are counted at the current rate -- but almost none when foreign exchange is attributed its scarcity value. The program with 1,100 mw at Mari looks better but this is almost entirely due to greater use of Mari fuel, which, it will be recalled, is attributed a financial price of 14 cents per million Btu against (financial) prices of 36 cents for Sui fuel delivered to Karachi and 50 cents for Sui fuel delivered to the North.

Table 2

Comparison of Present-Worth Costs of Programs With & Without Interconnection & With Different Amounts of Development at Mari (Financial Fuel Prices)

(US$ millions discounted at 8 percent)

Program	Present-Worth of Total System Costs, 1966-2000	
	Current Exch. Rate ($1=PRs 4.76)	Shadow Exch. Rate ($1=PRs 9.52)
Without interconnection	577	872
With interconnection & 400 mw at Mari	564	870
With interconnection & 1,100 mw at Mari	554	858

These figures appear to confirm the doubts raised by Stone & Webster about

the value of interconnection in the absence of substantial reserves of cheap gas at Mari available for commitment to power. At the current foreign exchange rate and at financial fuel prices a program including interconnection looks marginally superior to one without it; but when foreign exchange is priced at a rate closer to its scarcity value the programs seem to have little advantage over one another -- and then it is probably better to pick the one implying the smaller capital commitment, i.e. the program excluding interconnection.

Economic Fuel Prices

With these doubts thrown upon the validity of interconnection it appeared worthwhile to examine how the situation would look if the calculations were made in terms of the economic prices for fuel developed in Annex 5. Since all the programs considered here included Tarbela in 1975 the economic fuel prices calculated on that assumption were used. Because all programs include Tarbela in 1975, they also involve extremely little thermal fuel consumption in the North, especially after 1975. Not only would the total amount of thermal fuel consumed be small (of the order of 2-4 trillion Btu's per annum) but it would also be heavily concentrated in the two-four months in the spring when the energy available from the hydro plants is relatively small. Direct supply of much of this fuel by gas pipeline would involve an intolerably low load factor on the pipeline. Either gas storage facilities would have to be built or WAPDA would have to use imported fuel oil. This question is discussed at greater length below, but here it is sufficient to say for these reasons all thermal fuel requirements of the Northern Grid area in 1975-85 were assumed to be met from imported fuel oil (price delivered Lyallpur at the current scarcity rate of foreign exchange about 83 cents per million Btu -- see Annex 5). Thermal fuel supplies for the other conventional plants, whether located at Mari or in the South, were priced for this calculation at the appropriate prices for each year given in Annex 5 Table 3. The calculations were made for both assumptions regarding the extent of natural gas reserves.

Gas Pipeline Capacity Requirements of Alternative Programs

Use of the economic well-head prices for natural gas requires that a separate calculation be made, where appropriate, for the cost of transmitting gas from the Sui field to the location where it is to be used for power generation. This cost arises largely in the form of investments in gas pipeline capacity. The extent of capacity required depends, under present circumstances in West Pakistan, on peak-day gas requirements. Determination of likely peak requirements of natural gas for power generation is not simple because the advent of substantial hydro or nuclear capacity to fill in base load will materially alter the relationship between average day gas requirements and peak-day gas requirements. Peak-month gas requirements of the different programs under consideration are fairly readily derivable from the computer print-outs. Peak-day requirements within these months have been derived

by means of a formula which takes account of the ratio between peak-day electrical energy requirements in a month and average daily energy requirements, on the one hand, and the extent to which this energy is supplied from hydro or nuclear or, primarily for the South, Mari sources, on the other. 1/ This formula allows for the tendency that will exist for gas-fired plants to be more in peaking service so that, the base daily gas requirements being smaller, daily fluctuations in gas requirements become more significant. Figure 1 shows the peak-day requirements of gas for power generation in the South implied by the program 'without interconnection' and 'with interconnection and 1,100 mw at Mari'. The figure also shows the average-day requirements of the two programs. The numbers underlying the figure are shown in Table 3, which also indicates the implicit annual load factors for the gas pipeline under the two different sets of assumptions.

The figure indicates the order of magnitude of the difference between the two power programs in peak-day gas requirements -- rising steadily from 1970, the year before interconnection is assumed to come into being in the 'with interconnection' alternative to a maximum difference of about 120-130 MMcf per day by 1980. Both peak and average day gas requirements of the 'without interconnection' program drop off sharply after 1980 as a result of the introduction of large nuclear units. Whereas the peak-day requirements rise steadily on the 'without interconnection' program until that time (except for the year 1972 which shows the impact of the Atomic Energy Commission's Karachi nuclear plant), the peaks fluctuate heavily on the 'with interconnection' program. The fluctuations arise from the introduction of additional hydro units in the North or new Mari units and from the expansion of the transmission line, for each of these result in the increased availability to the South of cheap base-load energy so that Sui gas fired generation plays a reduced role; as a year passes and more of the hydro or Mari energy is absorbed in the North so the plants fired by Sui gas in the South take on again a larger portion of the load. But the Sui plants remain much more in peaking service in the 'with interconnection' case than in the 'without interconnection' case and so the load factor on the gas pipelines remains much worse, though it seldom drops below about 40 percent.

The cost of providing sufficient gas transmission capacity to cope with the peaks of the 'without interconnection' case can be roughly estimated on the basis of expansion plans of the Sui Gas Transmission Company (SGTC), at about $23 million. SGTC has drawn up a number of alternative plans for expanding the capacity of the Sui-Karachi pipeline to meet anticipated needs up to 1975. These alternative plans are made up of varying amounts of compression and looping required to meet two alternative forecasts of the growth of demand for gas and under two different assumptions with regard to the pressure at which the gas initially enters the pipeline at Sui. One of the load forecasts

1/ See Appendix II for details of derivation.

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

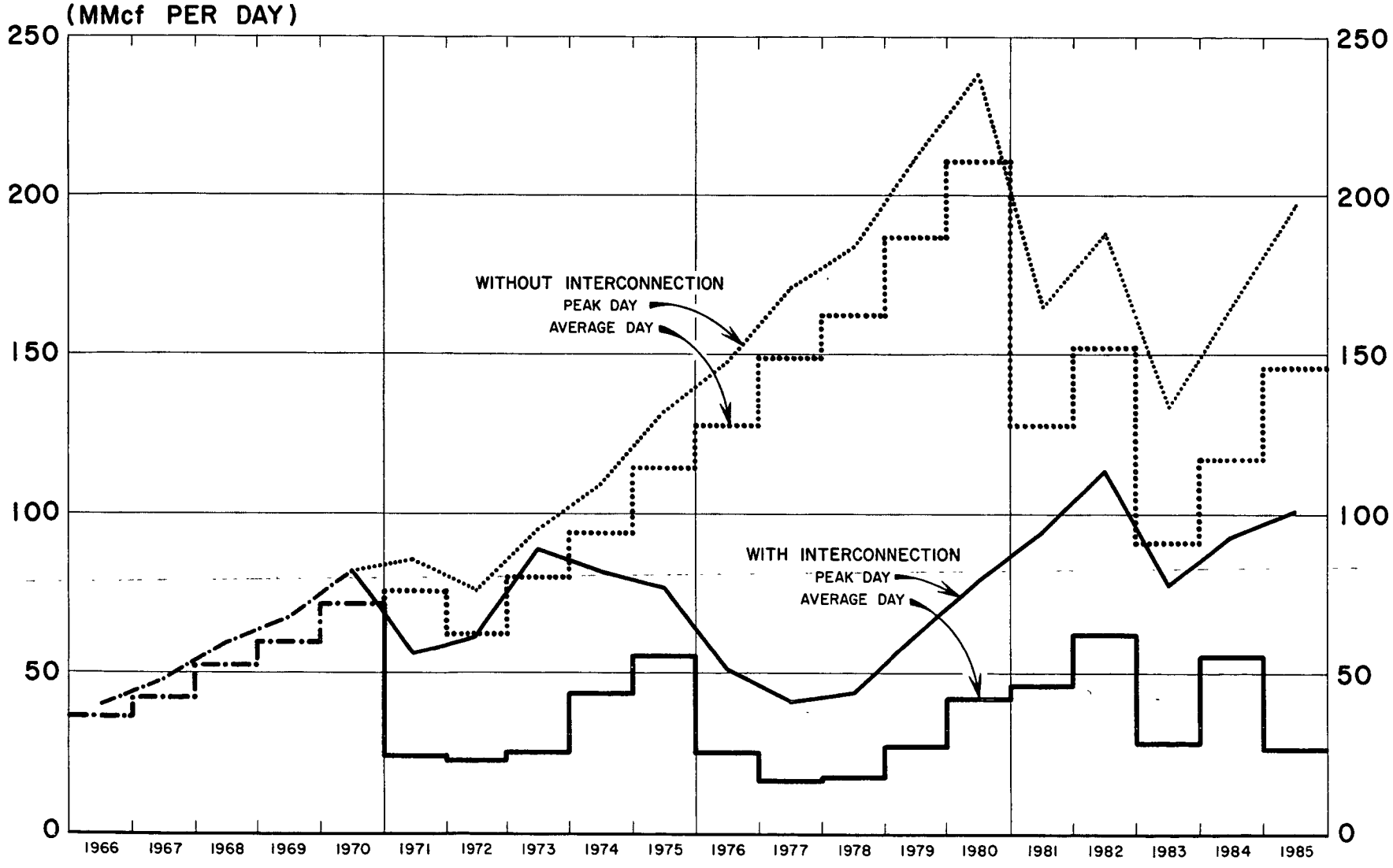


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Table 3

Requirements of Gas for Electric Power Generation in the Hyderabad-Karachi Area: The Implications of Electrical Interconnection

	Without Interconnection			With Interconnection and 1,100 mw at Mari		
	Average Day (MMcf)	Peak Day (MMcf)	Annual Load Factor (%)	Average Day (MMcf)	Peak Day (MMcf)	Annual Load Factor (%)
1966	36	40	90	36	40	90
1967	42	48	88	42	48	88
1968	52	59	88	52	59	88
1969	60	67	90	60	67	90
1970	72	82	88	72	82	88
1971	76	86	88	24	56	43
1972	62	76	82	23	61	38
1973	80	95	84	25	89	28
1974	94	109	86	43	82	52
1975	114	132	86	55	77	71
1976	128	148	86	25	51	49
1977	149	171	87	16	41	39
1978	162	184	88	17	44	39
1979	187	212	88	27	62	44
1980	210	238	88	42	79	53
1981	128	165	78	46	94	49
1982	152	188	81	62	113	55
1983	91	134	68	28	78	36
1984	117	165	71	55	93	59
1985	146	197	74	26	101	26

represents an increase of demand for gas very similar to the difference between the peak-day requirements of the two alternative power programs around 1980 -- an increase in peak-day requirements of about 120-130 MMcf. The fact that a particular set of investments is required to expand the capacity of the pipeline by about 120 MMcf per peak-day over the coming ten years does not of course mean that a similar program would be required to expand the capacity of the pipeline by the same amount in the decade 1970-80.

There are basically two means to expand the capacity of the pipeline -- addition of compression and addition of loops to the pipeline. Given a certain size of pipe existing, addition of compression can provide quite substantial increases in capacity at relatively low initial cost. But there comes a stage when further compression adds little to capacity unless the pipeline is also looped. Looping, in contrast, provides relatively small initial increases in capacity at comparatively high cost, but as more loops are added, effectively duplicating the pipeline, so the ratio of increases in capacity to increases in capital expenditure improves. Plans for expansion have to be made therefore after a careful survey of prospective loads. If SGTC did have to be ready to meet the peak-day gas requirements implied by the 'without interconnection' power program in 1970-80, then it would probably substantially alter the expansion plan that it has prepared for the period 1966-75. However, our purpose here is not to identify exactly the means by which the gas pipeline might be expanded to meet projected needs but to obtain an indicative economic cost of the investment involved. And in the long run it matters less whether the particular expansion required to meet the utilities' requirements is best provided by addition of compression or by looping, for expansion of other (non-electrical) demands would still at some stage require the one, providing the opportunity for further expansion by means of the other. Gulf Interstate Engineering Company of Houston, Texas, has actually prepared one long-term expansion program for SGTC designed to meet an overall system peak in 1985 of 380 MMcf 1/. This program is composed mainly of 20-inch and 24-inch looping -- i.e. larger than the size of loops included in the actual expansion plan for the immediate future -- and therefore requiring additional early capital outlay but producing economies in the long run. A figure of 380 MMcf for peak-day requirements in 1985 is considerably below the peak-day requirements that would be implied by addition of the electrical requirements of the 'without interconnection' power program to the projection of non-electrical requirements in Annex 4, Appendix Table II.

For these reasons we have adopted the SGTC 130 MMcf/peak day expansion program as a means of indicating the economic burden that would be involved in meeting the gas requirements of the 'without interconnection' program, but the resultant estimate should be taken as a minimum figure

1/ Gulf Interstate Engineering Company, System Study -- Sui-Karachi Gas Pipeline for Sui Gas Transmission Company Limited (May 1965).

since it fails to allow for the heavy early investment in large-diameter loops that would probably be more economic in the long run for providing such a large expansion of capacity. Table 4 shows the items required by the SGTC expansion plan, assuming an intake pressure of 1070 p.s.i.g. at Sui, rescheduled to conform roughly to what would be required to meet the peak-day requirements of the electric utilities in the absence of interconnection.

Table 4

Additional Pipeline Investment and Operating Costs Involved in Without Interconnection Case a/
(Million US$)

		Capital Cost For.	Capital Cost Dom.	O&M Cost	Total	Discounted at 8% Current Exch.Rate	Discounted at 8% Shadow Exch.Rate
1973	2 x 1100 HP compressors at HQ_3	0.7	0.3	0.1	1.1	0.6	1.0
1974	4 x 1500 HP compressors at HQ_1	2.7	1.9	0.4	7.7	3.9	6.0
	43.5 miles 16" loop Sui/HQ_1	1.5	1.2				
1975	56.5 miles 16" loop HQ_1/HQ_2	2.1	1.5	0.6	5.0	2.3	3.6
	1 x 1500 HP compressor at HQ_2	0.6	0.2				
1976	40.75 miles 16" loop HQ_1/HQ_3	1.5	1.1	0.6	3.2	1.4	2.0
1977	1 x 1100 HP compressor at HQ_3	0.2	0.2	0.6	3.3	1.3	1.9
	19.75 miles 16" loop Sui/HQ_1	0.7	0.5				
	16 miles 16" loop HQ_2/HQ_3	0.6	0.5				
1978	1 x 1100 HP compressor at HQ_3	0.2	0.2	0.7	3.0	1.1	1.6
	29.5 miles 16" loop Sui/HQ_3	1.1	0.8				
1979	45.2 miles 16" HQ_2/Karachi	1.6	1.2	0.8	3.6	1.2	1.8
					26.9	11.8	17.9

a/ For details of costs used see Appendix 9.

Thus, the evidence available suggests that to meet the gas requirements of electrical generation in the South without interconnection would require additional investment and pipeline operating expenditure of about $27 million, with a present worth of $12 million when foreign exchange is valued at the current rate and $18 million when foreign exchange is valued at twice the current rate.

Possibility of Gas Storage at Sari Sing

There is a possibility that the gas pipeline may not need to be expanded to take care of peak-day requirements. It was pointed out in Annex 4 that the Sari Sing gas field, located only about 20 miles from Karachi, is not now thought to contain substantial quantities of gas but might be usefully developed for storage of Sui gas. If that proves possible then it may be necessary to expand the gas pipeline from Sui only to the extent necessary to cope with average day requirements; peak days or seasons would be met with a draft on Sari storage. However, if it is true that Sari Sing does not itself contain large reserves of gas and therefore could only serve usefully for peaking purposes, then the difference between the with and without interconnection cases in pipeline capacity requirements would in fact be greater than if gas from Sui must be provided directly to meet daily peaks. This results from the relatively high pipeline load factor in the 'without interconnection' case, on the one hand, and the rather low pipeline load factor in the 'with interconnection' case (see Table 3). Because of this discrepancy in load factors the difference between the average day gas requirements of the two programs is considerably greater than the difference in peak-day requirements. Therefore the estimate of additional pipeline costs given above is on the low side if it can safely be assumed that Sari Sing can be cheaply developed into a storage facility.

Comparison of Total System Costs, 1965-85

With this estimate of differential gas transmission cost in hand it is now possible to go on to compare the present worth of the total economic costs of the three programs mentioned above -- 'without interconnection', 'with interconnection and 400 mw at Mari' and 'with interconnection and 1,100 mw at Mari'. Table 5 compares the costs of the programs, including differential gas transmission cost, with fuel evaluated in economic prices. All foreign exchange costs are here valued at the scarcity exchange rate. The comparison is limited to costs incurred over the 1965-85 period.

Table 5

Present-Worth Costs of Three Alternative Patterns of Energy Development 1966-85
(Million US$, economic fuel prices, shadow exchange rate)

	Higher fuel price series a/	Lower fuel price series b/
With gas transmission and no interconnection	791	759
With interconnection and 1,100 mw at Mari	785	759
With interconnection and 400 mw at Mari c/	793	763

a/ Based on the assumption that total gas reserves are limited to 7,300 trillion Btu. See Annex 5.

b/ Based on the assumption that total gas reserves are 9,500 trillion Btu.

c/ Details of the requirements of this program for gas pipeline capacity Sui-Karachi are not presented here, but the program would require about 40 MMcf/peak day more pipeline capacity by 1978 than the program with more development at Mari, and the cost of this can be estimated from Table 4 at about $5 million in present-worth terms (using the higher foreign exchange rate). Appropriate allowances for the pipeline cost are included in the two figures presented in the table for this program.

The implication of these figures is that there is little to choose between the three alternative programs as ways of meeting West Pakistan's electric power requirements over the next twenty years. The only program which looks slightly worse than either of the others is that which includes interconnection and develops only 400 mw at Mari; but even for this program the difference in cost is almost too small to be significant. It appears that the saving in thermal fuel and generating capability which are made possible by interconnection are just about offset in present-worth terms by the heavy early capital requirements of the EHV transmission itself. Or, looking at the comparison from the point of view of the 'without interconnection' case, one can say that the savings in transmission investment implicit in that program are just about offset in present-worth terms by the combined effects of the additional investment required in thermal plant and pipeline capacity and the additional thermal fuel costs. Only when the higher series of economic fuel prices, those implied by current estimates of reserves, are used does the heavier use of fuel in the 'without interconnection' program show up to its detriment.

Effect of Differential in Fuel Costs after 1985

There is, however, one significant difference between the alternative power programs which cannot show up in a comparison limited to a twenty-year period: this concerns the fuel costs that will be involved in running the equipment assumed in place in 1985 to meet the

loads of the following years. It is hard to handle this problem in a precise way without an extension of the planning period, for each month of which the computer simulation model dispatches the system. Load forecasts inevitably become more and more speculative with each year that they are pushed into the future. But the differences among programs regarding post-1985 operating costs appear to be sufficiently large, that the essentials can be caught in a rough hand-calculation. By 1985 the program without interconnection is using about 40 percent more thermal fuel than the program with interconnection and 1,100 mw at Mari. Almost all this difference results from the fact that it is impossible without interconnection to absorb as much of the hydro power as can be absorbed with interconnection. By 1985, the 'with interconnection' programs are absorbing all but about 3,000 million kwh of the energy available from Tarbela and almost all of the excess occurs in the flood months from June through September. The 'without interconnection' program indicates an excess of 6,000 million kwh in 1985; and the excess occurs in most months of the year. A small amount of the difference in thermal fuel consumption also results from the saving in gas purification and transmission fuel and losses that result from using the gas at Mari; however this is partly offset by the transmission loss involved when power generated at Mari is dispatched to the Northern or the Southern market.

In the years following 1985 the annual increments in consumption of hydro energy will be larger in absolute terms in the 'without interconnection' case than in the 'with interconnection' case because, the excess being more distributed over the months, it can be absorbed more readily as the system grows. Nevertheless, absolute annual energy costs will remain higher in the 'without interconnection' case until all the hydro energy is absorbed. We estimate that this might occur about 1994 in the 'with interconnection' cases and 1997 in the 'without interconnection' case.

A terminal correction has therefore been made to the figures presented above to allow for these varying trends in fuel cost after 1985 in the different programs. The terminal correction takes the form of projecting 1985 fuel costs for fifteen years and subtracting from them allowances for the additional hydro energy absorbed in each year after 1985 (calculated at the appropriate 1985 economic fuel price and also discounted to 1965 at 8 percent). This does not, of course, allow in detail for the greater efficiency that may be expected of thermal plant added to the system after 1985 or for the trend in post-1985 economic fuel costs developed in Annex 5. Nevertheless, it seems adequate to capture the fuel-cost implications of the systems assumed under the different programs to exist in 1985.

Table 6 presents the total system costs shown in Table 5 adjusted by this allowance for post-1985 fuel costs. The result is to show a somewhat clearer distinction among the programs considered.

Table 6

Present-Worth Costs of Alternative Programs 1966-85 with Allowance for Costs of Fuel Consumption after 1985
($ mlns, economic fuel prices, and shadow exchange rate)

	Higher fuel price series	Lower fuel price series
With gas transmission and no interconnection	854	814
With interconnection and 1,100 mw at Mari	835	804
With interconnection and 400 mw at Mari	849	815

These figures suggest that there is a clear advantage to a program which includes interconnection and substantial thermal development in the Mari area. When thermal fuel is priced at rates appropriate, given current estimates of reserves, this program shows savings with a present-worth value of about $20 million over the program excluding interconnection. The slower absorption of hydro energy without interconnection is a marked disadvantage to a program excluding interconnection. Even if fuel reserves turn out to be somewhat more plentiful the best program with interconnection still has savings over the without interconnection program with a present worth value of about $10 million. The program which includes interconnection but develops only 400 mw at Mari, on the other hand, looks decidedly unattractive. The difference between the costs of this program and those of the one which concentrates thermal development at Mari is composed of two main portions: first, the extra pipeline investment required to take gas for thermal generation to the South, as noted before the extra fuel costs involved in thermal generation in the North under circumstances where it will probably not be economic to provide pipeline capacity. It was pointed out above that fuel requirements for thermal generation in the North after 1975 have been priced at the current economic price for fuel oil delivered there. The program with limited development at Mari compensates partly for lack of Mari capacity with more thermal development in the North, though not sufficient to make the North entirely self-sufficient. As a result, it suffers by comparison with a program which concentrates thermal development at Mari from the high price of fuel in the North.

This analysis on the basis of economic prices therefore tends to confirm the doubts raised by Stone & Webster about the validity of interconnection if only 400 mw can be developed at Mari. If development has to be so limited there then it is probably better to choose the 'without interconnection' program which appears to cost much the same whether the cost is calculated in terms of economic prices (Table 6) or of financial prices (Table 2) -- and which involves a much smaller capital commitment.

Possibility of Sui-fired Plants at Gudu

However, the fact that thermal development based on Mari gas may have to be limited to 400 mw need not in fact mean that thermal development

in the vicinity of Mari must be so limited. The economic prices developed in this report imply that substantial use should be made of West Pakistan's other gas reserves for thermal generation. At present the chief reserves are in the Sui field. These may be used in the North or the South, as in our program with limited Mari development, or close to the gas field. Kuljian Corporation recommended that the best of several sites considered for Mari-based thermal generation was close to the Gudu Barrage, on the left bank of the Indus, where it could take advantage of the proximity of the river for water supplies 1/. This location is about midway between the Mari and the Sui gas fields. They estimated that the initial 45-mile 16-inch pipeline required to supply gas from Mari for a 125-mw thermal plant would cost about $5 million. This is presumably the financial cost, including duties and interest during construction. The economic cost, comparable with the cost figures used elsewhere in this report, is probably in the neighborhood of $4 million. According to the estimates of the economic cost of looping used elsewhere in this report, a 45-mile 16-inch loop would cost about $2.8 million. Assuming, therefore, that there would be no special difficulties in looping the section of the existing pipeline from Sui which crosses the Gudu Barrage, one can infer that a 125-mw thermal plant at the Gudu Barrage could be provided with an adequate supply of Sui gas for a capital cost of about $3 million. These costs have a foreign exchange component of about 60 percent.

The program which excludes interconnection envisages development of 300 mw at Mari to meet local loads. The best 'with interconnection' program has 800 mw additional at Mari. On the basis of the prices given in the preceding paragraph the discounted present worth of the costs of linking these 800 mw to the Sui field may be estimated at about $10 million (using the shadow foreign exchange rate). However, this may not necessarily be a net addition to the costs of the program. Kuljian recommended direct use of Mari gas for thermal generation without purification. It is possible that purification of Sui gas could be foregone for short-distance transmission to the Gudu Barrage. Sulphur is the main noxious element eliminated in the purification and it might be possible to protect the relatively short pipeline involved from corrosion due to sulphur at low cost. Elimination of purification facilities for gas supplies to meet the needs of the additional 800-mw at Gudu would save several million dollars in present-worth terms (taking the economic cost of a purification bank at $1.9 million/60 MMcf per day capacity, and again basing calculations on a doubled foreign exchange component). However, disregarding this possibility, and allowing $10 million for additional pipeline facilities between Sui and Gudu, we can conclude that this would significantly reduce, but it would not eliminate, the present-worth cost advantages of the program with interconnection and heavy thermal development in the Mari area over the program without interconnection.

1/ Circulating water would be taken from the upstream side of the barrage and discharged below. Make-up water for the steam cycle would come from deep wells on site. See Kuljian Corporation, "Report for Water and Power Development Authority, West Pakistan on Phase No. 1, Main Thermal Power Project, two-66,000-kw units".

While this analysis, on the basis of conservative assumptions, has indicated present-worth savings to interconnection which are positive but small and which vary according to the different assumptions made with regard to the scarcity value of fuel and of foreign exchange, it has not taken into account certain additional significant advantages which would result from interconnecting the main power markets of West Pakistan and concentrating thermal development at Gudu. 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 conservatively assumed in the quantitative analyses underlying the preceding 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 discussed in turn in the following paragraphs.

Problem of Fuel Supply for Low Load Factor Thermal Generation

If the Mangla and Tarbela Dams are drawn down every spring to meet agricultural requirements of irrigation water their capacity to provide electric power will fluctuate considerably over the year -- from a combined minimum of about 1,200 mw in April-May 1/ to a combined maximum of about 3,600 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. Analysis of the 'with interconnection' program on the power system simulation model suggests 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. Without interconnection the load factors would fluctuate considerably and they would sometimes be worse, according to the system dispatch performed by the simulation model.

It will be costly to supply fuel for low load factor operation of thermal equipment, and, because the 'without interconnection' program involves keeping the North self-sufficient in power even when the reservoirs are near their minimum levels this problem will be more acute without interconnection than with it. Figure 2 shows the peak-day requirements for thermal fuel that our studies imply will occur over the years 1966-76 with and without interconnection and it compares these peaks with those projected by WAPDA and by SNGPL. The figure presents two 'with interconnection' cases, one based on the main load forecast

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

underlying these studies and the other based on the higher load forecast prepared for the Northern Grid area. The SNGPL figures indicate the peak-day requirements of gas for power generation that SNGPL is preparing to meet. They represent the combined peaks of the Multan and Lyallpur steam stations only and are therefore not directly comparable with the so-called 'Bank Group projections'. The WAPDA projections include, besides the requirements of the Multan and Lyallpur steam stations, also the requirements of the Lahore gas turbines, which SNGPL is not committed to meet. The WAPDA projections are therefore more directly comparable with the Bank Group's projections which cover all thermal fuel requirements of WAPDA Northern Grid stations except for those of the small units presently in existence in Lyallpur and Montgomery.

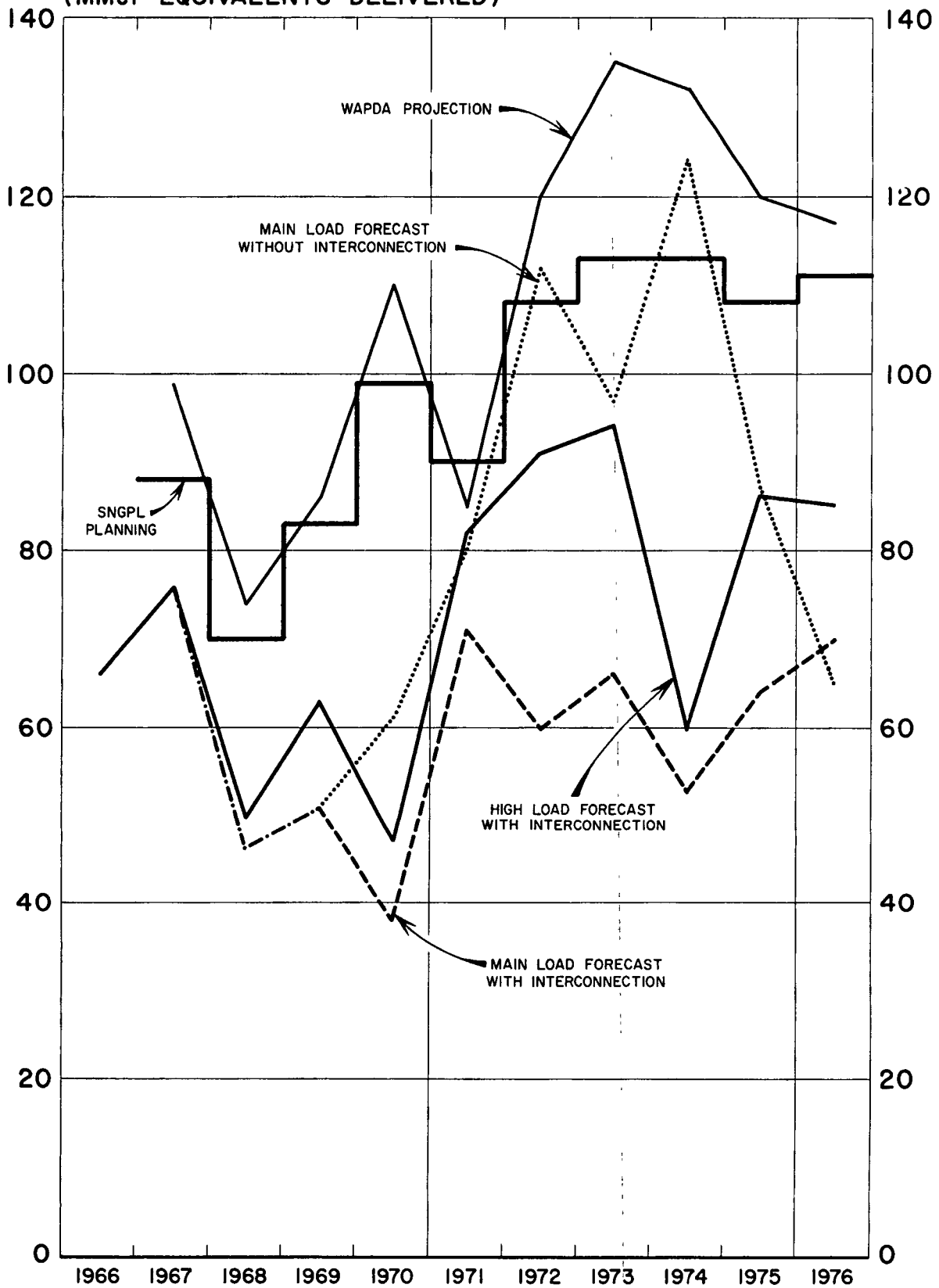
The figure indicates that the peak-days are substantially higher without interconnection than with it, and it also suggests that WAPDA may be planning for higher peaks than may in fact be encountered. In regard to the first point the figure brings out clearly the tendency that will exist without interconnection for peak-days to fluctuate much more violently than with interconnection and the tendency for them generally to be higher. With interconnection between Mari and Lyallpur in 1971 the peak-day thermal fuel requirements of the Northern Grid area will not rise above the levels of 1966-67 before the late 1970's; but if interconnection is not provided at that time than 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 regard to the second point it is striking in the figure that the highest peaks projected in these studies (i.e. those of the 'without interconnection' case) are substantially below the peaks projected by WAPDA. Yet the dispatch performed by the computer simulation model and the formula used for deriving peak-day gas requirements from it 1/ should tend to exaggerate rather than to underestimate the peaks. There should, if anything, be a possibility of using the hydro plants to a greater extent for peaking than implied by the simulation model; transfer of thermal plant from peaking service to base load might tend to raise the average load on the machine, and it would certainly raise the load factor, but it would reduce the peak.

In view of the low load factor that will apparently prevail on thermal equipment in the North, if the system is run in such a way as to absorb as much hydro energy as possible, it is an open question whether it will remain economic to supply such a large proportion of WAPDA's fuel requirements as in the past in the form of gas. To meet the full peaks of the 'without interconnection' case in 1972-74 with direct supply from Sui would involve expanding the capacity of the pipeline by about 40 MMcf/day -- at a cost of about $6 million in looping 2/. But the peak-day,

1/ See Appendix II.
2/ This rough figure is derived from the SNGPL study, Appraisal No. 3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966).

PEAK-DAY REQUIREMENTS OF FUEL FOR POWER GENERATION IN NORTHERN GRID

(MMcf EQUIVALENTS DELIVERED)



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average-day and load-factor figures which come out of the Bank Group's comparative studies suggest that this would not be the best solution. A cheaper method of meeting sharp peaks would probably be to provide gas storage facilities. But there do not appear to be any suitable storage sites in the Northern Grid area. Therefore it will probably be necessary to resort to fuel oil, expensive in foreign exchange and in costs of transport to the North, for meeting peaks and to continue to use some gas for meeting a relatively small base load. A detailed study would be required to tell exactly the shares that it would be most economic to allot to gas and to fuel oil. Nervertheless, it is possible to identify three disadvantages in this connection that would attach to a program without interconnection. The first two are illustrated in the following table which indicates the average and peak-day requirements of gas for thermal generation of programs with and without interconnection between 1971 and 1976.

Table 7

Thermal Fuel Requirements in the Northern Grid, 1971-76
(MMcf/day)

	With Interconnection		Without Interconnection	
	Average Day	Peak Day	Average Day	Peak Day
1971	15	71	23	80
1972	15	60	36	112
1973	12	66	24	97
1974	11	53	37	124
1975	11	64	14	87
1976	8	70	8	65

First, as illustrated by Figure 2, the peak days of the 'without interconnection' program are generally higher, indicating a need for larger quantities of peaking fuel and facilities (transport and storage) for making it available. Second, the average days of the 'without interconnection' case are also substantially higher, suggesting that less of the existing pipeline capacity could be released to serve the requirements of other gas consumers. And third, though not shown by the annual figures in this table, the additional requirements of the 'without interconnection' case are heavily concentrated in a few months in the year (mainly, the low-hydro months), so that most of them would in fact probably have to be met by 'peaking fuel' rather than by base-load gas. Thus, it is a marked advantage of a 'with interconnection' program, not fully taken into account in the quantitative economic analysis of the total costs of the alternative cases that it reduces the amount of thermal generation that will be necessary in the North.

The effect of interconnecting the Northern Grid area with Karachi-Sind will, of course, be 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 generally drop below about 40 percent. Analysis of the program including interconnection and concentrated thermal development at Mari indicates that peak-day thermal fuel requirements of the Karachi-Hyderabad area, with interconnection in 1971 would 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 to meet the needs of the electrical utilities, and in fact the Sui Gas Transmission Company would probably make available to other consumers, as their demands grow, pipeline capacity which became surplus to KESC's requirements. However, 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. The first reason is that 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. The second reason is that there is a chance the Sari Sing gas field close to Karachi may be suitable for cheap conversion into a gas storage facility, as discussed earlier.

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

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 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 became 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 adopted in Annex 5 is one that makes fuel prices higher over time as more is consumed and less remains for alternative non-electrical uses. 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 1,100 mw at Mari are actually about 800 trillion Btu's; those of the program with Tarbela but without interconnection about 1,150 trillion Btu's; and those of the program with Tarbela delayed to 1985 (see Annex 7) about 1,400 trillion Btu's. Thus the lack of interconnection does make quite a significant difference to the total amount of thermal fuel required and recalculation of costs in terms of a more finely tailored set of fuel prices would increase the total present-worth cost of the 'without interconnection' case above the figure used in the quantitative comparisons.

Capacity of Transmission Lines for Carrying Hydro Energy South

The discussion of the 'with interconnection' program in the preceding 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 conservatively 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. In practice, however, 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 maintenance of some additional spinning reserve in the South. Therefore analyses have also been made on the basis of the maximum capability of the transmission lines.

Figure 3 gives an impression both of the extent to which interconnection increases the capacity to absorb hydro energy into the system and of the difference that is made by assuming higher limits on the carrying capacity of the transmission lines. The figure is based on three runs of the power simulation model -- the 'without interconnection' program, the 'with interconnection' program assuming transmission lines could carry power only up to the limit of their 'firm' capability and the same program assuming transmission lines could carry power up to their 'maximum' capability. 1/ The figure indicates the assumptions that were made regarding the years when critical system additions, such as additional transmission lines, would be installed. As pointed out previously the Tarbela units are phased in much more gradually in the 'without interconnection' program because of the smaller market available for absorption of hydro-energy. The following table shows the percentage of available hydro energy absorbed in certain key years.

Table 8

Proportion of Available Hydro Energy Absorbed in With/Without Interconnection Programs

	1975	1980	1985
Without Interconnection Case			
Hydro energy available (bln kwh)	9,417	13,377	20,815
Hydro energy absorbed (bln kwh)	6,868	10,137	14,723
Absorbed as % of available	73%	76%	71%
With Interconnection Case (firm transmission capability)			
Hydro energy available (bln kwh)	10,215	20,815	20,815
Hydro energy absorbed (bln kwh)	8,285	15,525	17,753
Absorbed as % of available	81%	75%	85%

1/ See Appendix I for details of specific assumptions regarding carrying capability of transmission lines.

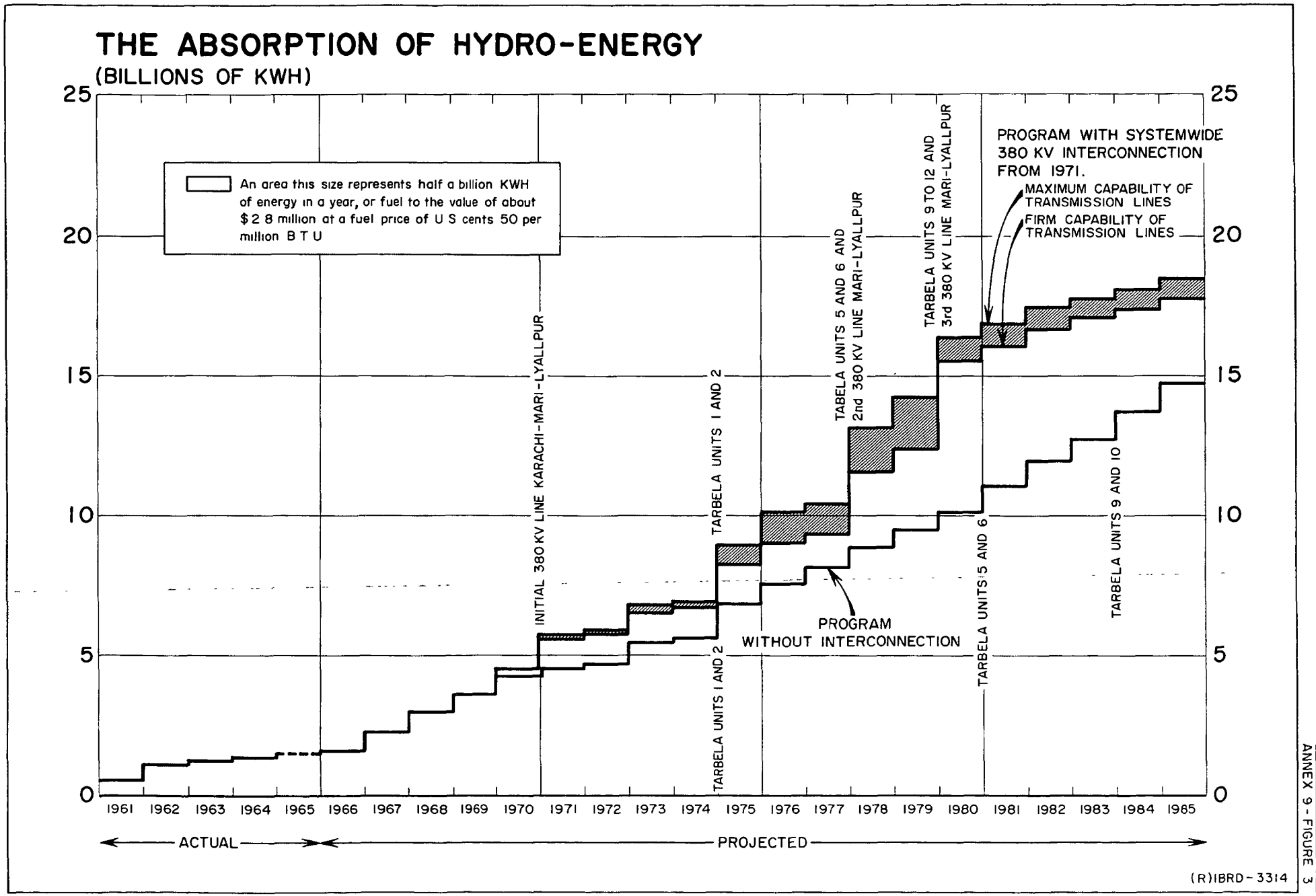
The table shows that, despite the slower phasing of the hydro units in the without interconnection case, less of the hydro energy available is generally absorbed in that program than in the other. The table suggests that, if anything, introduction of the hydro units should be postponed to an even greater extent if interconnection is not undertaken. Even with the degree of postponement built into the 'without interconnection' program used here the amount of hydro energy absorbed in different years is very much less than the amount absorbed if the system is interconnected, as Figure 3 makes clear.

The portion of the figure which particularly concerns us here is the difference between the top two lines, one indicating absorption assuming 'firm' transmission capability and the other indicating absorption assuming 'maximum' transmission capability. The differences are very large in the years 1977-79 (raising the possibility that the program might be improved by bringing in an additional line a year or two earlier in order to increase the absorption of hydro power). They are significant in all years after completion of Mangla 7 and 8 (in 1973). In practice, the transmission lines should normally be able to carry hydro energy south up to the maximum limit of their physical capability and consequently save fuel there. Some 10-15 percent of the hydro energy would be lost in transmission. Valuation of the fuel savings in the South in terms of the economic fuel price series based on current estimates of natural gas reserves indicates that they have a present worth of about $10 million; at the lower economic fuel price series, corresponding to higher gas reserves, 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 the benefits discussed previously.

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 grid there will be more room for maneuver in system operation and more flexibility. Unanticipated loads will be more readily assimilable and unexpected delays in completion of new generating plant will cause less disruption as the reserves of other parts of the system are called in to fill the gap or shortages 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

With a clear case established for systemwide interconnection in principle, the question arises when it should be initiated. The various programs including interconnection which have been discussed in this annex all included the first complete link from Lyallpur to Mari to Karachi in 1971. This is somewhat earlier than either Stone & Webster or Harza proposed. Figure 3 suggested that interconnection would begin to yield



VOLUME IV
ANNEX 9 - FIGURE 3

really large benefits in terms of the absorption of additional hydro energy about 1975 when the first units of Tarbela are added to the system. There are of course other important benefits -- such as the reduced requirement for fuel in the North and the reduction in needed generating reserves -- which would begin to become important earlier. But, if interconnection in general is worthwhile, the choice about timing would seem to revolve around the first five years of the 1970's. Therefore this problem was set up initially as a choice between 1971 and 1975, and then a number of variants were tested.

Table 9 sets out the details of the two main programs prepared for the purpose of establishing the timing of interconnection.

Table 9

Alternative Programs with Interconnection in 1971 or in 1974/75

	Northern Grid	Upper Sind	Karachi/Hyderabad
		Program A	
1970	Mangla 4, 5, 6	Mari 1 (100)	Hyderabad CT (26)
1971	Retire (15)	Mari 2 (100)	Karachi N 1 (25)
		1st Interconnection with N & S	
1972			Karachi N 1 (100)
1973	Mangla 7 & 8		Retire (15)
		2nd Interconnection with S.	
1974		Mari P (200)	
1975	Tarbela 1 & 2		Korangi 4 (125)
1976	Tarbela 3 & 4		
	(1976 critical month-March: system capability - 2541 mw; system peak - 2268 mw)		
		Program B	
1970	Mangla 4	Mari Local (2 x 25)	Hyderabad GT (26)
	Lyallpur P 1 (100)		
1971	Lyallpur P 2 (100)		Karachi N 1 (25)
	Retire (15)		Korangi 4 (125)
1972	Mangla 5 & 6		Karachi N 1 (100)
1973	Lyallpur P_3 (125)		Retire (15)
1974	Mangla 7 & 8	Mari 1 (100)	
		1st Interconnection with S.	
1975	Tarbela 1 & 2		
		1st Interconnection with N.	
		2nd Interconnection with S.	
1976	Tarbela 3 & 4	Mari 2 (100)	
	(1976 critical month-March: system capability - 2716 mw; system peak - 2268 mw)		

The reserve criterion followed in the preparation of these short-term programs was the same as that followed in devising other programs discussed in this report: 12 percent of thermal capability and 5 percent of hydro capability in each market until interconnection and thereafter 12 percent

of thermal capability and 5 percent of hydro capability on a system-wide basis. There were in addition two other important principles that were followed in constructing these alternative programs: that the Mari and Karachi-Hyderabad areas, when interconnected with the North should still not have to rely upon the North for firm capability; and that when Karachi-Hyderabad was dependent upon Mari for firm capability there would be at least two EHV transmission lines linking them. In other words the Karachi-Hyderabad and Mari areas, when interconnected, would always have sufficient installed capability to meet their combined loads though they might draw on the north for reserve capability; and Karachi-Hyderabad would still retain sufficient installed capability to meet its own load without reliance on Mari, except for reserves, until a second Mari-Karachi line had been installed. The Bank Group believes that these are properly conservative operational principles for prudent planning.

The result of observing these principles in construction of these alternative programs is that the program with postponed interconnection (Program B) ends up in 1976 with about 175 mw more installed capability than the program with early interconnection and that the second Mari-Karachi transmission line has to be introduced in this program immediately following the first. The additional capability, which is entirely in the North, would result in the North being self-sufficient for a longer time than would otherwise be the case but it would also be relatively little used since Tarbela and Mangla energy would meet virtually the full Northern Grid load in many months of the year for a least ten years after completion of the Tarbela Dam. The existence of the additional capability in the North could lead to some saving from postponement of some of the Tarbela units, but then less energy would be available for sending South. In the quantitative comparisons given below, allowance has been made for the existence of this additional capability in the program with postponed interconnection by means of a credit effective in 1981 for the saving that would then occur as a result of the reduced need for addition of generating equipment; this credit has been subtracted from the total present-worth costs of this case. The second Mari-Karachi transmission line is included in the program with delayed interconnection to enable Karachi to rely on Mari for firm capability and to bring the two programs to the same state of transmission development in the terminal year, 1976. The alternative would be to install more capacity in Karachi but this would appear to be more expensive because the second transmission line would anyway be needed a year or two later to bring hydro power from the North.

Comparison of the costs of these two programs shows that the program with delayed interconnection (Program B) is more expensive than the program with early interconnection (Program A) at all fuel prices and foreign exchange rates considered, but only slightly more so when fuel is valued in terms of economic prices, which, it will be recalled, were relatively low at this time. Program B is slightly cheaper than Program A in terms of the capital cost of generation and transmission facilities. However, this slight saving is more than outweighed by the

additional fuel costs involved in the program with delayed interconnection. The net saving of Program A over Program B is about $10 million when fuel is valued at financial prices. It is harder to define exactly the net saving involved when fuel is valued at economic prices because of the uncertainty discussed as to how the problem of fuel supply for relatively low load factor thermal generation might best be solved. It might be necessary to build pipeline capacity to meet the full peaks; more likely the peaks would be met by fuel oil and no additional pipeline capacity would be required. Alternatively it might prove most economic to construct the pipeline capacity and make it available for serving other gas consumers after the peaks resulting from delay in the EHV interconnection had been met; then a credit has to be allowed as of about 1976 for the existence of the pipeline capacity superfluous to the needs of the thermal plants. Each of these alternatives was tested, and even with the last two solutions, Program B always turned out slightly more expensive in present-worth terms than Progam A.

Apart from being somewhat cheaper than the program with delayed interconnection, the program which includes interconnection in 1971 would appear to leave West Pakistan with a technically superior power system by 1975/76. Basically the program with early interconnection ends with a geographical distribution of generating equipment which is much better balanced with the likely geographical pattern of loads than the program with delayed interconnection; the lack of geographical balance in the program with delayed interconnection will be further exacerbated as units are added at Tarbela. The heavier thermal development in the Mari area under the program with early interconnection will help to reduce instability problems in the operation of the transmission lines. It will make it easier to adhere subsequently to the present principle of providing sufficient generating capacity in the South (Karachi-Hyderabad and Mari) to meet loads in that area without involving any slowdown in the introduction of units at Tarbela. Early interconnection will make for the creation of a power system which would be easier to operate.

A number of variants on the two basic programs discussed above were tested but none had lower present-worth costs than the program with early transmission links. One test, for instance, was made of the possibility of postponing each of the two Mari-Karachi links by a year or two and bringing in the 125-mw Korangi unit 4 in 1971 to keep the Karachi-Hyderabad area self-sufficient for a longer time. With Korangi unit 4 in 1971 and the Karachi nuclear plant in 1971/72 Karachi would be self sufficient in reserves as well as basic generating capability through 1973. The first Mari-Karachi line could therefore be introduced as in Program B, in 1974 and the second in 1975. Postponement of these transmission lines would make some slight saving in capital costs but this saving would again be more than offset by additional cost of fuel, when fuel is valued at financial prices. If economic fuel prices are used for the two comparisons there appears little to choose between the two cases. The value of the saving in thermal fuel resulting from

the availability of hydro energy in the South is relatively small when calculated in terms of the economic fuel prices considered appropriate at this time and it is of the same order of magnitude as the savings in capital cost resulting from postponement of the transmission lines.

Conclusions

The fundamental conclusion of this discussion is that a power program including 380-kv interconnection between the major power markets is, assuming completion of Tarbela by 1975/76 and concentration of thermal development in the vicinity of Mari/Sui, both economically and technically superior to a power program excluding interconnection; and it also appears that, if the 380-kv system is to be installed then there are technical and economic advantages to having it earlier rather than later. Nevertheless, these conclusions require some qualification.

In the first place, the analyses described here have all been conducted on the basis of the main load forecast underlying these studies and it is likely that the conclusions drawn from them would be quite sensitive to changes in assumption regarding the growth of loads and their geographical pattern. The direction in which the conclusions might shift as a result of analysis on the basis of different load forecasts is hard to foretell because forces would be at work in both directions -- both to strengthen and to weaken the case for interconnection. The portion of the load forecast about which there seems to be greatest uncertainty is that for the Northern Grid, and a higher load forecast was developed for this area as an alternative to the main load forecast used in these studies. With higher loads in the North, more of the available hydro energy would be absorbed there and less would be available for sending South, so that the fuel savings in the South resulting from interconnection would be less significant; these fuel savings were an important factor in the quantitative economic comparison of systems with and without interconnection. However, higher loads in the North could also strengthen the case for interconnection. For instance they might make it 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, and 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, to the extent that Northern Grid loads are higher during the early 1970's than assumed in the main load forecasts underlying this analysis, the need for a link with Mari will be greater in the pre-Tarbela years.

The second qualification that must be made to the above discussion concerns the date at which initial interconnection should be implemented. The implications of the analysis are that delays beyond 1971 will result in loss of potential savings. This conclusion applies more strongly to the North than to the South because, if Mangla is

drawn down to 1040 feet each year and Warsak units 5 and 6 are postponed until after completion of the first few units at Tarbela, as recommended in Volume IV, there will be no alternative to installing additional thermal capacity in the North in order to meet Northern Grid loads in 1971/72 unless the North is interconnected with Mari by that time. As regards the South, the analysis in this Annex showed that the economic case for early interconnection between Mari and Karachi is weaker than the case for early interconnection between Mari and Lyallpur and it is also possible that progress on the Karachi nuclear unit could be speeded up so that it would become reliable more quickly than has been assumed here. Even as regards the North, however, there is somewhat more flexibility than implied in the preceding analysis. In the first place planning could proceed on the assumption of a higher drawdown level than 1040 feet in some years at Mangla (see Annexes 6 and 8) and this could serve to postpone by a year or two the need for further capacity to meet the Northern Grid load. In the second place, there is a possibility of putting in lower voltage lines which could bring some power from Mari to the North and would at the same time be useful in later years for purposes of local transmission. WAPDA apparently plans to extend the existing single-circuit 132-kv line from Rahimyar Khan the additional 40-50 miles required to link the Northern Grid with Mari. 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, according to the analysis of the Power Program in Volume IV, Chapter VII.

Another reservation which should be borne in mind in relation to these transmission studies is that the conclusions drawn from them do not necessarily apply to 500-kv transmission. As pointed out at the beginning of this chapter most of the transmission studies undertaken were made in terms of 380-kv lines. A 380-kv system would involve considerably lower capital costs in the early years than a 500-kv system. The cost savings of an interconnected system over a non-interconnected system did not appear so great in present-worth terms in this annex that they would not be seriously reduced by assuming a transmission system with larger capital costs in the early part of the period. A 500-kv system would be able to carry larger quantities of power from the hydro plants and from Mari than a 380-kv system especially in later years, but preliminary studies indicate that, with the economic fuel prices used here and an 8 percent discount rate, the savings in fuel costs which would result would be significantly less in present-worth terms than the extra capital costs involved. Nevertheless, the voltage of a transmission system is too technical a matter and the analytical approach adopted here is too simplified for these judgments regarding 500-kv transmission to be more than tentative.

There are other conclusions relating to the construction of gas pipeline capacity which can be drawn from the analysis described in this annex. The analysis raises doubts about the wisdom of expanding the capacity of the pipeline from Sui to Multan and Lyallpur in order to provide fuel for thermal generation. Figure 2 for instance, suggested that, if electrical interconnection is completed in 1971/72 and thermal

development is concentrated in the Mari vicinity, then peak-day requirements of thermal fuel for meeting the main load forecast adopted in these studies would not increase above their 1966/67 level before about 1980. The discussion around that figure also suggested that the overall annual load factor on thermal plant in the Northern Grid might be very low over the next ten to twenty years; moreover, the load would be heavily concentrated in a few months in each year (in the spring), implying that any firm base load on the thermal plants throughout the year would be small. The fact that these analyses were based on a system dispatch assuming availability of hydro capability and hydro energy as of a mean-flow year means that in some years these factors would be less important -- and average loads on the thermal plants could be higher -- while in years of high flow average loads on the thermal equipment would be somewhat lower. But consideration of these interannual hydrological fluctuations as well as seasonal fluctuations in the power capabilities of the Mangla and Tarbela units and the resultant low annual load factors on thermal equipment would only seem to raise further doubts about the validity of expanding pipeline capacity as a means of meeting thermal fuel requirements.

There may be short-term peaks in thermal fuel requirements that will arise in coming years as a result of delays in completion of Mangla units or of interconnection, but the prospect of Tarbela's completion in 1975/76 and the effect that it will have on requirements of thermal fuel in the North seem to recommend against expansion of SNGPL pipeline capacity to meet these peaks -- unless it can be done 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. The figures in Table 10, which show some of the detail derived from the power system simulation, suggest that it might be wise to consider making available to other consumers some of the pipeline capacity presently committed to WAPDA rather than to expand the pipeline system to meet WAPDA's needs. The central three columns in this table show the average-day and peak-day fuel requirements of the Multan and Lyallpur plants, in the years 1967-77, as derived from the power-system simulation study, assuming power loads of the size projected in the Main Load Forecast underlying these studies. The three columns on the right show the same data for an analysis based on the Higher Load Forecast for the Northern Grid area. And the three columns on the left show figures used by SNGPL in one of their recent planning exercises. The figures derived from the analyses described here, even those based on the higher load projection, are generally lower than those used by SNGPL. It appears 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 projections derived from the power simulation model are generally lower than those implied by the WAPDA-SNGPL figures, especially in the case 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

Table 10

Projections of Gas Requirements of WAPDA Northern Grid Plants

	WAPDA-SNGPL			Bank Group: Main Load Forecast			Bank Group: High Load Forecast		
	Average day MMcf	Peak day MMcf	Load Factor (%)	Average day MMcf	Peak day MMcf	Load Factor (%)	Average day MMcf	Peak 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	82	42	9	29	31	13	21	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

low loads. However, Stone & Webster assert in their report that, despite the close clearances of the older two turbines at Multan, they probably can be run for peaking purposes with careful operation and that the operators should therefore be trained accordingly. The figures based on the computer studies also contrast with the WAPDA-SNGPL figures in that they always indicate a higher load factor on the Lyallpur plant than on the Multan units owing to the somewhat greater thermal efficiency that the Lyallpur units should have. Besides the differences in load factors, the peak-day requirements of fuel for the Multan units as derived from the computer analysis are generally below the peak-day requirements indicated by the WAPDA-SNGPL projections; those for the two plants combined are also generally below the WAPDA-SNGPL figures, although Lyallpur peaks are sometimes higher.

As regards the Southern gas pipeline system, it was pointed out earlier 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. Figure 1 indicated that 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. They will subsequently fall as a result of introduction of the Karachi 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 some expansion of the SGTC pipeline may be needed in the years up to 1970/71 to meet the needs of KESC and the WAPDA plants in Hyderabad. However, 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.

APPENDIX I

TRANSMISSION DATA

A good deal of study has been devoted to the subject of transmission in West Pakistan. From the point of view of long-term planning the most critical questions concern EHV transmission: whether it should be introduced and when. Both Stone & Webster and Harza have recommended initiation of EHV transmission in the early 1970's. They based their studies heavily on the assumption that there was available at Mari a large reserve of low-quality gas without much alternative use. The Bank Group took the view that important alternative uses for this gas did exist -- particularly for production of fertilizers. In the middle of 1966 the estimate of gas reserves at Mari was also substantially reduced. The Bank Group wished, therefore, to reappraise the question of EHV interconnection between the major power markets of West Pakistan and to consider it in relation to the phasing of the addition of generating units at Mangla and Tarbela and in relation to the chief alternative means of energy transmission available in the Province -- gas pipelines.

For purposes of studying these problems it seemed appropriate to use a simplified approach based on the power consultant's figures and assumptions, which are not inconsistent with those of Harza. The alternative (380 kv and 500 kv) EHV transmission programs drawn up by the power consultant were broken into fragments, the parts of which could be scheduled at different times. Table 1 indicates the costs and firm capacities of the various stages of 380-kv interconnection between Lyallpur and Mari and between Mari and Karachi, each stage corresponding to the addition of a further line. The capacity estimates, which are approximations whose validity depends on a number of technical assumptions, are based upon any one line's being out of service at any time. When there is only one line in existence as in the early years the carrying capacity of the line has been taken arbitrarily as half the capacity of one line.

Capacity on the assumption of one line being out of service may be a conservative criterion where each market has sufficient generating capability to meet its own load independently and the transmission line is used primarily to bring in cheaper (e.g. hydro or Mari-generated) energy. In some programs and in some years the transmission lines would be providing firm capability; but in others they would not. Therefore some studies were made, assuming as the capacity of the lines the maximum that they could physically carry given their voltage and their length. Table 2 shows the figures adopted for maximum transmission capability and compares them with the firm capacities.

ANNEX 9
Appendix I

Table 1

380 kv EHV Transmission Lines: Costs as Used in Computer Program
(Million US Dollars)

	Domestic						Foreign						Total Domestic & Foreign
Year:	-3	-2	-1	0	1	Total	-3	-2	-1	0	1	Total	
Link 1 & 3, Lyallpur-Mari													
Stage 1, 170 mw southwards													
Line		1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals			0.2			0.2			0.8			0.8	1.0
Shunt Reactors			0.2			0.2			0.6			0.6	0.8
		1.2	4.7	1.2		7.1		1.5	6.6	1.8		9.9	17.0
Stage 2, 340 mw southwards													
Line		1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals			0.4			0.4			1.5			1.5	1.9
Shunt Reactors			0.2			0.2			0.6			0.6	0.8
		1.2	4.9	1.2		7.3		1.5	7.3	1.8		10.6	17.9
Stage 3, 680 mw southwards													
Line		1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals			0.4			0.4			1.5			1.5	1.9
Shunt Reactors			0.2			0.2			0.6			0.6	0.8
		1.2	4.9	1.2		7.3		1.5	7.3	1.8		10.6	17.9
Link 2, Mari-Karachi													
Stage 1, 250 mw to Karachi													
Line		1.4	4.6	0.9		6.9		1.8	5.7	1.2		8.7	15.6
Terminals			0.4			0.4			1.5			1.5	1.9
Shunt Reactors			0.6			0.6			1.8			1.8	2.4
		1.4	5.6	0.9		7.9		1.8	9.0	1.2		12.0	19.9
Stage 2, 800 mw to Karachi													
Line		0.9	2.7	0.9		4.5		1.2	3.2	1.2		5.6	10.1
Terminals			0.8			0.8			3.1			3.1	3.9
Shunt Reactors			0.1			0.1			0.5			0.5	0.6
		0.9	3.6	0.9		5.4		1.2	6.8	1.2		9.2	14.6

Note: Year 0 is year when transmission line comes into operation.

Table 2

Firm & Maximum Carrying Capability of 380-kv Transmission Line
(mw)

		Firm		Maximum	
		Southwards	Northwards	Southwards	Northwards
Mari-Lyallpur,	Stage 1	170	250	340	500
	Stage 2	340	550	680	1100
	Stage 3	680	1100	1100	1600
Mari-Karachi,	Stage 1	250	-	500	-
	Stage 2	800	-	1500	-

Table 3 indicates the costs of a 500-kv system and its major components. The comparable firm and maximum carrying capacities of a 500-kv system at various stages of its development are shown in Table 4.

Table 4

Firm & Maximum Carrying Capability of 500-kv Transmission Line
(mw)

		Firm		Maximum	
		Southwards	Northwards	Southwards	Northwards
Mari-Lyallpur,	Stage 1	320	630	630	1200
	Stage 2	630	1200	1200	2400
Mari-Karachi,	Stage 1	750	-	1500	-
	Stage 2	1500	-	3000	-

The costs of transmission included in Tables 1 and 3 above cover the lines themselves, related terminals and shunt reactors. There are other costs, the most important of which are the step-up transformers at the generators and step-downs from the EHV lines. The size and costs of these will vary not only with the transmission system installed but also with the generating plant installed. Costs of step-ups and step-downs at market for the Tarbela, Mangla and Kunhar units were therefore included, along with the cost of transmission to market (380 kv for Tarbela and 220 kv for Mangla and Kunhar), in the investment costs of the units themselves (see Annex 6, Appendix II). Costs of step-ups required for thermal stations and the step-downs required for bringing the energy down again to local voltage at markets were added as a special terminal correction to the discounted present-worth costs of alternative systems when interconnection was in question (see Annex 10).

ANNEX 9
Appendix I

Table 3

500 kv EHV Transmission: Costs as Used in Computer Program
(Million US Dollars)

	Domestic							Foreign							Total Domestic & Foreign
Year:	-4	-3	-2	-1	0	1	Total	-4	-3	-2	-1	0	1	Total	
Link 1 & 3, Lyallpur-Mari															
Stage 1, 320 mw southwards			1.7	6.3	1.7		9.7			2.5	9.0	2.5		14.0	23.7
Terminals				0.3			0.3				1.0			1.0	1.3
Shunt Reactors				0.3			0.3				1.2			1.2	1.5
			1.7	6.9	1.7		10.3			2.5	11.2	2.5		16.2	26.5
Stage 2, 630 mw southwards			1.7	6.3	1.7		9.7			2.5	9.0	2.5		14.0	23.7
Terminals				0.2			0.2				1.0			1.0	1.2
Shunt Reactors				0.3			0.3				1.2			1.2	1.5
			1.7	6.8	1.7		10.2			2.5	11.2	2.5		16.2	26.4
Link 2, Mari-Karachi															
Stage 1, 750 mw southwards			2.3	6.0	1.3		9.6			3.1	8.6	1.9		13.6	23.2
Terminals				0.5			0.5				2.0			2.0	2.5
Shunt Reactors				0.8			0.8				2.4			2.4	3.2
			2.3	7.3	1.3		10.9			3.1	13.0	1.9		18.0	28.9
Stage 2, 1500 mw southwards			1.4	3.4	1.4		6.2			2.0	5.0	2.0		9.0	15.2
Terminals				0.5			0.5				2.1			2.1	2.6
Moro Substation				0.7			0.7				3.0			3.0	3.7
Shunt Reactors				0.2			0.2				0.8			0.8	1.0
			1.4	4.8	1.4		7.6			2.0	10.9	2.0		14.9	22.5

APPENDIX II

THE CALCULATION OF ANNUAL GAS REQUIREMENTS AND PEAK DAY GAS REQUIREMENTS

As shown in Annex 10, the computer prints out a system operation summary of each of the two markets -- Northern Grid and South (Hyderabad-Karachi) -- for each of the 20 years of the planning period. These system operation summaries show how the system could, according to the simulation program, be optimally operated if economic conditions were those indicated by the 'financial' set of fuel prices (i.e. approximately the current structure of prices in different parts of the Province) and the current foreign exchange rate. At the other combinations of fuel prices and shadow exchange rates used for studies of gas consumption, interconnection, etc. the picture would not in fact look very different from the one printed out.

These system operation summaries give monthly plant factors for each of the thermal plants on the system, for they are the outcome of the computer's dispatching operation. The plant factors show the average load on the plant during that month as a percentage of its net capability. By summing these plant factors over a year it is possible to get an indication of total gas requirements 1/ and by considering the figures for the month in which peak use is made of thermal capacity it is possible to get an indication of peak day gas requirements. The procedures for deriving these estimates from the plant factors printed out are described in the following paragraphs.

Annual Gas Requirements

The sum of the monthly plant factors for each plant in each year indicates the extent to which the computer estimates that this plant would be required if the system were optimally dispatched. It would be possible to multiply this figure by the amount of gas that the plant in question requires to run at its full net capability 24 hours a day each day of the month (the "gas factor" in Table 1) in order to derive total gas requirements. However this would result in an underestimate of total gas requirements for a variety of reasons. In the first place the amount of energy available from the hydro units in the mean year has been exaggerated in this study by about two percent by taking it gross instead of net of generation losses and

1/ The plant factors for the plants located in the Northern Grid area and Karachi-Hyderabad may be handled directly in this way. Mari plants, on the other hand, are dispatched both to the North and to the South, and so their plant factors are derived by multiplying the plant factor for the plant in question for that month as given in the printout for the Northern Grid by the "share of Mari" figure given a few lines below, then performing the same operation for the South, and adding the two together. It should be recalled also that this represents only the plant factor incurred by the Mari plants in generating energy for "export" to Karachi and the North. Gas required for local generation must be calculated separately (see Annex 10).

auxiliary uses. Hydro energy supplies between about 50 percent and 66 percent of total systemwide electric energy requirements over the planning period and so the estimates of gas consumption should be raised a few percentage points on this account. There are also four other factors which would tend to raise annual gas requirements above those derived from direct application of the plant factor figures given in the computer printout. First, the computer model assumes optimal operation of the system, whereas coordination of such a complex system may prove extremely difficult and performance may not always reach the degree of optimality assumed by the computer. The computer program assumes that all thermal plants can be operated at any load factor, which may in fact prove physically difficult.[1] The difficulty of operating the Multan units at a low load factor has apparently led to their being run at close to full load while water was being spilled at Warsak. Secondly, the computer model fails to make allowance for the fact that heat-rates tend to deteriorate seriously at low load factor operation. If the plants were in fact operated at the high point in the load curve implied by their low plant factor, i.e. for peaking purposes, this would clearly cause gas requirements to be somewhat higher than implied by calculations based on an average heat rate. However, the heat rates used in these studies are somewhat worse than the optimal ones, making some allowance for departure from a high load factor. Moreover more precise optimization of dispatching at the time of operating the system might show that there was sufficient peaking capability available on the hydro units or on more efficient thermal plants to peak with these and to give the thermal plants which appear from the computer study to be used for peaking purposes a low but steady base load position where the lack of fluctuations in load would bring their overall fuel efficiency back to the average position used in the computer studies (or better). Thus it is uncertain whether the gas consumption has in fact been underestimated on these grounds, but it may have been. Thirdly, the computer model makes no allowance for maintenance, fully loading the most efficient units, when needed, throughout the year. This would not significantly affect the Northern Grid where there are long periods in most programs when the thermal plants are virtually out of service, but it would have an effect in the South, meaning that somewhat less efficient units would have to be brought on during short periods when the most efficient were out for maintenance. This

1/ This may be the case, for instance, with the two 62-mw units at Multan installed in 1960. Some say that they cannot be operated at low plant factors. However, the power consultant comments in this regard: "The turbines . . . have close clearances with the result that more than ordinary care must be used when starting and stopping the units, and the automatic controls only function from full to about one-quarter load. The operators consider they should be used for base-load purposes; however, after Mangla hydro units come into service, these units will be needed for peak load purposes and the operators will have to be trained to give the units the extra attention necessary." Stone & Webster, A Program for the Development of Power in West Pakistan, Volume II (May 1966), Annex C, p. 4.

could raise the average systemwide fuel consumption somewhat but its overall importance is probably extremely small. Fourthly, the computer program makes no allowance for the maintenance of spinning reserve and the generation of reactive power, needs for which will become increasingly important as the long transmission lines are installed and the widely spread-out system is integrated. These two factors together might increase fuel requirements by two-three percent.

The total effect of these various factors would appear to require increasing the estimates of gas requirements derived directly from multiplying plant factors by "gas factors" by about 10 percent. The calculations shown in the main text are made on the basis of gas factors increased by 10 percent.

Peak Day Gas Requirements

The capacity of the gas pipelines in West Pakistan is generally considered in terms of the maximum amount of gas that could be put through the line in one day. On SGTC's line between Sui and Karachi-Hyderabad, for instance, the peak-day capacity is about 110 MMcf/day (following completion of the compressor station at Nawabshah). Deliveries over a two-three hour period can be increased above the 4.6 MMcf/hour (110/24) rate that this would imply to about 5 MMcf/hour or a rate of 120 MMcf/day by means of packing gas in the pipeline. This may be done to meet the high peak, which presently occurs between 6 and 8 a.m. or to meet the rather low evening peak, but it does not alter the maximum capacity of the line under present capacity and current load pattern of 110 MMcf/day.

To gain an impression of the increase in gas pipeline capacity that would be needed by our alternative power development programs we need therefore to express gas requirements in terms of peak day needs. From the computer print-out it is possible to derive peak month gas requirements. These have been obtained by multiplying the peak month plant factor of each plant by its gas factor, as given in Table 1. For the purpose of assessing peak-day requirements no adjustment has been made such as discussed above to make allowance for maintenance, spinning reserve, reactive power, etc., since it was desired to stay on the conservative side in the estimation of gas pipeline capacity; small peaks can always be met by use of fuel oil or, as seen above, by packing in the pipeline or, possibly though more expensively, by provision of conventional underground storage or storage tanks.

The next step is to derive peak-day requirements from average-day requirements during the peak month. The relationship between KESC's peak day gas requirements and their average daily requirements in the peak month now appears to be about 1.1:1. The relationship[1] between

1/ Cf., for example, Kuljian Corporation, "Report for Water & Power Development Authority West Pakistan on Phase No. 1 Mari Thermal Power Project 2-66,000 kw units" (May 1965) Section 3, Table 32.

total electric energy produced on the peak day and that produced on the average day of the peak month is 1.12:1. That this ratio should be slightly higher is to be expected since KESC meets a portion of its peak fuel requirements with liquid fuel. If all fuel were to be supplied by gas then the relationship between peak day gas requirements and average day gas requirements in the peak month would presumably also be about 1.12:1.

It would be false, however, to project these relationships into the future for they belong to a system fueled almost entirely by natural gas. They could change if gas-fired generation were pushed lower on the load curve by substituting more fuel oil at the peak; the load factor on the pipeline would then further improve. And they could change substantially in the opposite direction if local gas-fired generation were pushed up the load curve by substituting nuclear energy, units fired by cheaper gas (i.e. Mari) or hydro energy at the bottom of the load curve. The computer studies show, as might be expected, that the latter is the case. These studies may somewhat exaggerate the extent to which optimization of dispatching will require the main gas-fired units in the North and the South to be pushed to the top of the load curve, for, as pointed out in the foregoing discussion of annual gas requirements, there may in some years be sufficient hydro or cheaper thermal capability and sufficient transmission capacity to peak with these and give the local thermal units a lower position on the load curve, where they will be less subject to deteriorating fuel efficiency. A brief inspection of the printouts raises doubts as to whether this will in fact be the case since the controlling peak gas requirements in fact generally arise in March or May in the North and in the same months in the South when the system is interconnected and it is in those months precisely that the system is very short of capacity and making full use of whatever is available at the hydro plants, Mari and the nuclear plants.[1] Nevertheless there may indeed be opportunities, in practice, for running the system in a manner which would maintain a better heat rate at less efficient plants. As far as our estimates of peak day gas requirements are concerned, the potential savings from such improved operation may well be counterbalanced by the failure to allow for any deterioration in heat rate resulting from low load factor operation which will anyway be necessary on some plants. Therefore the procedure adopted estimates peak day gas requirements without allowance for the uncertain possibility of savings from this source.

The essential problem in defining the trend of the relationship between peak day gas requirements in the peak month and average day gas requirements in the peak month is the extent to which gas-fired generation will be pushed into the top part of the load curve, so that the base from which demand for gas is fluctuating is smaller

1/ The only exception to this seems to be in some years in the South with an interconnected system; for then the peak-gas requirements sometimes occur in December when there is often considerable spare hydro capability (though not energy) and also spare transmission line capacity. If there is indeed opportunity under these circumstances for swapping hydro and local thermal usefully on the load curve then this would tend to reduce peak day gas requirements in the "with interconnection" cases and strengthen the argument in Annex 9.

than what it would be in an entirely gas-fired system. The best approach to definition of the extent of this tendency would appear to be by analysis of the proportions of total energy requirements which are supplied from different sources. Thus it is possible to define the gas base (or average day gas requirements) as equivalent to the amount of energy which is supplied from local gas-fired plants; then, if it is assumed that the relationship between peak day electrical energy requirements and average day electrical energy requirements in the peak month will remain constant and if it is assumed that peaks will be met by means of gas it is possible to estimate peak day gas requirements from average day gas requirements in the peak month.

The conclusion of this discussion may be summed up in a simple formula which was used for calculating the peak factor by which average day gas requirements during the peak month were multiplied in order to derive peak day gas requirements on the assumption that major power peaks would be met with gas.

$$\text{Peak Factor} = \frac{1.12 \times E_{pkm} - (E_n + E_m + E_h)}{E_{pkm} - (E_n + E_m + E_h)}$$

where E_{pkm} = Average day electrical energy requirements in peak month

E_n = Average day supply of nuclear energy in peak month

E_m = Average day supply of electrical energy from Mari in peak month

E_h = Average day supply of hydro energy in peak month

The values of the elements in this formula can be deduced quite readily for both the Northern Grid and the Karachi-Hyderabad area from the computer printout; the peak factors for the North and for the South can then be derived for the peak month in each year of the planning period for each alternative power program.

The higher the proportion of total energy requirements supplied by nuclear, hydro or Mari capability the higher will be the peak factor. Table 2 indicates the values of the peak factor for the three main programs studied in connection with EHV transmission (Annex 9). In the North the values range between about 120 and 220 for the program without interconnection. They are substantially higher in the program with interconnection because then the hydro units are brought in more quickly and there is greater reliance on cheap supplies of power from Mari. In the South the values range between about 112 and 120 for the program without interconnection until the early 1980's when they rise as a result of the installation

of nuclear units. Again they go substantially higher in the programs with interconnection because of the availability of hydro energy from the North and greater use of Mari energy.

Table 1

Gas Factors for Selected Plants

$$\text{Gas Factor} = \frac{\text{Capability x Heat Rate x 730}}{\text{Btu rating of gas}}$$

where 730 is average number hours in a month and Btu ratings are assumed as follows: Sui 975 Btu/cu. ft., Mari 725 Btu/cu. ft. Heat Rate is defined in Btu per net Kwh set out.

Plant	Capability (mw)	Heat Rate (Btu/net kwh)	Factor (MMcf)
Multan S1	124	11,800	1095
Multan GT	6	14,000	63
Lahore GT 1	26	18,000	350
Lyallpur S1	124	11,500	1068
Lyallpur 1	100	11,500	861
Lyallpur P	100	17,500	1310
Lyallpur 5	150	11,300	1269
Lyallpur 6	200	10,700	1602
Lyallpur 8	300	10,400	2336
Mari 1	100	12,000	1208
Mari P	200	18,000	3625
Sukkur	50	13,000	487
Karachi A	15	24,000	270
Karachi B	25	18,000	337
Karachi Bx	60	12,700	569
Karachi DF	15	11,400 (80%)	102
Karachi K1	66	11,300	558
Karachi K2	66	11,300	558
Hyderabad S_1	22	16,000	263
Hyderabad S_2	15	13,000	145
Hyderabad GT	6	24,000	108
Kotri GT	40	18,000	539
Hyderabad GT_2	26	17,500	340
Korangi 3	125	11,300	1057
Korangi 5	200	10,700	1601
Korangi 7	300	10,000	2244

Table 2

Peak Factors

	NORTH			SOUTH		
	Without Interconnection	With Interconnection & 400 mw Mari	With Interconnection & 1100 mw Mari	Without Interconnection	With Interconnection & 400 mw Mari	With Interconnection & 1100 mw Mari
1966	126	126	126	112	112	112
1967	118	118	118	112	112	112
1968	143	143	143	112	112	112
1969	147	147	147	112	112	112
1970	145	198	198	112	112	112
1971	134	140	140	113	121	121
1972	129	156	151	118	119	119
1973	139	155	160	117	129	118
1974	133	188	188	116	124	124
1975	156	182	182	115	130	130
1976	225	211	211	115	126	165
1977	193	229	229	114	124	207
1978	217	233	233	114	122	192
1979	189	282	282	114	126	195
1980	170	337	337	118	124	168
1981	210	235	390	134	130	154
1982	221	257	444	130	144	143
1983	188	186	526	157	140	190
1984	212	194	207	146	168	166
1985	210	162	258	139	142	166

APPENDIX III

UNIT COSTS OF INVESTMENT IN GAS PIPELINE EXPANSION

The following unit costs, which are supposed to be economic costs (i.e. excluding taxes, duties and interest during construction) at 1965 prices were obtained from reports kindly made available by SGTC and SNGPL.[a/]

Capital Costs	Cost (Million $)		
Looping	For. Exch.	Dom.	Total
16" loop, per 100 miles	3.6	2.7	6.3
18" loop, per 100 miles	4.7	3.5	8.2
Compressors			
2 x 1100 BHP units	0.65	0.35	1.0
1 x 1100 BHP additional unit	0.21	0.17	0.38
2 x 1500 BHP units	1.50	1.50	3.0
1 x 1500 BHP unit	1.00	1.20	2.2
1 x 1500 BHP additional unit	0.60	0.20	0.8

Operating Costs ($)

loops: $630/mile p.a. compressors (p.a.):	1100 BHP solar units	1500 BHP reciprocating units
labor and overheads	21,000	42,000
spares and lube	9,240	12,600
fuel	24,370	21,000
Total	54,610	75,600

a/ Mainly:
(1) SGTC: SGTC Expansion -- Technical and Financial Study prepared in London by the Burmah Oil Company (Pakistan Trading) Ltd., for the Sui Gas Transmission Company Ltd., Karachi, (May, 1966).
(2) SNGPL: Appraisal No. 3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966).

ANNEX 10

THE POWER SYSTEM SIMULATION MODEL

THE POWER SYSTEM SIMULATION MODEL

(This annex is bound separately, but the first few pages, which describe in very general terms the content of the annex, are also reproduced here.)

Electric power systems are characterized by complex interactions among component generation and transmission facilities. The operation and performance of each piece of equipment at any particular time is heavily influenced by the composition of the rest of the supply structure. And the choice of one unit over another for installation at the present time may influence system development far into the future. Furthermore, in the West Pakistan case, there is strong interdependence between the management of electric power and the performance of other sectors of the economy, particularly agriculture. One of the primary thrusts of this study, therefore, has been in the direction of general systems analysis of investment in electric power.

The Bank Group was most fortunate in being able to secure the services of Dr. Henry D. Jacoby, a member of the economics faculty of Harvard University, who had developed a computer simulation model for use in the planning of electric power systems.1/ Dr. Jacoby made extensive elaborations to his basic model to take account of many of the specific characteristics of the West Pakistan power systems. The result is a computer program which simulates the long-run capacity expansion and short-run operation of a major portion of what is likely to become the interconnected power grid for the Province.

The simulation model is a tool for comparing alternative programs for development of generation in each of the main power markets and EHV transmission between the markets. For purposes of the model, the Province is treated as consisting of three major markets: (1) the Northern Grid along with its sources of supply and its demand, (2) a Southern Market composed of Karachi and Hyderabad along with their loads and their existing and potential generating facilities, and (3) the Upper Sind (Mari-Sukkur area) with its potential development of thermal generation and its demand. The small Quetta system has little bearing on the questions under study, and it was not included in the analysis.

The evaluation of alternative power investment programs takes place in the context of a demand projection for each of these three markets for a 20-year planning period. In addition to these projection data, information is required on the capabilities, heat rates, and fuel, maintenance and operation (M & O) and capital costs of all existing and potential thermal and nuclear generating facilities; the capital and M and O costs of existing and potential hydroelectric developments along with monthly patterns of capacity and energy output; the capital and M and O costs and the carrying capacities of proposed

1/ See H. D. Jacoby, Analysis of Investment in Electric Power, Doctoral Dissertation, Harvard University, 1967.

transmission lines; and economic parameters such as discount rates, foreign exchange rates and opportunity costs of capital. Alternative power programs are defined which are "equivalent" in that each will meet projected demand growth in each of the three markets with an acceptable standard of service quality as evidenced by the maintenance of a certain quantity of technical reserve. The computer model is then used to compute indicators of the relative economic attractiveness of the different programs under a variety of assumptions about the values of certain critical economic variables such as the foreign exchange rate or fuel prices.

This analysis is accomplished by means of a two-part procedure: (1) detailed simulation of system expansion and operation over the 20-year planning period, and (2) an adjustment for the impact of different investment programs on system cost in the years beyond the 20-year horizon through the use of a simple terminal correction. As noted above, there is strong interdependence between the various units which are found on the system at any point in time, and in order to capture the essential operating characteristics of the system as they impinge on total cost, an approximation of the results of hourly and daily load dispatching on the system is calculated for each month of the planning period. Considerable attention was devoted to the formulation of this model of short-run operation. What is desired is an aggregative technique which captures the essential characteristics of system operation without getting weighted down with excessive technical detail and computation expense. The algorithm developed here uses the integrated load function as a basis for approximating the results of the optimal dispatching of generating units to meet an ever fluctuating instantaneous power demand.

Based upon this model of system energy dispatch, the computer program calculates fuel costs incurred in each month of the planning period, and in turn combines these data with figures for the capital and M and O expenditures implied by a particular investment schedule to produce information on the present worth of total system supply cost over the plan period. This calculation is performed for a range of values of the discount rate, the foreign exchange rate, fuel prices and opportunity costs of capital in order to allow the testing of the sensitivity of results to variation in assumptions about these variables.

At the end of the plan period there will be a collection of assets which is passed on beyond the planning horizon. The form of the final asset structure will differ according to the particular pattern of development followed during the plan period, and this difference will be reflected in a variation in the cost to serve provincial electric demand in the years of the more distant future. The second part of the analysis involves the approximation of the economic impact of differing terminal conditions by means of a set of simple functions and the adjustment of the computer results to account for these effects.

The essential feature of the computer model is its ability to calculate total system fuel costs; this aspect accounts for most of its complexity, most of the time taken in the analysis of a development program, and most of the value of the model itself. The dispatching calculations are based on monthly representations of the integrated load functions for each of the major markets. This approach is described in detail in the text of this annex. During any month, the program begins by dispatching the hydro plants in such a way as to make the best use of their capacity and energy in the Northern Market. If there is unused energy in the North, the program attempts to transmit the excess to the South. This is an iterative calculation, and the program tries to minimize the sum of wasted energy in the North plus line losses. A mandatory transmission from North to South is made in the event the Southern Market would otherwise be in shortage.

Once the hydro dispatch in the North and the transmission to the South have been completed, the program begins the dispatch of thermal units. Each market is dispatched in turn in such a way as to minimize the market fuel cost for that month. If there exists generating capacity in the Upper Sind (Mari) and if a full EHV transmission system from Lyallpur to Karachi is in place, the program must consider the possibility of transmission from Mari in either direction (provided that the line from Lyallpur to Mari is not already loaded with hydro energy coming South). Since the energy cost of Mari production may be significantly cheaper than thermal energy in either the South or North, there is a problem of optimal allocation of this capacity between the two markets. Once again the computer program goes through an iterative calculation, re-allocating the Mari capacity, subject to all the relevant transmission and market demand constraints, until the particular allocation which minimizes total system fuel cost for the month is achieved.

Performance of this system dispatch, or even an approximation to it, by hand would clearly be extremely cumbersome, and the analysis would have to be limited to one or two alternative programs. On an IBM 7094 computer, on the other hand, the complete evaluation of a 20-year development program including several separate system dispatches for each month of each year (one for each set of fuel prices) and computation of the present worth (at various different discount rates) of fuel costs, maintenance and operation costs and capital costs (with foreign exchange expenditures valued at a number of exchange rates) requires approximately four minutes; on an IBM 7090 it requires slightly longer. So long as the load forecast remains fixed, any number of alternative development programs may be simulated in a particular computer run. Thus, once the basic computer program has been prepared and data on all existing and potential system components have been drawn together, the system model may be used with reasonable ease to evaluate any number of development programs that appear to be of interest.

Besides the summary figures regarding the total costs of a development program over the plan period, the computer is 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 concerns the operation of the system in each month of the 20-year planning period. It shows approximately how the hydro 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 program turn out as they do relative to the costs of alternatives. 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. 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 more 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.

The experience of the Bank Group in the use of a computer model for simulating the operation of the power system convinced it that this type of approach has considerable potential for assisting in decisions regarding system development. The availability of the computer model made possible a depth and a range of computations that would otherwise have been physically infeasible; the depth was primarily due to the detail provided by the computer print-out regarding system operation under different development programs, while the range was due to the relative ease and speed with which alternative programs could be analyzed.

Nevertheless the Bank Group's studies far from exhaust the potential of the simulation model. There is a wide range of additional alternatives (such as alternative operations of the reservoirs and analyses with different load forecasts) which the Bank Group would have desired to cover had time been available. There are some questions -- such as the scheduling of plant retirements or the question of the amount of generating reserves that should be maintained on the system -- for which the simulation model could prove helpful but which hardly find a place in this report because the limited time available for study forced the Bank Group to set quite strict priorities. Because of the frequent changes that inevitably occur in knowledge of a country's resources and in expectations regarding loads and system developments, planning has to be a continuous process. It is because of its belief in the usefulness of the simulation model as a tool for continuous system planning that the Bank Group has included in this report a considerable amount of detail regarding the model and the way it works.

This annex, prepared in large part by Dr. Jacoby, presents this technique in considerable detail. Chapter I introduces this approach to long-run planning and discusses the different elements of the total system cost function. Chapter II describes the computer program itself -- its size, data requirements, sequence of computation and part of its print-out. And Chapter III is an explanation of the several adjustments

to the computer results which may be required in certain cases, the principal adjustment being the terminal correction.

Chapters IV through VIII are devoted to the details of the system energy dispatching routines. Chapter IV includes a derivation of the characteristics of the integrated load function and an explanation of its use in modeling system energy dispatch. Chapters V and VI contain the details of the computer algorithms developed to handle hydro and thermal dispatching respectively, and Chapter VII presents the analysis of inter-market transmission. Finally, Chapter VIII describes the monthly system operating summary which the program provides.

ANNEX 11

GUIDELINES AND TERMS OF REFERENCE

GUIDELINES AND TERMS OF REFERENCE

Table of Contents

INDUS SPECIAL STUDY

TERMS OF REFERENCE

STUDY OF ELECTRIC POWER

JUNE 5, 1964

1. The Stage II assignment on Electric Power will cover:

A. An analysis of the power and electric energy requirements of West Pakistan for the period 1965-1985 with tentative projections beyond.

B. (1) System analyses of the electric power generating program in connection with the Tarbela Project and possible alternatives on the Indus River.

(2) A study of the power potential to be developed in connection with other water storage projects which may be considered by the Bank Group after consultation with the Government of Pakistan as feasible for execution during the period 1965-1975 and those which may form the basis for development beyond 1975.

In carrying out both of these studies, consideration should be given to alternative or additional feasible conventional thermal or nuclear facilities.

2. A draft of a final report including B(1) (the Tarbela investigation) is to be completed by November 15, 1964 and a Comprehensive Report including both B(1) and B(2) by December 31, 1965.

3. In addition to the preparation of these reports, the assignment will include such other assistance as may be required by the Bank and its other consultants, in connection with the determination of the economic return of the various projects.

Scope of Assignment

4. The work to be performed by the Power Consultant will be limited to that which is necessary for the preparation of the required reports for the Bank Study, and will include the work indicated below.

General Power Market Investigation

5. Review and discuss with those responsible, all reports and other data on the existing status of power development and use. To the extent that there are gaps in the data, carry out such

additional investigations as are necessary. The specific systems and facilities to be covered would include the following:

(i) WAPDA Grid and isolated systems.

(ii) Other West Pakistan electric utilities in WAPDA's service area.

(iii) Karachi Electricity Supply System.

(iv) Industrial captive electric plants.

(v) Mechanical, as well as other power, facilities which are feasible for electrification.

6. Review, discuss and, if necessary, modify the existing long-term forecasts of the power and electric energy requirements of West Pakistan including:

(i) Review of WAPDA and its consultants' market survey practices and results.

(ii) Review of the Report of the Power Commission on potential energy requirements.

(iii) Independent appraisal, and update (i) and (ii) above.

(iv) Carry out field work to audit accuracy of surveys and update basic data, collect supplemental data to fill gaps, study in coordination with other consultants agricultural, tubewell, rural electrification, and construction power requirements, study the effect of service improvements on load growth and study prospective loads including airconditioning.

(v) Check the resulting forecasts with the best available projections from other sources, on a regional and provincial basis, of industrial, commercial, residential power requirements over the period of successive Five Year Plans. Forecast reasonable power demands by areas with division of such demands between the utility system and industrial private generation.

(vi) Analyze the load characteristics of the main classes of electricity consumers, their diversities and their seasonal adjustability.

(vii) The forecasts noted above should include a reasonable judgment as to system load factors, energy duration curves, and such other data as may be necessary to carry out system analyses in accordance with such

standard power techniques as the U.S. Federal Power Commission's procedures for calculating the benefits of power projects.

(viii) Review and comment on existing and prospective utilization facilities, the organizational requirements and indicate the order of magnitude of supporting investments and their operating costs.

The Tarbela Investigation

7. In collaboration with the Bank's other consultants, carry out such studies as are necessary to the evaluation of the power benefits of the Tarbela Project. The work would include:

(i) Review and discuss the existing studies and appraise the contribution which the Tarbela Project (broadly defined to include the power facilities of Tarbela and taking into account such off-channel storages as will be covered by the Study) could make towards meeting the power needs of West Pakistan. Review the staged development of the power installation at Tarbela to its ultimate capacity.

(ii) On the basis of data on month by month water releases supplied by the other consultants estimate the power capability and production of electric energy that can be expected from the Tarbela Project.

(iii) In conjunction with the dam sites consultant agree on estimates of the construction and operating costs of power facilities at Tarbela.

(iv) Indicate the most promising hydro, conventional thermal and nuclear alternatives to Tarbela as an electric generating project and compare their costs both in regard to installation and operation with power from the Tarbela Project. Cost estimates of feasible conventional thermal and nuclear power facilities will be prepared on the following basis:

(a) Update recently estimated thermal plant investment and operating costs.

(b) Estimate the cost of various sized thermal facilities indicating separately the foreign currency component of both investment and operating costs.

(c) Estimate the realistic heat rates applicable to the various units studied, and assess the cost of gas and other fuels including imported

oil on the basis of further instructions with respect to the methods to be applied.

(d) Prepare for similar planning purposes realistic capital and operating cost estimates for nuclear energy plants which might usefully be included in any long-term power program in West Pakistan.

(v) Prepare an estimate of investment and operating costs for the transmission system required in West Pakistan on the assumption that Tarbela is carried out. The period covered would be long enough to absorb the full potential power capacity of Tarbela. Prepare a similar estimate of investment and operating costs for the transmission system of West Pakistan through the same period on the assumption of the most promising alternative system without Tarbela. In the course of the Study, evaluate the feasibility of electric interconnection with Karachi.

(vi) Prepare the annual cash requirements for construction and operation of the Tarbela system through the period until the potential capacity of Tarbela would be fully loaded as well as for alternative systems.

(vii) Prepare an estimate of the value of power benefits from the Tarbela Project in terms of their present worth over the economic life of the project. Data on the estimated economic life will be provided by the dam sites consultant. The annual benefits will consist of the annual savings in cost, both investment and operating, achieved in satisfying the West Pakistan load requirements through the use of Tarbela power instead of the most favorable alternative.

Data to be Furnished by Others

8. To enable the Power Consultant to complete the work on Tarbela as described above, within the time limits stated, the Bank or others will endeavor:

(i) By June 1, 1964, to provide copies of all existing reports and ready access to such back-up data as may reasonably be required. Also to provide as available all economic studies, development programs, etc., which would reasonably be required for the purposes of the power market survey.

(ii) By June 15, 1964, to provide the pattern of water releases for irrigation from the Tarbela Reservoir to be used for this Study.

(iii) By July 1, 1964, to provide the pattern of waterflow through the canal hydroelectric projects as well as the water release pattern which can be assumed for the other hydroelectric projects that will be in operation by 1975.

(iv) By August 1, 1964, to provide an indication of the staged development at the Tarbela Project including such off-channel storages as will be covered by the Study.

(v) By September 1, 1964, to provide an indication of the economic life of the Tarbela Project.

(vi) By June 1, 1964, to provide guidelines on methods of cost determination including economic valuation of fuel requirements and interest rate to be used.

Comprehensive Report

9. In collaboration with the other consultants review all existing data and reports and prepare such studies as are necessary for the preliminary evaluation of the power potential of various other surface water storage projects as selected by the Advisory Committee on dam sites. This evaluation should be in sufficient detail only to serve as a useful guide to the long-term planning of hydropower development in the Indus Basin.

10. As more firm data would become available with respect to the pattern of water releases from the various storage projects the power benefits to be derived from them should be reexamined and updated on the basis of this information.

Data to be Furnished by Others

11. To enable the Power Consultant to accomplish this portion of the work, the Bank or others will endeavor:

(i) To provide up-to-date estimates of the pattern of water releases from various projects as available progressively between August 1, 1964 and August 1, 1965.

(ii) To provide data concerning hydropower potential and approximate cost estimates of such dam and reservoir sites selected by the Advisory Committee for investigation.

Schedule for Tarbela Investigation and the Comprehensive Report

12. The Power Consultant shall commence work as soon as possible after receipt of the notice to proceed but not later than June 1, 1964. A draft of a final report on the Tarbela Project shall be submitted by November 15, 1964 and a final report by December 31, 1964. The final Comprehensive Report shall be completed by December 31, 1965. Until the end of 1964, priority shall be given to the work associated with the Tarbela Investigation.

INDUS SPECIAL STUDY

MEMORANDUM TO THE CONSULTANTS
METHODS AND ECONOMIC GUIDELINES

JUNE 8, 1964

1. This memorandum indicates the method and several of the assumptions to be used by the Bank's consultants in the economic evaluation of water and power projects in the Indus Basin Special Study. The consultants should proceed in accordance with these guidelines. It is not excluded that certain additions and refinements may be required as the Study progresses.

Economic Evaluation

2. Projects will be evaluated and alternative projects compared by computing the present worth of their respective estimated benefits and costs over time stated in terms of two "cash flow" streams (the "discounted cash flow method"). In carrying out this analysis, the following considerations are especially relevant:

(a) The calculation of agricultural benefits will be based on the increase in the net value of agricultural production resulting from each project, i.e., the difference between the anticipated future gross value of agricultural production at present prices and separately, where overriding considerations justify a change, at realistically projected farm prices (price projections will be explained) with the project and without the project less the recurrent farm costs of production (also at present prices and separately, where overriding considerations justify a change, at realistically projected prices) in each case. In these calculations, the effect of subsidies and special taxes applied to specific products should be excluded both on the cost and the benefit side. For instance, export taxes would be included and import taxes excluded. Power benefits will be based on the cost of meeting a comparable power demand (capacity and energy) from the most favorable alternative system.

The Study will consider and evaluate any additional benefits (without double counting) and requirements of each development project arising from inter alia: flood control, drainage, navigation, domestic water supplies, effluent, soil conservation, forestry, inland fish industry, etc. The Study will also take into consideration as a separate exercise, an assessment of the indirect benefits that would accrue to the economy.

(b) Costs will consist of all expenditures, public and private, on goods and services which are expected to be necessary to construct and operate the project, except recurrent farm costs of production netted out in the calculation of agricultural benefits. In cases where private investment expenditures are required to achieve the purposes of the project, they will be recorded separately.

Actual costs at market prices will be used subject to the following considerations:

(i) Where serious distortions exist in market prices, an attempt will be made to estimate real economic costs insofar as it is possible;

(ii) the effect of expenditure which represent transfers within the national economy (e.g. indirect taxes such as fuel taxes and customs duties) will be excluded; and

(iii) direct taxes on Tarbela will also be excluded. 1/

(c) Depreciation on charges and interest and other financing expenses will be excluded to avoid double counting; depreciation is taken into account by the inclusion of all capital expenditures throughout the life of the project in the cost streams; and interest is taken into account by the discounting procedure.

(d) A time schedule of costs and benefits will be set up for the life of each project or for a period of sufficient duration so that its extension would make an insignificant difference in the results; each benefit will be entered in the year when it is expected to occur and each cost will be entered in the year when the expenditure is expected to be made.

Interest Rate

3. The interest rate to be used in present worth calculations should correspond to the marginal return which would accrue to the economy from alternative capital uses in appropriate fields. Because the choice of a correct interest rate is crucial for the Study and at the same time difficult to determine realistically, the Bank has instructed its Economics Department to look into the problem in detail. In the meantime, the consultants will investigate the impact on the results of the Study of different interest rates falling within a broad range. Specifically, they will repeat all present worth calculations using the following interest rates: 2%, 4%, 6%, 8%, 10%, and 12%.

1/ Although this is in contrast to general practice, this treatment in the case of Tarbela is considered justifiable as an offset against unquantifiable indirect benefits to the economy.

Exchange Rate

4. The costs and benefits of investment projects involve, directly or indirectly, foreign exchange elements which should be valued at an exchange rate of PRs 4.76 = US$1.00 (the official rate).

Labor Costs

5. The question of the real cost of labor for the purposes of economic evaluation will need to be kept under review as the Study proceeds. In countries such as Pakistan, where unemployment and under-employment rates are high, wages for unskilled labor are likely to be above their real cost. At the same time, because of local scarcity, supervisory staff hired domestically are often paid less than their real costs. Since these two factors may offset each other, at least partially, no adjustment of market rates appears necessary insofar as the construction of dams and canals is concerned. On the other hand, the farmer's own and family labor costs will be valued at zero in the study of the agricultural aspects of the projects, whereas hired farm labor will be valued at the market rate.

Fuel Costs

6. Thermal power plants which might be considered as an alternative to hydro projects in West Pakistan would most likely be fired by natural gas. As a first step, it will have to be established that sufficient natural gas will be available after considering all other economic uses for it, for firing a thermal plant of equivalent capacity. Secondly, the opportunity cost of natural gas will have to be determined considering the alternative uses of gas in fields like fertilizers, petrochemicals, liquefaction of gas, etc. The "market" price for natural gas at the well head will, therefore, be corrected to reflect its opportunity cost. Several other adjustments will also be made to reflect the real cost of gas at the site of the thermal plants: (a) appropriate assumptions about the location of these thermal plants and reasonable estimates of collection, compression and cleaning costs as well as the economic life of the pipelines, of the maintenance costs and of the rate of utilization of the distribution facilities, (b) exclusion of certain taxes and other "transfer" payments affecting market prices; and adjustment for costs along the lines of paragraph 3 above. Information on recent market prices for natural gas is contained in the Bank Sui Northern Gas Project Report already furnished to the consultants.

Power Market Study

7. For the purposes of the Study, the Bank has undertaken to provide the key economic assumptions which underlie the power market projection. Among others, these might include: (a) the growth rate of the overall economy and population; (b) the growth rate of the industrial sector; (c) the growth of power-intensive industries within the industrial sector in various parts of the country; (d) the

state of electrification of existing industrial establishments; and (e) the growth of the electric appliance market. Points (a) and (b) are covered in the Bank Economic Report (AS-106a) insofar as the present situation is concerned, but information on these and other points with regard to future trends will be furnished by the Pakistan Authorities.

STUDY OF THE WATER AND POWER RESOURCES OF WEST PAKISTAN

GUIDELINES FOR COMPREHENSIVE STUDY OF ELECTRIC POWER IN WEST PAKISTAN

MARCH 13, 1965

1. The Power Consultant shall undertake in 1965 the Comprehensive Report on the power and energy requirements of West Pakistan referred to in his Terms of Reference dated June 5, 1964, the objective of which will be to provide the Government of Pakistan with a basis for development planning in the power sector of West Pakistan in the context of its successive Five Year Plans.

2. The studies to be undertaken by the Power Consultant for the Comprehensive Report will utilize to the fullest extent possible the data collected in 1964 in connection with the report on the Tarbela Project not only by the Power Consultant but by other Bank consultants and by WAPDA or its consultants. The Power Consultant should also utilize to the extent possible any current studies by WAPDA consultants or others which would contribute to or affect the analysis of the power and energy requirements of West Pakistan in the period covered by the analysis. The Comprehensive Report will be completed by December 31, 1965.

3. The Power Consultant will not be required to pursue further studies on the economics of nuclear power generation, gas vs electric transmission or on the value of the gas from the Mari gas field; also he should not make any further studies of the Kalabagh-Dhok Pathan Project or any other alternatives, i.e., no more "with and without" Tarbela studies to revise the Tarbela power benefits.

4. The Power Consultant should assume that:

(a) The Tarbela Project will be completed before October 1974 with generating units installed as required.

(b) The Mangla Project will be completed before the end of 1967 with two generating units installed.

(c) Works for the re-regulation of the flow of the river below Warsak hydro project will be completed by the end of 1969 and the Gomal hydro project will be completed by the end of 1971.

(d) There will be an extensive program of groundwater pumping by tubewells in the Indus Basin which will require large quantities of energy. The extent and timing of the tubewell installations will be provided by the Bank's agricultural consultants by May 31, 1965 including hours of pumping by months for both public and private tubewells, seasonal variations and restricted or off-peak operating possibilities.

(e) Other consultants will provide the Power Consultant with data in accordance with the following schedule:

(i) Rate of growth of stored water requirements by May 15, 1965.

(ii) Water release patterns for Mangla and Tarbela water by July 1, 1965 and

(iii) Hydrological information, etc., with siltation, release patterns as available up to August 1, 1965.

(iv) The cost of power installations in the Gomal hydro project, in the powerhouse in Chasma-Jhelum Link canal or any additional storage projects to be undertaken before 1985 by July 1, 1965.

5. The following guidelines will be used by the Consultant in carrying out the work in connection with the Comprehensive Report. The work to be undertaken will include, but will not necessarily be limited to, the guidelines which may be changed from time to time as conditions may require. As a supplement to the assignment in the Terms of Reference of June 5, 1964, the Consultant shall:

(a) Prepare power and energy forecasts for all of West Pakistan including the Sind, Karachi and major isolated installations for the period 1965-1985, and, at the same time update previous forecasts covering the WAPDA Grid area. In updating the WAPDA Grid forecasts the Consultant should take into consideration:

(i) The points noted in his Tarbela Report, especially with respect to the load factors, the rates of load growth, etc.

(ii) The pattern of water releases developed by the agricultural consultants for the Comprehensive Report.

(iii) The agricultural consultants' estimates of the amount of groundwater pumping (particularly the monthly pumping patterns) likely

to be required in the pre-Tarbela period (1965-1974) and in the following decade and revise the previous pumping load estimates, both reclamation and private, accordingly.

(iv) Any dams planned for construction in accordance with (d) below.

(b) Prepare estimates of the number of customers in each classification and give estimates of the consumption per customer for each classification as well as the per capita consumption for West Pakistan as a whole. In addition estimate the number of people supplied with electricity in the Province. These estimates should cover the period 1965-1985.

(c) Study the interconnection of Karachi with the WAPDA Grid, recommend voltages of the transmission lines and estimate the costs of the lines and necessary substations. In carrying out this study, the present and future corporate structure of the Karachi Electric Supply Company Ltd. (KESC) shall be ignored, and its service area shall be studied for overall West Pakistan economic benefit with the assumption that acceptable agreements between WAPDA and KESC shall be negotiated to produce such benefits.

(d) Review the power potential of any dams which may be planned for construction (and endorsed by the Dam Sites Advisory Committee) during the period 1965-1985 and the advisability of installing power facilities at Gariala or other dams at which power development may be a reasonable prospect.

(e) Review WAPDA's latest planned power generation program through 1985 and recommend adjustments or changes, if any, which appear advisable.

(f) Review WAPDA's planned transmission and distribution programs -- particularly the transmission and distribution programs -- associated with tubewell development and make recommendations as in (e) above.

(g) Assist IACA with layout and costs of transmission and distribution in connection with the tubewell program and the electrification of villages.

(h) In collaboration with IACA, study the possibility of increasing the power generating capability of Tarbela by altering the water release patterns (and drawdown of the reservoir) during the critical periods for power and determine if the power benefits would offset the agricultural losses (which might be mitigated by off-peak pumping).

(i) Collaborate with the dam sites consultant, Chas. T. Main International, Inc., in determining the priority and timing of further storage projects on the Indus or its tributaries.

(j) Estimate the cost of providing generating, transmission and distribution facilities (without eliminating common items) by five-year periods 1965-1985, including import duties, taxes, etc.