WEST PAKISTAN

WATER AND POWER DEVELOPMENT AUTHORITY

REPORT ON LOAD CONTROL STUDY

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CONCLUSIONS AND RECOMMENDATIONS

i. Prices for electricity need to transmit signals to buyers and potential buyers of when and where the costs of producing increments of electrical energy are high or low. (2.02)

ii. Prices help with the task of determining priorities for investment within the energy sector and help in the allocation of capital among competing uses. (2.03)

iii. Revenues should cover costs with a margin for capital formation. (2.04)

iv. The role of electricity pricing in the redistribution of income has to be examined. (2.05 and 2.12)

v. In practice, the objectives of a pricing policy have to be compromises. (2.08)

vi. The pricing criteria that low prices are desirable because they avoid competition from other sources of energy and encourage the consumption of electricity are rejected. Instead the economic desirability of various alternatives in the energy markets needs careful examination. (2.09)

vii. Only under certain special conditions should electricity be priced at zero marginal cost. Incentives or subsidies to waste electricity should be avoided in tariff construction. (2.14-2.17)

viii. If by simplicity in a tariff is meant a price, constant in time and space, and a price independent of other appropriate economic considerations, then simplicity as an end in itself should be firmly rejected as a criterion of price-making. (2.19)

ix. Electricity prices should be flexible rather than stable. However pointless volatility and complexity in pricing impede economic signaling. (2.20 and 2.22)

x. The value of providing incentives to smooth energy consumption by means of two-part tariffs based on metered maximum demand is questioned, especially where the availability of hydroelectric power (as in WAPDA's system) is subject to sharp seasonal fluctuations. (2.31 and 2.32)

xi. Rule curves for reservoir water releases should be the consequences of economic choices that take into account the value of water for irrigation, for power generation, and for storage and later use. (2.33)

xii. Seasonal maximum demand tariffs, perhaps of the simple price-linked-to-month kind, seem worthy of serious consideration for early introduction by WAPDA. (2.35)

xiii. Voltage and regional differentials in price are worthy of serious consideration. (2.37 and 2.38)

xiv. Some pointers to the price elasticity of demand for electric energy sold during an interval are put forward. (2.41 and 2.42)

xv. The failure of many other prices to give proper signals is not an argument in favor of having electricity prices give improper signals. (2.43)

xvi. An ideal load curve is not one which fully utilizes all of the available generating capacity all of the time. Rather, it is one which rations to the highest priority uses the available capacity and associated fuel. (2.44)

xvii. The statistic "proportion lost of energy received at 11 kV" should be calculated and the use of the statistic "proportion lost of total generated" should be discontinued. (3.04 and 3.06)

xviii. The area of interest should be widened from power pilferage to revenue leakage in all its forms. (3.05)

xix. It is questioned whether the opposing resources provided by WAPDA and the legal system are sufficient to reduce pilferage quickly to an insignificant amount and to hold it at that level. (3.10)

xx. Some arrears of revenue arise where the account for electricity is disputed and the possibilities of dispute are enhanced by the inadequacy of existing metering on technical grounds in certain cases and of the meter reading and billing practices. (3.12-3.17)

xxi. The growing practice of WAPDA in installing steel or wooden boxes to enclose meters and hence to reduce pilferage is commended. (3.18-3.20)

xxii. The methods available to dilute revenue or pilfer energy are enumerated. (3.21 and Table 3.2)

xxiii. It is suggested that the use of reverse-running detents (except for the rare case of import/export metering) be discontinued in that they facilitate an alternative fraudulent practice. (3.22)

xxiv. Careful examination is needed of the problems of negative advances of meter readings as they arise in practice and the impact they are likely to have on computerized billing. (3.23-3.26)

xxv. The paperwork of the connection procedure needs to be tightened up so that new consumers are swiftly billed on the correct rate. (3.28 and 3.29)

xxvi. To improve the assessment and collection of revenue it is recommended that sufficient resources be provided of men, organizational skills, budgets, transport, accommodation and rewards to constructive staff. (3.30 and 3.33)

xxvii. The appointment is recommended of a single full time (at this task) senior manager responsible for detection, the reduction of pilferage and improvements in revenue collecting practices. (3.31 and 3.32)

xxviii. The meter testing and repair facilities should be improved. Meters should be mounted vertically if revenue is not to be lost. (3.34)

xxix. The need to study electricity demand in a systematic way is stressed. The forecasting problem is mentioned and several useful regression models are described. (4.01-4.09)

xxx. Day-of-week effects and temperature sensitivity of summer demands were explored. Summer demand on the Northern grid can be expected to increase by 30 MW or so for a 10^{o} F rise in temperature. The variable lighting component in winter is put at about 100 MW. (4.11-4.16)

xxxi. Pen recorders are not recommended for load research purposes. Special purpose magnetic tape recorders are described. One is priced at about US$ 350. (4.18-4.20)

xxxii. The popular viewpoint that studies based on (small) samples are automatically inferior to global studies is not supported. The use of probability samples is recommended. (4.21)

xxxiii. A correlation study which can be used to analyze total system demand into components, e.g. domestic, commercial and industrial, is described in some detail. (4.23-4.25 and Annex 4)

xxxiv. Billing data, now grouped as Agricultural, should be broken down to give separate figures for (i) private tubewells, (ii) public tubewells and (iii) other agricultural. (4.35)

xxxv. Stopgap research methods of discovering component demands are outlined. Fortunately in West Pakistan nearly the whole of the supply system at 11 kV consists of simple radial feeders, radiating from grid substations. Hourly demands are logged and these were collected to give estimates of the following component load curves:

(i) private tubewells,

(ii) public tubewells, and

(iii) small and medium industries.

The load curves are given for working days of each month of 1969/70, together with estimates of the monthly distribution of consumption over the year. (4.26-4.37)

xxxvi. Attempts to obtain similar data for large industrial consumers were thwarted by the feeder data being subject to tampering. Residential demand was not studied. (4.39) xxxvii. The most likely candidates for some measure of load control, perhaps by differential pricing, were held to be:

(i) private tubewells,

(ii) public tubewells, and

(iii) large industry. (4.40)

xxxviii. One of the critical features of WAPDA Northern Grid is the variability of hydroelectric capability. The capabilities of the canal plants, Warsak and Mangla are described. (5.04 and 5.05)

xxxix. The capabilities of thermal generating stations are given but maintenance difficulties are underlined. (5.06 and 5.07)

xl. It is questioned whether it is necessary for technical reasons to generate as much power at the Multan and Lyallpur thermal stations during hours of low demand. (5.08)

xli. The observed load curves are not a correct reflection of the demands on the system at prevailing prices owing to the employment of non-price rationing techniques, e.g. moratoria on new connections. In particular the daily load factors, which average between 75% and 80%, are an unlikely consequence of <u>planning</u> the efficient allocation of resources. (5.09)

xlii. There are no strong seasonal components in actual or forecast total demands and for later years the seasonality in forecast total demands becomes if anything less pronounced. (5.11)

xliii. While for the purposes of a computer study using the Bank's simulation of the West Pakistan power system it is assumed that monthly irrigation requirements are given, it is recommended that the consequences of alternative irrigation programs continue to be investigated and evaluated in terms of both their agricultural and their power benefits. (5.15)

xliv. There are sharply pronounced seasonal stresses on the system which cause costs for energy to be high at certain times. These stresses arise from the seasonality of run-off, of hydraulic heads and of water requirements for agriculture. (5.16-5.18)

xlv. Supplementary thermal electric capacity is to be loaded with pronounced seasonal patterns in the future if prices remain structured as they are now. The foundations for a WAPDA seasonal price structure are presented to show where price incentives are to be provided to encourage consumption and where they are needed to discourage consumption. (5.18-5.21) xlvi. Estimates are given of the future annual energy and power requirements of public and private tubewells. These are subtracted from the estimated total demands to give the non-agricultural demand on the WAPDA integrated system. As expected the winter lighting component was evident in this residual load. (5.22-5.26)

xlvii. The basis of the earlier recommendation (xii) that industrial consumers be charged on a seasonal tariff is illustrated. The recommendation is firmly reiterated. (5.27-5.29)

xlviii. WAPDA should also explore the possibility of introducing an optional time-of-day industrial tariff as soon as the metering and billing problems can be solved. (5.30)

xlix. Estimates are made of benefits to the power sector that would be derived from keeping each day the amounts of electric energy devoted to the operations of private tubewells unchanged while the daily time profile is altered in accordance with two different time-of-day tubewell tariffs. Tariff Plan A penalizes consumption from 16.30 to 20.30 hours whereas Plan B applies a high rate over 14 daytime and evening hours. Responses are assumed and fuel savings are estimated using the Bank's computer simulation model. Capacity savings are also estimated, e.g. an indefinite postponement of the installation of 100 MW of generating capacity. While the cost estimates are admittedly rough, the metering costs are covered at a most conservative evaluation by benefits of 8 or 11 to 1. (5.31-5.44)

l. It is recommended that WAPDA undertake an experiment. Tubewell farmers taking their supply from some especially selected 11 kV feeders should be offered a time-of-day tariff on attractive terms. Feeders, with hourly logged demands, should be selected with a preponderance of private tubewells. Demand data can be compared both "before" and "after" and between feeders subject to the experimental tariff and those not so subject. (5.45 and 5.49)

li. The importance of adequate supervision of such an experiment is underlined. (5.50)

lii. Should WAPDA be subdivided into a generating authority and a number of energy retailing organizations, or into a number of interconnected power companies, the importance of bulk-power pricing to reflect changing costs is stressed. Appropriately fluctuating wholesale prices for power can become important instruments for transmitting the generating cost messages through the retail power companies to the final consumers. (5.51 and 5.52)

liii. In principle any electrical quantity however complex the definition can be metered, but at a price. Electricity meters are remarkably versatile. (6.02)

liv. Facets of the environment of West Pakistan which are inimical to metering are high temperatures, strong sunlight, dust, tampering and poor voltage and frequency regulation. (6.03 and 6.07) lv. Given only a little care in testing, transport and installation, the usual rotating disc meter is capable of remarkable accuracy. Stress on accuracy as an end in itself can be said to be a luxury in a developing country. (6.10)

lvi. The various items of hardware, e.g. meters and timeswitches, can be exploited to give an almost indefinite number of different tariffs, though many of them would be assessed as having little economic merit. (6.11)

lvii. The prepayment meter is found useful in Britain both to avoid getting the improvident into debt and to collect "bad debts" arising from credit meters. Theft is a serious problem. An allied device is the fixed-charge collector. (6.17)

lviii. Double or triple registers of either the pointer or the roller type can be fitted to credit meters. A "rate now operating" pointer is usually fitted to show which register is being driven by the meter disc. Other methods of indicating the price change are discussed. (6.20 and 6.33)

lvix. Instead of a 4-rate or a 5-rate meter, a self-calculating meter is conjectured which would give the price-weighted energy consumed. For large industrial consumers this kind of metering might not be more complex (costly) than the present assembly of energy meter, maximum demand indicator, resetting timeswitch and power factor penalty meter. (6.21)

lx. The no-meter solution can be adopted particularly for the smallest residential consumer. The electricity bill is then based upon either the setting, or nominal limit, of the demand-restrictive device, or the connected load of the installation obtained by inspection. Load limiters (disjoncteurs) are discussed. (6.22 and Annex 9)

lxi. Temporal price variations by month or season of year can be made via the meter reading cycle, granted regular and sufficiently frequent readings. Timeswitches to signal price changes to multiregister meters are described. The importance of controlled frequency is stressed since this permits the use of synchronous spring-reserve timeswitches. These are judged to be the most satisfactory kind. (6.23-6.29)

lxii. An experiment is proposed with controlling the frequency of the WAPDA system in such a way as to make synchronous spring-reserve timeswitches keep satisfactory time. (6.29 and Annex 10)

lxiii. A variety of temporal tariffs is illustrated, e.g. day/night, restricted hour, and seasonal time of day. (6.31, 6.32 and 6.34)

lxiv. Metering for demand tariffs is outlined. A witness is needed when the demand indicator is set back to zero by the meter reader unless a cumulative demand register is fitted or a complete record of demands is automatically logged. (6.35-6.38) lxv. Double maximum demand indicators are manufactured which facilitate day/night demand tariffs. (6.39)

lxvi. Several low-cost demand pricing devices are described including the load-rate meter used for domestic supplies in Norway. (6.40-6.43)

lxvii. Remote meter reading is described. Such developments would facilitate temporal pricing but seem to be of little immediate interest to developing countries. (6.44-6.49)

lxviii. Tariffs can be based upon telecontrol. This gives the ability to disconnect, restrict, or premium-price consumers' loads at peak times by signaling over the supply network. (6.50 and 6.51)

lxix. The metering of the magnetizing component of electricity usage (power factor penalty) is described. (6.52 and Annex 11)

lxx. Price guides to the various items of hardware are given. Methods of lowering the quality of meter engineering are described to trade-off the quality of measurement for the significance of cost message. (6.55, 6.56 and Annex 12)

lxxi. Prices are charged for kWh in order to discourage their consumption. But a price mechanism is not the only method by which electricity consumption can be rationed. Physical rationing requires someone other than the users to determine priorities for the use of electricity. They would generally be willing to pay extra not to have their supplies interrupted. This excess in value of consumer's surplus is partly or wholly destroyed by a decision to interrupt supply, though the impact can be reduced by increasing the selectivity of the application of the interruption. (7.01-7.06)

lxxii. As well as all-or-nothing physical rationing, quotas of load or energy may be assigned to individual consumers or groups of consumers. These methods allow each buyer to maximize his consumer's surplus subject to the constraint but take no account of the varying surpluses between consumers and thus tend to cause inefficiency. (7.07)

lxxiii. Using an ideal price system as a substitute for physical rationing maximizes the consumer's surplus accruing to the economy. (7.08)

lxxiv. Physical rationing, under certain circumstances, may encourage a black market. (7.09)

lxxv. The need is stressed to differentiate between physical rationing, e.g. load shedding, and price rationing where the hardware involved, such as telecontrol and load limiters, has only the overtones of physical limitation. (7.10)

lxxvi. Matters allied to physical rationing are briefly discussed. These are risk of failure, system collapse, cost of interruptions, and quality of supply. Ground rules are being sought in the provision of "adequate" electricity supply taking into account the loss of social product or consumer's surplus consequent upon an imperfect supply. (7.11 and 7.12)

lxxvii. Global load reduction by reducing voltage and reducing frequency, and selective load reduction by tripping feeders, perhaps in rotation, are mentioned. The possibilities of assisting selective load reduction by various technical devices are described. These are under-frequency relays, no-volt relays, telecontrol and timeswitches. (7.13-7.22)

lxxviii. Cooperation of large industries and public tubewells in load staggering arrangements can be sought. It is questioned whether WAPDA is successful in securing full cooperation and whether records are kept. A central organization responsible for enforcement is thought worthwhile. Another rationing method is to make use of the kWh meter and to apply a penalty price for using more this year than last. (7.23 and 7.24)

lxxix. Telecontrol, or signaling over the supply network, is described in some detail. The cost of hardware is given as:

Injection equipment	US$ 750 per MVA of system demand
Receiver	US$ 35 per controlled supply

These costs are compared with the cost of providing timeswitches at US$ 40 per controlled supply for a roughly equivalent duty. The breakeven density of application is given by a naive calculation as 750/(40 - 35) = 150 receivers per MVA of system demand. An alternative view which leads to a breakeven density of 10/MVA is discounted. (7.27 - 7.38 and Annex 13)

lxxx. Perhaps a more stringent view should be taken of telecontrol in a developing country in that successful operation is questionable, especially with uncontrolled frequency. Poor voltage regulation and high energy losses for the power frequency equally and adversely affect ripple signals. The problem of interference by spurious signals or "noise" is discussed. (7.39 and Annex 14)

lxxxi. Radio control looks promising but the economics are not understood. (7.40)

lxxxii. The question whether load limiters, which limit individual demand, have any significant impact on group demand is left unanswered. It is inferred, however, from some British load research experience, that the "obvious" assumption that limiting individual demand reduces investment in system capacity should not form the basis of investment in load limiters without substantiating measurements. However, for residential consumers using only electric lighting, load limiters could be used to restrict the growth of demand. Owing to the high starting currents taken by motors, they seem to have no application to tubewells. (7.49 and 7.50) lxxxiii. Investment in hardware physically to ration consumers is only worthwhile if the social costs with unselective shedding exceed those with selective suppression (load control) by a margin greater than the cost of the hardware. As an opinion-forming guide, the following ranking of load-control schemes is put forward:

Price rationing with temporal pricing.

Price rationing with existing metering.

Unselective load shedding.

Selective load shedding using timeswitches or telecontrol.

Restraint by load limiters. (7.52-7.56)

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1. INTRODUCTION

1.01 The starting point in this study is the interest of the Bank in the responsiveness of power demands in a developing country to pricing policy and other commercial arrangements and the feasibility and effectiveness of controlling the load through engineering devices. 1/ This brings out the two main threads of the enquiry:

a. power pricing and

b. physical rationing

1.02 Normally those who operate electricity supply systems are concerned with the provision of adequate supply to meet a "given" demand. The pricing policies are seen as secondary to the main business of providing electricity and these policies have, as generalizations, the twin aims of raising sufficient revenue and promoting the use of electricity, coupled with the working rule that tariffs should be simple. As exceptions, though important ones, some of the advanced countries have introduced temporal pricing to reflect relative scarcities and abundances of electricity supply at different times.

1.03 West Pakistan and specifically the supply area of the Water and Power Development Authority (WAPDA) was selected for this study. WAPDA has been experiencing difficulty in meeting the demand on its system for various reasons, including shortage of capital in the face of rapidly growing load, and the quality of service has been low. Moreover, the pattern of system capability is changing with the growing amount of storage hydro capacity, leading to wide seasonal variations in the costs of supplying the peak demand. It was desired therefore to examine the extent to which the shape of the load curve might be altered, by commercial arrangements or other devices, to match the changing pattern of supply. However, in carrying out the study a wider audience was kept in mind since the Bank would then be enabled to provide better advice to borrowers facing similar difficulties. Hopefully some of the material will be useful to public utilities in general. In consequence of this recognition of a wider audience, the material as presented will be found sometimes to be advice or comment related more or less directly to WAPDA and sometimes to be of a more general nature.

1/ The material paragraphs from the Terms of Reference are given in Annex 1.

1.04 The main tasks to be covered during the study were set out in the Terms of Reference as follows:

a. to identify loads which might be adjusted in response to differential pricing or other commercial arrangements such as supply agreements with a load cut-off or contingent load shedding (with or without warning). This will involve detailed discussion with selected consumers (industrial, commercial and agricultural) and investigation of the alternative types of power consuming equipment and of energy available to them;

b. to estimate the magnitude and timing of changes in the global pattern of power demand which might result from the application of such pricing or other commercial techniques;

c. to develop data on the costs of power supply at different times of day and seasons and in different areas. (A computer model in the Bank of the WAPDA system will help in generating information about bulk supply costs for different shapes of load curve under different reservoir conditions and you should obtain data in Pakistan on transmission and distribution costs);

d. to review the various technical methods of load control, such as off-peak metering, ripple control and load limiters, with particular reference to the costs and feasibility of applying them in the WAPDA system;

e. to determine whether the savings from the adoption of the load control measures referred to in a. and d. above would outweigh their costs;

f. to make recommendations regarding the specific measures which should be adopted by WAPDA to adjust demand to system capability, and how these measures should be implemented.

1.05 Of these tasks, the identification of loads which might be controlled by price responsiveness or other arrangements was carried out by recognizing that agricultural pumping loads could be interrupted for a few hours with perhaps an insignificant loss of social product. Also interviews with industrial consumers suggested that a long-term adaptation to temporal price differentials for electricity could be expected. Only limited attention was paid to the domestic and commercial classes of consumer, particularly during the period of fieldwork in West Pakistan, though it was noted that the electricity usage per metering point was so low as to make any expenditure on metering or control devices nugatory. However, this is not to say that growth of demand cannot be expected from these classes of consumer and that they may be safely dismissed from such considerations in the future. Also both the discussion in Chapter 2 on pricing principles and that in Chapter 7 on physical load control embrace these classes of consumer in the sense of laying down general principles. Furthermore, many of the metering devices of Chapter 6 have most commonly been employed for residential tariffs. In consequence, in a general rather than in a specific way, the smaller consumers have received some attention.

1.06 Items b. and c. of the Terms of Reference were carried out exclusively with relation to the agricultural pumping load. A wealth of material was available for study owing to the importance of agriculture to the economy of West Pakistan and hence detailed and sustained attention had already been paid to the use of tubewells by previous consultants. These data were supplemented by daily demand patterns of tubewells for each month of a year. No claim could possibly be made that farmers will behave in such-and-such a way with regard to the advancement or postponement of a pumping need when faced with a supply interruption or a high-price period for electricity. Even so, plausible responses were assumed which permitted the computer model in the Bank of the WAPDA system to be run with simulated responses to load control schemes applied to agriculture.

1.07 The review of technical methods of load control presented little difficulty from the viewpoint of assembling material relevant to the favorable environment of, say, a European electricity supply system. However, it was felt that the difficulties of application of these methods in the power systems and climates of, say, Asia were imperfectly understood and required further investigation. Nevertheless some attention was paid to the more obvious unfavorable aspects of the "environment", namely heat, lack of controlled frequency, and tampering.

1.08 This assemblage of technical devices was also costed so that item e. of the Terms of Reference could be discharged though, of course, the cost estimates lacked the background of proven experience of the devices on the WAPDA system. However, the balance of estimated saving on generating investment and expenditure on fuel, less the estimated cost of metering, came out clearly favorable to temporal pricing of private tubewells once the basic assumptions have been shown to hold by a controlled and monitored experiment. The alternative of recommendations for specific, implemented actions, as implied by the Terms of Reference, was not thought realistic. Clearly the fairly limited experience of temporal pricing in France and Britain 1/ was hardly a safe basis on which to predict the impact of such pricing in West Pakistan.

1/ Limited with regard to the organization of the supply authority and the social and cultural backgrounds of the communities.

1.09 More generally the consultants' approach to the wide-ranging investigation proposed by the Terms of Reference can be seen to be a progressive narrowing of the study to focus eventually on the most promising proposals. These proposals will, it is hoped, be examined by WAPDA critically bearing in mind:

a. local first-hand knowledge

b. the likely gains to the economy of West Pakistan

1.10 The study was in the main carried out over the period of mid-May to November, 1970. As a preliminary, May was spent in the Bank in Washington discussing the ways of approaching the study with members of the staff, reviewing available information and hence formulating a shopping list of data and views of officials that should be sought in Pakistan. The months of June and July were spent in Pakistan, mainly in Lahore and in the headquarters of WAPDA, but with visits to Rawalpindi to obtain the views of the Planning Commission and other branches of central government, and to Karachi to see whether the agricultural advisers of West Pakistan had any advice to offer on the control of electricity usage for the agricultural pumping load.

1.11 As other observers had already noted "hard" data are not readily available in West Pakistan, but even so the two months spent in that country did permit some load research (i.e. research to discover demand patterns of electricity usage) to be both planned and completed. While these particular data were found to suffer from the usual defects of numbers collected by hurried field work, they remain a very useful description of the origins of the demand on the WAPDA system and provide the factual basis for the consideration of load control schemes. Another activity was to interview industrial consumers to discover whether they would be likely to respond to electricity pricing pressures of a temporal nature. At the same time their views were obtained on the quality of electricity supply and how this affected their production of goods.

1.12 Of course much of this period in Lahore was taken up with discussions with WAPDA officials. They were most helpful and courteous, though owing to the lack of coherent statistical data covering the various aspects of electricity supply, progress was often slow. Visits were made to District Offices, Accounts Centers, a meter testing station and a detection squad. During these visits the guiding principle was to seek a sufficiency of evidence to permit an admittedly rough judgment to be made as to whether the views were personal and local or could have a wider applicability.

1.13 The final months, subject to other commitments of the consultants, were spent in the Bank analyzing and reconciling the views and data collected during the fieldwork. At this stage some specific load control schemes were examined using a computer model in the Bank of the West Pakistan power supply system. As already mentioned, this permitted a view to be put forward that load control of private tubewells by temporal pricing was worthy of serious study and experimentation by WAPDA.

1.14 Simultaneously the hardware necessary for load control and temporal pricing was described and costed. Difficulties with revenue collection at present experienced in West Pakistan were particularly noted, from the viewpoint that differential pricing with its associated more complex metering would not ease these difficulties. Physical rationing, that is without involving the price mechanism, was also studied.

1.15 In describing the various meters, timeswitches, relays and so on, the aim was to facilitate understanding by economists and administrators of what these items of hardware could do, rather than to give a technical account to a limited audience. However, the report is visualized as having readers of disparate engineering knowledge, and in consequence the descriptions cannot be expected always to strike the right note for all readers. An almost identical apology could be made to theoretical economists with respect to the account of pricing principles where again the aim was to reach a wide audience.

1.16 The experience of many other electricity suppliers was drawn upon. Visits were made to the Electricity Council, London, and to Electricite de France, Paris. Also by correspondence the views were sought of Midlands Electricity Board, England, and the East African Power and Lighting Co. Ltd., Nairobi, Kenya, who are operating telecontrol installations, and of the Detroit Edison Company, who have a radio-control installation. The Long Island Lighting Co., New York, assisted with some error measurements on out-of-vertical domestic energy meters. Perusahaan Listrik Negara (PLN), Djakarta, Indonesia, and Tokyo Electric Power Co. Inc., Japan, gave details of their use of load limiters. The Pakistan Institute of Development Economics, Karachi, kindly gave access to their many studies of the use of irrigation and agricultural pumping. Allied information was obtained from the Indus Basin Review Mission, IBRD Report by Consultants, June 1970. In September 1970, a major conference was held in Cannes, France, of the International Union of Producers and Distributors of Electric Energy (offices in Paris) at which several papers were presented of assistance to this study. Harza Engineering Co. Inc. of Lahore (and Chicago) deserve special mention for their generous help in the field. All these and many others are warmly thanked for their assistance, advice, access to research reports and data and so on, which have helped, we hope, to give this study direction distilled from experience. Finally, grateful acknowledgement is made to the many officers of WAPDA who gave so much of their time.

2. ELECTRICITY PRICING PRINCIPLES

Criteria for Electricity Prices

2.01 Where and when electricity will be utilized in an economy depends in a fundamental way on the prevailing electricity price structure and on the prices that are anticipated for the future. Pricing policies for electric energy need therefore to be an integral part of the development plans for the electric power sector and of an overall energy policy defining the relationship between the development plans for the various components of the energy sector of an economy. Although this point of view is readily accepted all over the world by economic planners and others who attempt to view the economic system as a whole, those who have charge of the specific enterprises within the energy sector usually have a narrower perspective. And in electricity supply undertakings, planners with strong technical orientation often lack sensitivity to broad economic and commercial considerations and occasionally even overlook completely the relationship between electricity tariffs and the patterns of electricity demands.

2.02 Pricing plans for electricity need to meet several tests. First of all, the prices need to transmit signals to buyers and potential buyers of electricity that convey information about its cost. When and where the costs of producing increments of electrical energy are high, prices for energy should convey this information by reflecting such high costs in high prices. On the other hand, when and where incremental costs of electric energy are low, low prices should reflect this information also. For example, a pricing policy that allows hydroelectric energy to go to waste during the night for some parts of the year in a country where the overall demand for electric energy far exceeds the capacity and resources to produce it, clearly is a pricing policy that fails to convey the cost message to consumers that incremental electric energy at such times and places is very cheap indeed. Similarly, a pricing policy that does not discourage consumption of energy during those weeks of the year in which hydroelectric capability is at a minimum and during which incremental energy has to be generated in thermal electric generating units also fails to signal the cost message that this electric energy is expensive and possibly not worth the cost.

2.03 At the same time that cost messages about relative costs are signaled via prices to users of electricity who may or may not be responsive to them, prices also help to perform the task of determining priorities for investment within the energy sector and help in the allocation of capital among competing uses generally. Clearly, it is inappropriate to calculate rates of return based upon demands for electric energy that are themselves the consequence of inappropriate prices. Even the answer to the question of which of a number of alternative investments is the cheapest from the overall economy's point of view turns out to be irrelevant if the time pattern of demand with which the investment is to cope is one which comes from inappropriate signals to consumers.

2.04 In addition to transmitting cost messages to consumers and value messages for investment planning, electricity prices have two further functions to perform. The first of these derives from the fact that for the electricity supply undertaking electricity prices or tariffs are usually the major source of revenues covering costs. Also in less developed economies where capital markets and other institutions for mobilizing savings are often poorly developed, energy pricing can be a significant method for generating the savings for expansion of the electricity industry, of other segments of the energy sector, or of the economy generally. Of course, in an economy where such institutions as capital markets and taxation systems for channeling savings into investment are highly developed, less importance attaches to the requirement that revenues cover costs with a margin for capital formation.

2.05 The second of these additional functions of electricity prices derives from the fact that, often in developing countries, the distribution of income is considered inequitable. 1/ Thus electricity prices themselves are judged to be "fair" depending upon whether they help redistribute real income in the direction of groups considered "worthy". If electricity prices were to reflect resource costs correctly to all users, at all places, at all times, then the income redistribution resulting from the electricity price structure would be nil. 2/ On the other hand, if prices do not reflect costs, then groups paying more relative to cost have real income redistributed in the direction of those who pay less relative to cost. In developing economies, particularly, tax and welfare systems often function poorly. Here public utility prices can help contribute to an equitable distribution of income. Thus, it is desirable to evaluate the "incidence" of electricity tariffs as one would the incidence of taxes, at the same time that one considers their role in signaling relative scarcities.

2.06 From the point of view of the consumer the prices relevant are those which include any taxes that might be added to electricity bills. Such taxes seem to be quite common, as the survey summarized in Annex 2 indicates. In West Pakistan the rates of Electricity Duty, as the tax is called, are quite substantial. Residential consumers pay 2 paisa per kWh. This compares with a price, net of the tax on electricity, of

25.0 paisa for the first 20 kWh per month
16.0 paisa for the next 230 kWh per month
13.5 paisa for the remainder,

1/ This discussion of equity does not embrace the view by which a tariff is considered equitable if it can be defended successfully at a regulatory tribunal.

2/ Granted that other fuel prices also correctly reflect resource cost. Actually the theoretical economist would wish to emphasize that this statement is strictly correct only if there are constant returns to scale and long-run equilibrium is attained.

although residential consumers consuming 20 kWh or less are exempted from the tax. Commercial customers pay the same 2 paisa per kWh duty. It amounts to 8% of the flat 25 paisa per kWh rate. Other consumers (agricultural, industrial, and bulk) pay at the rate of 0.5 paisa per kWh.1/ This compares with 6 paisa paid for marginal kWh by agricultural consumers, 7.0 to 8.5 paisa paid by large industrial and bulk consumers and 15.5 paisa per kWh paid by the smallest industrial customers.

2.07 For an electricity enterprise dependent on the government for capital funds, it seems to be a controversial question as to whether revenues inclusive or exclusive of electricity duties should be used in the evaluation of the tariff structure. Clearly, however, it is prices inclusive of taxes that are relevant for the determination of the effects of prices on consumers.

2.08 It should be clear from this discussion of electricity pricing policy that the roles that electricity prices are called on to play are as a practical matter likely to be in conflict with each other. Only in the idealized world of theoretical welfare economics can these roles be fully reconciled. In practical situations where the pricing decisions have to be reached, the objectives of a pricing policy have to be compromises -- parts of one objective must be traded-off for parts of another. A good public policy here, as everywhere, will attempt to evaluate as explicitly as possible the gains and losses from the decision. Changes in electricity prices should be evaluated in terms of the criteria outlined above.

Criteria for Electricity Prices Rejected

2.09 Other criteria for electricity tariff policies are suggested from time to time. For example, the principle that a reduction in rates is desirable because "it will avoid competition from other sources of energy such as gas, diesel oil, coal, etc." or that "it encourages additional consumption of electric power" has been advocated in Pakistan and elsewhere in these or similar phrases. Such propositions seem to have wide appeal to managers and consultants to electric utilities whether privately or publicly owned. The view of this study is that they are faulty as general propositions even if the incremental revenues from lower prices cover the incremental costs. Prevailing market prices quite generally cannot be counted on to signal correctly the economic desirability of various alternatives. Whether electric energy, some alternative energy source, or none at all, is best at a particular time and place requires planning and examination of the alternative uses to which energy resources and the related capital and foreign exchange can be put.

1/ There are exemptions from the tax for religious institutions and governmental agencies. Self generation by consumers is taxed (plants with capacity below 2.5 kW are exempt) and unmetered consumption is taxed according to a special formula.

2.10 The Report of the Power Commission, Government of Pakistan, (July 1953), expressed the following principle:

> We feel that in order to ensure cheap and abundant power supply in Pakistan, the basic approach should be not to regard electricity as a direct source of revenue but as a producer of revenue in the form of taxes on the goods and services produced. If this approach is adopted, we recommend that the agencies in the public sector ... should so adjust the power rates as to enable them to work on a "no-profit-no-loss" basis ...

The same view was recorded again in almost identical words by a Member of the Ad Hoc Advisory Board for Power Rates on WAPDA Electricity Tariffs (Lahore, May 1969), but at that time this principle does not appear to have been accepted.

2.11 Such a principle has a number of deficiencies. First it implicitly rejects the idea that prices need to signal relative scarcities. Second, since the overall demand for electric energy per year is probably not highly responsive to changes in the average price level of electricity, particularly when average prices of substitute fuels are changed proportionately, electric energy together with the substitute energy sources may carry surcharges in the form of prices exceeding costs without imposing on the economy the excess burdens resulting from an uneconomic substitution among energy sources. Third, administratively, in a country like Pakistan, it is much more efficient to collect revenues on the basis of electricity meter-readings than on the basis of individual taxation records of the more than one million customers of WAPDA. Even though, as this report demonstrates later, WAPDA has considerable difficulty in metering and collecting appropriate revenues for metering electricity it delivers, these difficulties seem small compared to those of collecting taxes from all those who buy electricity and who buy the products that embody the electricity. Fourth, this principle fails to separate the energy sold to residential customers which may be priced according to an "ability to pay" criterion - with higher average prices for the wealthy than for the poor. 1/

2.12 Another view expressed by EBASCO Services, Inc., consultants to the Power Commission, expressed also by the Commission itself, is that "in a well-designed rate structure, each class of consumer generally pays its own way and is not an undue burden on any other class". If by classes of consumers is meant consumers at given locations using similar mixtures

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1/ Since consumption of electricity and income are positively related, this can be achieved with marginal prices above average prices. Also fixed charges or energy block sizes can be assessed according to measures related to the value of dwellings, etc.

of expensive and cheap electricity and by pay its own way is meant incremental cost of the required resources, then this principle has as its consequence that electricity tariffs leave income distribution unaltered. It is argued in this report that this is not essential in a government price policy for the energy sector.

2.13 Furthermore, in practice, the criterion for class of consumer is quite a different one from that needed for income distributional neutrality. Again the calculations for the allocation of costs implicit in the statement "pays its own way" involve the quite arbitrary application of accountants' rules for allocating historical costs 1/ of generation, transmission and distribution for capacity that jointly serves all customers. While such rules may be useful for some accounting purposes, they should not play a dominant role in the determination of price policies.

2.14 Electricity tariff structures, perhaps inadvertently, may provide incentives to users to waste electricity and occasionally even provide subsidies for waste. The incentive to waste is given in a pricing structure where some energy can be utilized by the consumer at zero marginal cost to him. This occurs most obviously when energy is not metered at all and electricity bills are based on some other criterion. In situations where the technical possibilities are small for increasing the amount of energy consumed and incremental energy is cheap, this may sometimes be an acceptable method of collecting revenue with low metering costs. Less obviously, zero marginal cost to consumers sometimes arises as a result of tariff constructions with "minimum consumption guarantees" that require each consumer to pay for a fixed quantity of energy per month, whether used or not. Identical in effect are those tariffs that specify a minimum monthly bill and thus provide a given number of kWh free of charge.

2.15 The minimum consumption guarantee was prior to July 1, 1969 a characteristic of WAPDA's private agricultural tubewell tariff, and the minimum bill is characteristic of the newly introduced tariff for small industry. 2/ This study strongly urges that such construction of electricity tariffs be avoided. The price signal to waste electricity up to a certain amount each month is improper.

2.16 An effective alternative is employed by WAPDA for industrial consumers outside the small category. The fixed charge is levied irrespective of the consumption of energy and has a minimum value governed by

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1/ Cost allocation or cost apportionment has a long history of application in electricity supply. The resulting allocations are widely but erroneously held to be valid bases for rate fixing. The nomenclature of cost allocation is firmly established by such usages as "consumer related", "energy related", and "demand related".

2/ Tariff B-1, effective July 1, 1969, gives an industrial consumer with 10 kW of connected load the first 226 kWh per month without extra charge. Again an industrial consumer with 50 kW connected load receives the first 1613 kWh per month free of charge.

the consumer's declared load. Energy is never at zero price, it has to be paid for in addition to the fixed charge. However, there are public relations difficulties with this alternative in that consumers who happen to use very few kWh may argue that they pay an excessive (average) price per kWh. Minimum consumption guarantees or minimum bills, although having precisely the same effect, are sometimes thought not to lead to this dispute. The serious defect of providing incentives to waste by expressing the minimum in a certain way should generally outweigh such considerations.

2.17 Subsidies for waste can arise when there are "breaks" in a tariff that lead to smaller total bills for larger total consumption. For example, a tariff that would charge a price of US$0.01 for consumers consuming 1,000 kWh per month or less and US$0.008 for those who consume more than 1,000 kWh per month in effect tells a consumer that he should consume 1,001 kWh rather than any quantity of energy between 801 kWh and 1,000 kWh. 1/ This anomaly is easily avoided by expressing the rates for incremental blocks of energy rather than for total amounts of energy.

2.18 Simplicity is often advocated as a desirable characteristic of electricity tariffs. Unfortunately, the proponents do not make clear the distinguishing features of simple rather than complex tariffs. It goes without saying that tariffs need to be written so that those who are responsible for applying them will know how to, and that costs of metering and administration which are linked with the concept of complexity require careful evaluation. Indeed major tariff revisions should be accompanied by an educational and training effort internal to the electricity supply undertaking that outlines the changes that have been made and their effects on record-keeping, meter-reading and billing practices. Similarly, consumers need to be informed as to how they are billed and what options are open to them for reducing their total electricity costs. Prices cannot signal costs if the messages cannot be readily received and interpreted by consumers or if proper bills cannot be prepared. It is not good practice, therefore, to publish a notification on July 15, 1969 of tariffs which go into effect July 1, 1969, as WAPDA did last year. WAPDA employees at sub-division offices and billing offices also apparently received no special briefings.

2.19 But if by simplicity in a tariff is meant a price, constant in time and space, and a price independent of other appropriate economic considerations, then simplicity as an end in itself should be firmly rejected as a criterion for price-making.

2.20 Closely associated with the criterion of simplicity is the criterion of stability. Unfortunately, it is true that electricity tariffs exist many years after all rationale for their introduction has disappeared.

1/ Scrutiny of WAPDA electricity tariffs did not uncover such foolish tariff construction; however, such tariff structures are common in transportation.

This, however, should not be viewed as a reason for planning an electricity tariff that is to have a long life. On the contrary, it should be a reason for planning price flexibility -- of planning institutionalized change. It is more desirable for electricity prices to reflect the relative scarcities and costs this year than to reflect those forecast for this year five years previously, those prevailing five years ago, or those now forecast to prevail five years in the future. An electricity supply undertaking should make widely known the plans for the future -- including the plans for the development of electricity prices; but today's prices should attempt to reflect today's resource costs. In an electric system heavily dependent on hydroelectric energy, it is conceivable that prices would be adjusted each year in response to the expected run-off into reservoirs. In any case, prices should be flexible, not stable. They should be responsive to changes in relative scarcities, and if these latter are changing in a rapidly developing electric power system, so should prices change.

2.21 However, it has to be recognized that the issuing of flexible and differentiated prices places greater burdens on the administrative machine than reliance upon stable, simple prices. There will be costs associated with the internal and external educational efforts to make the prices understood. Nevertheless the benefits of sensitive pricing in improving resource allocation seem likely to outweigh the costs of change and complexity in some cases, so that such changes should not be dismissed with the catchphrase "keep it simple: keep prices stable".

2.22 The stability discussed above and rejected as a criterion for electricity tariff policies is that of the rate structure and the prices applied to each component rate. However in another sense stability is a desirable characteristic. It would not be helpful to rational cost signaling if a consumer's electricity bills were to be volatile without economic reason. Pointless volatility and complexity in pricing can be criticized as impediments to effective economic signaling.

Two-part Tariffs

2.23 Electricity tariffs often consist of two parts. One part is a so-called fixed charge which may be determined according to various rules but is independent of the quantity of energy consumed. The other part depends on the energy consumed. The new private agricultural tubewell-tariff, for example, introduced by WAPDA in July 1969 and modified in February 1970, has a fixed charge per month determined by the kW of connected load1/ and an energy charge determined by the monthly kWh. 2/

1/ In effect, the horsepower rating of the electric motor driving the pump.

2/ It is important to distinguish between a two-part tariff in which the monthly bill is made up of the sum of the fixed charge and the energy charge, and a tariff like the WAPDA B-1 small-industry tariff where connected load is utilized to calculate minimum monthly charges, and the monthly bill is the fixed charge or the energy charge, whichever is greater. Such a tariff, which is not a two-part tariff as the term is used here, was earlier criticized for the encouragement it gives to waste.

2.24 In domestic tariffs, fixed charges are also sometimes determined on the basis of floor area, or connected load, or on the size of a fuse or of a circuit breaker, or on some other measure of "capacity" for consumption. However, two-part tariffs are not in use for residential customers of WAPDA. 1/

2.25 One of the most widely used methods for determining fixed charges of larger industrial consumers in Pakistan and elsewhere is to apply the readings of a quite complicated meter that determines the maximum demand of the consumer over a month or longer period. Such meters do not measure instantaneous surges, but rather record the highest 15-minute or 30-minute averages of demand 2/ over successive clock quarter or half hours.

2.26 The traditional rationalization for two-part tariffs is that the total costs of the electricity supplier also consist of two parts: the fixed costs which are independent of the amount of energy generated and the variable costs depending on amounts sold. The fixed charge in the tariff reflects the allocation of total fixed costs among those responsible for them, and the energy charge recaptures the variable costs.

1/ However, there is a minimum charge which, in effect, gives the residential customer the first 8 kWh per month without charge. There are no reliable data for estimating a frequency distribution of consumption by residential customers. But the proportion of consumers who would consume less than 8 kWh per month, if they could save on their bills by doing so, might be substantial. (A 60 watt lightbulb burned for 4-1/2 hours per day uses about 8 kWh per month.) In a sample of some Lahore customers in 1964-65 who were then billed mechanically using punched cards, over 40 percent of customers used less than 20 kWh per month; and this sample probably substantially under-represents the poorer consumers in the country.

2/ For a customer with a given time distribution of demand, the average over any 30 continuous minutes can never exceed the average over any 15-minute interval. From the theory of sampling it follows that generally the 15-minute average will exceed the 30-minute average just as the 1-minute average will exceed the 15-minute average. Systematic differences brought about by different integrating periods in these average readings could be compensated for by appropriate differences in the rates by which the averages are multiplied to obtain the fixed charges. The longer the integrating period, the more stability will be shown by the tariff both between months for a given consumer and between similar consumers. Such stability can be helpful in avoiding disputes. Note carefully, however, that the stability under discussion here (between-month variance and between-consumer variance) is quite different from the criticized concept of long-term overall stability of prices.

To overcome the criticism that there exists no unambiguous method of allocating fixed cost among those collectively responsible for it, the argument for the fixed charge is sometimes put slightly differently. A customer's peak load, it is said, represents the amount of capacity that must be reserved and set aside for his use and for which he should pay the fixed cost. Indeed, when maximum demand is metered, the reading of this meter measures the amount of capacity that must be set aside for him; and when it is not metered and fixed charge is based, say on connected load, this assessment still indicates the capacity needed for him.

2.27 Since, as is well known, individual maxima usually do not coincide with each other and with system peak, attempts have been made to estimate the likely contribution of an individual to system peak using the observed energy (E) and demand (D) in some more complex way than just pricing E and D separately. For example, one British industrial tariff runs:

Annual maximum demand tariff for consumers supplied at high voltage:

In any year	Pounds sterling, per kW per annum
For the first 200 kW	12.00
For the next 300 kW	11.50
In excess of 500 kW	11.25

and

	Pence per kWh*
For the first 2,400 kWh per kilowatt	0.960
For the next 2,400 kWh per kilowatt	0.860
For the next 1,200 kWh per kilowatt	0.785
For all kWh in excess of 6,000 kWh per kilowatt	0.625

* Old pence, i.e. 240 to one pound sterling. One penny is equivalent to one US cent.

The incremental energy prices are here seen to fall 1/ with increasing hours of use of maximum demand (increasing annual load factor) as follows:

1/ Tokyo Electric Power Co. uses a similar device. Discounts of up to 25% are given in accordance with the monthly hours of use. If the critical points used there are multiplied by 12, the Japanese critical annual hours are 4,200, 5,400 and 6,600. Evidently the thinking behind the two formulations was similar.

Hours of use of D, or E/D	0-2,400	2,400-4,800	4,800-6,000	Over 6,000
Incremental energy price, %	100	90	82	65

In addition, of course, the effective average price per kWh falls with increasing hours of use owing to the spreading of the demand charge over a larger number of kWh.

2.28 Behind this differential pricing is the concept that at 8,760 (24 x 365) annual hours of use, and to a lesser extent beyond 6,000 hours, the contribution of the individual maximum to system peak is assured -- the limiting case of the steady load of the individual. The concept was fully worked out by Constantine Bary 1/, but his statistical treatment of the relationships between individual maxima and group maximum (with groups of equal hours of use of maximum demand) can be seriously questioned.

2.29 Connected load appears to be an even less satisfactory index of a customer's demand at system peak; rarely, if ever, is a customer's demand at any time as great as the total rated capacity or connected load. Figure 2.1 shows that for a customer with a single machine -- a tubewell -- the rated capacity of the machine is not highly correlated with his own measured maximum demand. 2/

2.30 A two-part tariff basically is a device which permits the seller of electric energy to obtain for a given amount of energy sold a total revenue in excess of what he could obtain by charging a single price for energy alone. It is one of a number of techniques that economists call price discrimination which allows the average price of electricity to the consumer to exceed the marginal price. The consumer is encouraged to consume more electric energy than he would were the marginal price to be as high as the average price. It may encourage a higher intensity of utilization of the consumer's electrical machinery which in itself may or may not be desirable depending, among other things, on the price of incremental energy in relation to incremental costs of producing and delivering the energy. If the fixed charge depends on metered maximum demand, the tariff may also encourage excess investment by the consumer, allowing him to stagger the utilization of his machinery to increase his electricity load factor and hence to obtain the lower price. A two-part tariff, moreover, gives the lowest average cost of electricity to customers whose intensity of utilization of electric capacity is greatest and who would otherwise, therefore, find socially-uneconomical self-generation of electricity that much more attractive. 3/

1/ See the so-called Bary curve in C.W. Bary, Operational Economics of Electric Utilities, Columbia University Press, 1964.

2/ Tariffs based on "connected load" are likely to encourage production and installation of nameplates understating the actual rated capacity. Fortunately the data presented in Figure 2.1 were gathered in 1965, long before tubewell tariffs were based on "Connected Load".

3/ Electricity generation is subject to scale economies. Furthermore, the non-coincidence of different consumers' peak demands makes centralized generation usually more economical.

2.31 An important incentive provided by two-part tariffs based on metered maximum demand is the smoothing of consumption over the billing period, usually a month. Infrequently occurring peaks in demand during the period are penalized. The hypothetical consumer who consumes energy at an absolutely constant rate over the period (a load factor of 100%) pays less for the energy than one who consumes the same energy with any other time-profile. This incentive for smoothing is often considered a significant and desirable feature of the metered maximum demand tariff because, in a wholly thermal electric system with constant prices for inputs, the lowest cost of generating a given amount of energy occurs when the rate of generation is constant. This occurs not only because under these conditions the electricity supplier's capital equipment is utilized most intensively, but also because total fuel requirements for the delivered energy will be minimal. 1/ However, the technique of encouraging each customer to smooth his offtake is only one of various possible ways of planning for a smoother system load curve, and perhaps it is relatively ineffective and economically inefficient as well. Clearly another way is to encourage peak consumption for some consumers when the consumption of others is at a trough. Such methods differ greatly in concept from smoothing.

2.32 In a mixed hydro-thermal system, particularly WAPDA with Mangla and later Tarbela dams, in which the availability of hydroelectric power and energy is subject to sharp seasonal fluctuations because of hydrological and topographical conditions, on the one hand, and because of irrigation requirements, on the other, least-cost operations do not require long-period smoothing of energy consumption. On the contrary, least-cost operations generally require smooth supplementary thermal electric power production. That is, incentives should be presented to consumers to encourage them to reduce their demands when water heads and irrigation requirements are low and to increase their demands when heads and irrigation requirements are high. In this way, residual thermal electric generation is accomplished with maximum savings in fuel and capacity costs.

2.33 All this assumes inflexible irrigation requirements and constant prices for fuel inputs. If, however, the scarcity prices for fuel vary through time, then further incentives to apply are those which aim to conserve electricity consumption when fuel inputs are expensive, and which encourage consumption when fuel inputs are cheap. This becomes the condition for steady incremental cost operations of the thermal stations; i.e.,

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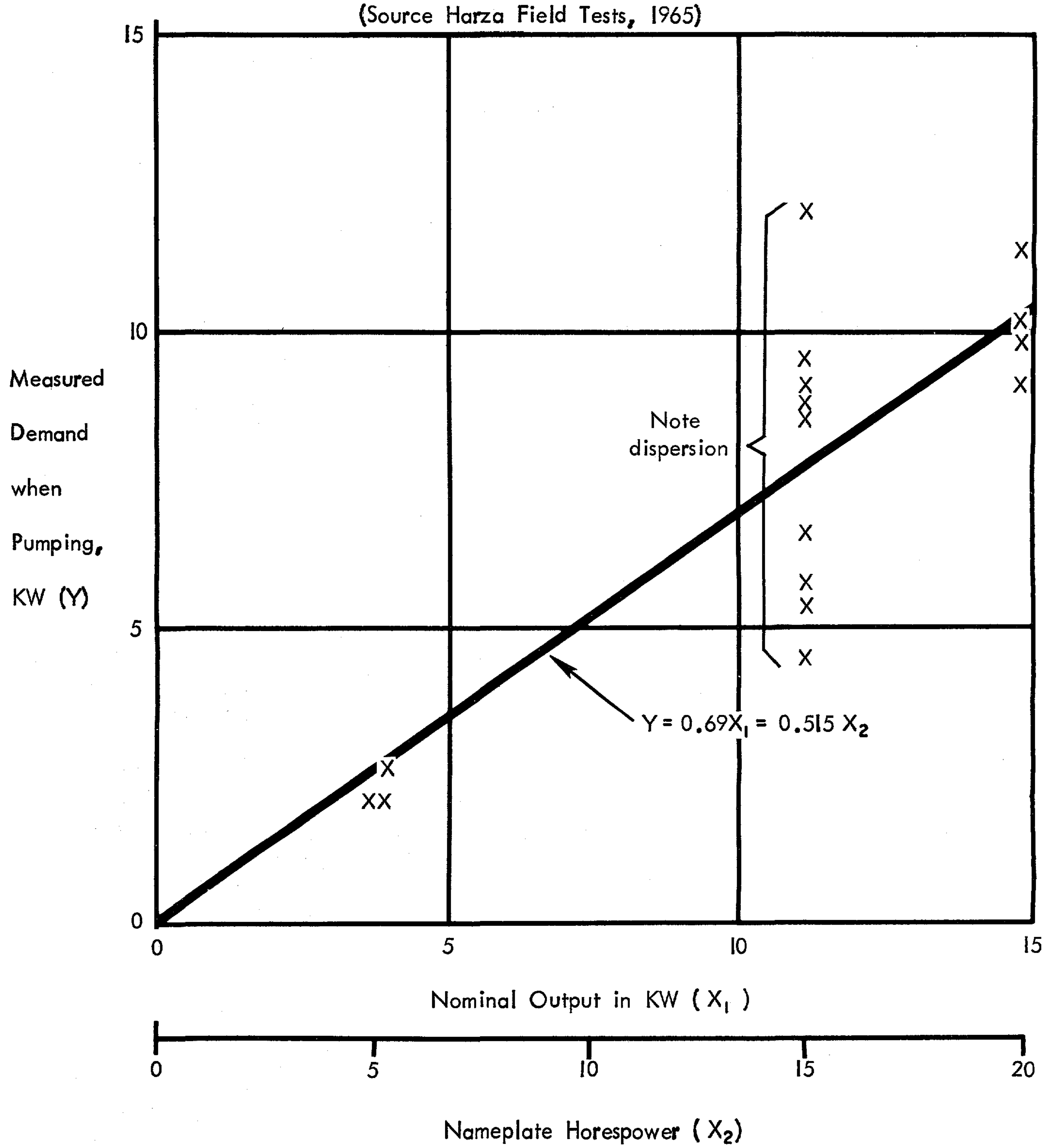
1/ Incremental cost (mainly incremental fuel costs) for such a system at any moment of time is a generally increasing function of the load. It is a proposition of relevant mathematical maximization theories (calculus, mathematical programming, etc.) that under such conditions the total costs for a given sum of energy outputs to be delivered over any specified period can be decreased by rescheduling production as long as the incremental cost at any one point in time differs from the incremental cost at any other point in time.

RELATIONSHIP BETWEEN MEASURED DEMAND AND NAMEPLATE HORSE-POWER FOR SOME PRIVATE TUBEWELLS

(Source Harza Field Tests, 1965)



least-cost production for the total energy used. Similarly, the time-schedule of demand for energy necessary for least-cost operations of the electric power system becomes more complex if rule curves for reservoir water releases are subject to economic choice. Shadow prices for water in relation to fuel prices as well as the shadow price of water as head (stock) in the reservoir become relevant. 1/

2.34 Two-part tariffs based on metered maximum demand from ordinary metering may also be used to encourage demand patterns other than smooth ones provided that the billing interval for the maximum demand charge is appropriately selected. Of course, maximum demand meters need to be read at least as often as it is desired to give consumers price signals to alter demands. In France, for example, increments to maximum metered demands registered during certain summer months in which there is added hydro capability on the supply system are charged at a small fraction per kW of demand of that charged in other months. The kWh charges also vary with the seasons, day of week and time of day. In the United Kingdom, similar devices have been used. In one case, the demand charge to be utilized for billing for an entire 12-month period is determined by the maximum registered during December, January or February (the period during which the system experiences maximum strain) or two-thirds of the maximum demand registered during any other month of the year. Another example follows where an intermediate price is applied for the transitional months to ensure that the incentives of lower prices are not overly effective when the system has only a slightly reduced demand (November and March):

Where the supply is metered at more than 650 Volts	For each kW of demand (monthly): December January & February	November & March	April to October inclusive
	Pounds, sterling		
First 200 kW	2.075	1.025	0.275
Next 300 kW	1.975	0.975	0.250
Additional kW	1.925	0.950	0.225

2.35 Such seasonal maximum demand tariffs, perhaps of the simple price-linked-to-month kind, seem worthy of serious consideration for early introduction by WAPDA. The required investment in additional metering is zero so that it is not necessary to guarantee beforehand a clearly favorable outcome to such pricing. There could be difficulties with missed meter readings, especially whenever the price increases,

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1/ Considerable theoretical research on such problems has been undertaken by economists and others interested in optimization theories.

though WAPDA's existing maximum demand tariffs are not particularly easy to apply. In fact an examination of 125 customers' monthly bills and meter readings for 1969-70 showed 60% in which the ratchet clause (see next paragraph) was apparently wrongly applied. This occurred mainly because the highest valid demand was not used for calculating the bill. Granted some improvement in the meter reading and billing of these important maximum demand consumers, there seems to be no solid reason why the expenditure on metering, meter reading, billing and collection should not result in a useful cost signal instead of the signal merely to smooth individual demand.

2.36 In the WAPDA system, the method for calculating electricity bills on the two-part maximum demand tariff (and, incidentally, also on all other tariffs now effective) involves rules without clear incentives for customers to adjust their demands to the expected temporal stresses on the system's capability. Instead they involve incentives for smoothing over intervals of arbitrary length. They have a structure based, so it seems, on the revenue requirements of the WAPDA system, on a notion of a "fair" average price for a hypothetical industrial consumer with an assumed average load factor, and on a fear that failure to have a 12-month or at least a 6-month ratchet (i.e. carryover period) would allow a consumer unfairly to get away with paying for "his share" of fixed costs. The WAPDA main grid tariffs in effect prior to mid-1969 used the higher of (P) the maximum demand established during a month or (Q) the maximum demand established in the preceding 11 months. 1/ If (P) was the higher one for a month, then this maximum would determine the rates applicable for each of the succeeding 11 months, unless during one of these later months, a still higher maximum demand were to be established. The mid-1969 revision of the tariff shortened the 11-month interval to a 6-month interval. However, a seasonal industry, that is, one which works for only part of the year, pays 25% extra for both fixed and energy charges, regardless of the time of year. The fixed charges are collected for a minimum of 6 months.

Voltage Price Differentials

2.37 Electricity tariffs should have price differentials depending on voltages at which the consumers take delivery. Prices independent of voltage encourage (industrial) consumers to take delivery at lower voltages and require the supplier to absorb capital costs of transformers and switchgear as well as the transformer losses. The tariffs should signal such cost differentials so that capital plans of consumers will tend toward appropriate economic choices as to voltage. Such calculations should be based on appropriate valuations of the resources including an appropriate shadow price for foreign exchange. Where the electricity supply organization is heavily burdened with solving distribution problems,

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1/ Unless the load "declared" by the consumer exceeds both of these numbers.

these prices could signal this scarcity of distribution capacity and encourage supply at higher voltages. The mid-1969 revision of WAPDA tariffs eliminated all the differentials between 33 kV, 66 kV and 132 kV for both bulk and industrial supply, whereas previously some differentials had existed.

Regional Price Differentials

2.38 Transmission and distribution require substantial capital outlays and also variable costs largely in the form of energy losses. Consumers with large loads and consuming large amounts of energy nearer to generating centers thus would require lower quantities of scarce resources for the same supply taken elsewhere. Electricity tariffs, particularly those applicable to large industrial consumers, should help signal to economic planners in the public and private sectors the cost disadvantages of consumption far away from the sources of supply. Prices that fail to convey these cost messages in effect give subsidies to locations remote from generating centers. 1/ If there is a social policy to give certain regions subsidies for industrialization, electricity tariffs seem to be an inefficient vehicle for providing them. Absence of regional price differentials also tends to distort the choices between competing energy sources. At the present time, WAPDA's tariffs include no regional differentials, except for an especially low tubewell tariff in the Northwest Frontier Province.

Price Sensitivity of Demands

2.39 Implicit in discussions of the rationing function of prices is the view that price differentials sufficiently large and widely publicized to consumers and potential consumers will generally cause alterations in use of resources and specifically cause alterations in the shape of system load curves. This does not mean that every consumer will respond to the price incentives offered to him in all electricity uses, only that some consumers will respond to them in some uses. Certain uses of electricity are more likely to respond to price incentives than others. Some responses are possible without alterations in capital expenditure plans of customers, requiring mainly rearrangement or reorganization of plant and work schedules, and are likely to occur more quickly in response to tariff incentives. These are the short-run effects.

2.40 Other responses require new or different machinery or appliances so as to take advantage of electricity price differentials. These are likely to take longer to become effective and are called long-run effects.

1/ Distribution costs, however, generally are lower in areas with higher densities of consumers.

But quite generally, optimizing behaviour by electricity purchasers will generate a program of current input utilization and of capital expenditures which would be sensitive to electricity tariffs as well as to other input prices. Such programs generate the demand for electricity provided that customers have, in fact, incentives to optimize. Thus, existing electricity prices have their effects not merely on how electricity is utilized but also how other resources, complements or substitutes, are utilized.

2.41 In looking more closely at how electricity tariffs influence demand for electricity, it is assumed as a working hypothesis that the total demand for electric energy, say the number of kWh consumed per annum, is not changed as a result of changes in electricity tariff structures and in other fuel price structures. This is not to say that electric energy consumption is independent of electricity tariffs. On the contrary, the argument is that the price changes to be considered in this study have this restriction imposed on them. From the extensions of the theory of derived demand, one can deduce that the price elasticity of demand for electric energy sold during a specified interval or during a set of intervals is likely to be <u>lower</u>:

a. if the products embodying electricity and produced in one interval cannot be readily substituted technically for products produced in another interval;

b. if the products embodying electricity are subject to high storage cost;

c. if cost of electricity is a small proportion of variable cost of the products embodying the electric energy;

d. if capital goods related to electricity utilization in the consuming industries have long gestation periods;

e. if electricity consumers have low excess capacity on round-the-clock operations;

f. if political and sociological reasons prevent multiple shift operations in electricity consuming industries;

g. if price time-profiles of complementary inputs to electricity are negatively correlated with those of electricity prices;

h. if electricity consumers own no standby generation capacity.

These propositions are corollaries of the economic theory of derived demand and also are empirical conclusions of the field studies, including interviews of electricity consumers in West Pakistan.

2.42 There does not seem to be a simple relationship between idle capacity of electricity consuming equipment and idle capacity of electricity producing machinery. One might suppose that a rationing scheme that smooths the peaks and valleys in electricity consumption in the daily cycle, for example, encourages idle capacity among electricity consumers at the same time that idle capacity of the electricity producer is reduced. Instead of the electricity producer having idle generating capacity "waiting" for the consumer, the consumer has idle capital goods "waiting" for electricity. There may be some truth to such trade-offs. Discussions with management of a cement mill, for example, revealed that in this continuous process, high-load factor operation, additional capital expenditures would be necessary for a possible plant expansion that would be able to take advantage of reduced night-time electricity prices. Discussions with management in an engineering works, on the other hand, revealed that existing idle capacity in the plant was allocated between night and day so as to take advantage of lower kWh prices for electricity that the existing two-part tariff offers for high (average) load factor operations.

2.43 Efforts to shift electricity consumption through time so as to reduce costs of the electricity supply undertaking may also lead to added social costs for other inputs used by customers. For example, factory labor at night or seasonal factory labor may be less efficient, and it may also be less desirable from the point of view of the workers. To the extent that such social cost differences are reflected in price differences (e.g., wage rates) they will influence electricity consumers appropriately in making their intertemporal production decisions. If they are not reflected in price differentials of such other factors, then electricity price differentials could encourage socially inefficient temporal shifts in electricity consumption based essentially on faulty cost signals for these other resources. There is no presumption that faulty cost signals for the resources elsewhere in the economy will bias, in the direction of higher social cost, the consumer's intertemporal choices based on cost-related price messages for electricity. At the same time that, say, absence of wage rate differentials fails to signal the undesirability of nightwork, the absence of differentials in the price of natural gas fails to signal the desirability of night work. The failure of many other prices to give proper signals is not an argument in favor of having electricity prices give improper signals. Indeed, the argument in favor of having proper cost messages conveyed by electricity price differentials is also the argument in favor of price differentials elsewhere in the economy transmitting these messages.

2.44 This discussion should help clarify that the proper objective of a price policy for the energy sector or the electricity undertaking is not the minimization of the cost of producing electricity. An ideal load curve is not one which fully utilizes all of the available generating capacity all of the time. Rather, it is one which rations to the highest priority uses the available capacity and associated fuel. It is one which has capacity idle only during those hours where the value of the electric energy in highest priority uses does not cover the cost of the fuel. And it is one where the last increment of capacity is added only if the capital together with associated fuel produces electric energy over its lifetime which in its highest priority uses is more valuable than the alternative uses to which the capital and fuel can be put. Characterizing the problem in this way is to state it, not to solve it.

2.45 The theory of first-best welfare economics demonstrates that if prices everywhere in the economy and for all points in time are exactly equal to marginal cost then and there, socially efficient allocation of resources will result in the sense that no one person in the economy could be made better off by a reallocation of resources without at least some one other person having his economic position worsened. Thus, if resources elsewhere in the economy are "properly" valued, the reallocation of resources that would be the result of the proper electricity tariffs would be improvements in economic efficiency in this sense of efficiency. Unfortunately for the pricing problems at hand, this proposition cannot be directly applied. Prices elsewhere in the economy do not have the properties postulated. Furthermore, the theorem assumes that there exist no direct interactions of external economies and diseconomies and of public goods, that the problems associated with taxation and equitable income distribution for the society can be solved without introduction of taxes that destroy the equality of marginal resource cost and price, and that the problem of the appropriate level of saving and risk-bearing can be neglected. Nevertheless, it is propositions like these, together with demonstrations that prices set proportional to marginal cost will increase economic efficiency provided that certain of the economic interdependencies can be neglected, which form the basis for the practical pricing proposals of this study.

2.46 It is appropriate to conclude this chapter with a quotation of a paragraph from the June 1970 Draft of the Fourth Five-Year Plan for the Power Sector written in the Power Development Section of the Planning Commission of the Government of Pakistan. 1/

> Peak lopping, i.e., maximizing energy at the expense of demand capacity merits serious consideration during the Fourth Plan particularly in the northern region. This would enable postponing investment in additional units at Gudu and possibly the later units at Tarbela. Peak lopping could be achieved by encouraging energy usage during off-peak load hours through tariff incentives and/or by forced restricted hours of supply by installation of timeswitches at the consumers' premises. The additional cost involved in double metering and timeswitches will be negligible in comparison to capital cost of additonal generating equipment.

1/ A lengthier excerpt is given in Annex 3.

3. OBSTACLES TO REVENUE ASSESSMENT AND COLLECTION

3.01 During negotiations for a development credit of US$23 million to augment the substation capacity of the WAPDA system, see Report PU-36a July 1970, agreement was reached on a program for reducing losses. That report in paragraph 3.03 describes the steady increase in losses and energy unaccounted for from 24% of net generation in 1965/66 to 32% in 1968/69. The agreement reached was that WAPDA would undertake a comprehensive effort, administered by a specific group, to identify and reduce system losses, and would report to the Association periodically on progress in this matter.

3.02 The interest of the consultants was not in losses of energy as such but in the implications of extensive pilferage as casting doubt on the integrity of the price mechanism. Arguments as to price elasticity and as to the value of differential pricing of electricity by time of day or season of the year seem to make little sense when the consumer readily has the option of paying zero price. Again the extension of metering devices to time-switches (and so on) and circuits between the component devices enhance, rather than mitigate, the possibilities of tampering.

3.03 While the consultants were in Pakistan they learned that for 1969/70 the losses were claimed to be reduced by 2 percentage points instead of following the usual upward trend.

3.04 The use of the statistic "proportion lost of net generation" as used in the Bank's report is greatly preferred to WAPDA's use of "proportion lost of total generated" in that the latter, inflated figure fails to isolate the areas of responsibility. Another statistic which should be made available in the near future is the "proportion loss of energy received at 11 kV", bearing in mind that WAPDA have already committed themselves to the installation of energy meters on all 11 kV feeders. In any case a main input-to-bars meter will often already be found on the 11 kV transformer output. Energy input at 11 kV for sale can be readily calculated by summating the thousand or so inputs. This recommended statistic would eliminate the losses on the transmission system which are characteristic of hydro generation remote from load centers. In consequence, with this preferred statistic the effectiveness, or otherwise, of the steps being taken to reduce power pilferage would become more evident.

3.05 While it is convenient to have these statistics, to act as a performance yardstick in the task of reducing pilferage, the more general problem of revenue leakage cannot be expressed in this way. Not every action to avoid paying the correct electricity dues can be reflected in energy statistics. For example, maximum demands can be under-reported for industrial consumers, late-payment penalties can be waived, and consumers can be put on to tariffs more favorable than their entitlements. None of these actions will be reflected in energy statistics, though some of them could, at least in principle, be detected by other statistics.

3.06 It is therefore recommended that WAPDA report the statistic "proportion lost of energy received at 11 kV" to focus attention on the effectiveness of energy-pilferage programs and that the negotiated review of progress of loss reduction be extended to the wider issues of revenue leakage.

3.07 In presenting these statistics some allowance should be made for the apparent loss caused by non-coincidence of the generating year and the consumers' billing year. Usually, owing to cyclic meter reading, the year of account for residential consumers is displaced, i.e. lagged, by at least half a reading cycle. Provided consumption is growing, this displacement gives rise to an apparent loss of energy. It should equally be noted that the statistic "units sold" is sensitive to the precise timing of the end-of-year accountancy guillotine.

3.08 According to a thoughtful analysis by G.C. Hufbauer, consultant to the West Pakistan Government, dated July 1969, of "Electric Power Losses in the WAPDA System" the proportion of energy pilfered in 1968/69 was about 13.4% of total generation. This adjusts to 13.8% of net generation or, say, 14 percentage points out of the 32 quoted in paragraph 3.01.

3.09 He rightly draws attention to the enormity of the revenue leakage. The estimated 585 million kWh pilfered (the precision is certainly spurious) in 1968/69 he prices at the average of 11.3 paisa per kWh. However much of the revenue lost is likely to stem from tubewells at 6 paisa per kWh (using current prices) and larger industrial consumers at 7 to 8 paisa per kWh. To understate the lost revenue, it is likely to be running at a level of 585 X 7 X 104 rupees or, say, PRs 40 million (US$8.4 million). This is an estimate of the revenue leakage flowing only from the pilferage of energy and not from other causes.

3.10 This sum of money, or a larger sum from all causes, can be interpreted as available in part to purchase considerable resources of engineering and other skills. The question then arises as to whether the opposing resources provided by WAPDA and the legal system are sufficient to reduce pilferage quickly to an insignificant amount and to hold it at that level.

3.11 On December 29, 1969 the Managing Director (Power) issued a directive to the four regional Chief Engineers emphasizing the importance of the so-called action plan "to raise overall efficiency, to reduce losses and pilferage and to increase revenue from the sale of power". He drew attention to four important points:

a. Reduction of technical losses on the distribution system.
b. Reduction of losses due to stealing of energy.
c. Recovery of arrears of revenue.
d. Disposal of surplus stores.

3.12 It is interesting to note that he did not refer to the more general problem of loss of revenue, excepting that he raised an allied issue, namely arrears of revenue. These are described as "huge" with Government agencies as important offenders. The impression was gained by the consultants that the usual threat of disconnection had little effect, perhaps because the threat was judged to be hollow. Again it was widely reported that WAPDA have insufficient support from the Electricity Act and from legal processes for both the punishment of energy thieves and the recovery of arrears.

3.13 WAPDA say they are examining a case for the amendment of the Electricity Act and, as a short-term measure, that they intend to apply for a Martial Law Regulation. Both these measures are in relation to the theft of energy.

3.14 Some of the arrears of revenue arise where the account for electricity is disputed and the courts have granted a stay of execution. With the very large industrial consumers, the possibilities of dispute are enhanced by the inadequacy of the existing metering on technical grounds and of the meter reading and billing practices.

3.15 In one case examined in detail, the consumer had a monthly consumption of 2.5 to 5.0 million kWh and a maximum demand of about 10 MVA. The account had been in dispute for five years. The supply was by twin parallel feeders each with its own energy meter and maximum demand indicator. Both the energy advances and the monthly maximum demands were summed to give the consumer's energy and demand for billing purposes. Normally the supply divides equally between the two feeders and meters but whenever a feeder breakdown occurs, one of the maximum demands is more or less doubled. In consequence the consumer's bill is frequently inflated by the chargeable maximum demand jumping from, say, 5+5 = 10 to 10+5 = 15 MW, i.e. an over-charge of PRs 70,000 (about US$15,000).

3.16 Either a single meter should have been installed in the busbar or the two meters should have been summated automatically, e.g. by an impulse summator. Another less conspicuous metering defect was that the maximum demand was being measured on a quarter-hourly basis instead of the tariff basis of half-hourly. Out of 34 monthly readings examined only in 13 cases did the energy and demand split equally over the twin meters so that no dispute could arise (apart from the lesser issue of 1/4 hour v. 1/2 hour integration).

3.17 This example is noteworthy in that:

a. the dispute was allowed to drag on indefinitely
b. no metering specialist was available to advise on the technical solutions, and
c. sometimes the consumer may be overcharged instead of being undercharged.

3.18 What seems to be a fairly effective method of reducing pilferage, at least in the short-term, is the installation of steel boxes in which the meter is enclosed. The steel boxes are welded shut. Figure 3.1 shows such a box on the right, together with an alternative wooden one on the left which has a secret lock and is nailed shut. The action plan mentions "a continuous program... on the industrial and agricultural connections" and it was said that several thousand such boxes had been installed. Table 3.1 shows the detailed progress in one of four regions.

TABLE 3.1

INSTALLATION OF ANTI-THEFT BOXES IN EAST REGION AS AT JANUARY 1970

Area	Steel Boxes	Wooden	Total
1st Lahore Circle	157	521	678
2nd Lahore Circle	212	518	730
Gujranwala Circle	307	1,607	1,914
East Region	676	2,646	3,322

Note: About 20% of the total boxes are of steel. Wooden boxes are used for the smaller consumer, especially industrial consumers of up to 15 horsepower.

3.19 Such boxes cannot be used with high voltage consumers effectively to enclose the "meter" since the metering connections necessarily extend to the potential and current transformers. The most promising application is to 400 volt industrial consumers of up to 70 kW installed load and to private tubewells (Tariffs B 1 and D). Neither can welded-shut boxes as now designed be used with industrial consumers above 70 kW since access has to be gained to the maximum demand indicator to reset it to zero each month. A remote demand-indicator control could however be added.

3.20 For private tubewells the boxes can be mounted externally to the pumphouse, see Figure 3.2, to make any act of interference less private. This external metering also avoids the "no-access to read meter" problem which, with private tubewells, leads to arrears of revenue. Here it is interesting to note that the standard American outdoor meter has a metal base, an undrillable hard-glass cover and is conspicuously mounted outdoors.

3.21 While meter boxes offer the most promising solution to energy pilferage in many cases, it is far from certain that there is any single long-term solution in terms of hardware. Table 3.2 which follows enumerates some seventeen distinct methods of defrauding WAPDA. Every "solution" adopted by WAPDA is likely to be countered by the application of an alternative method or perhaps some newly-invented variant.

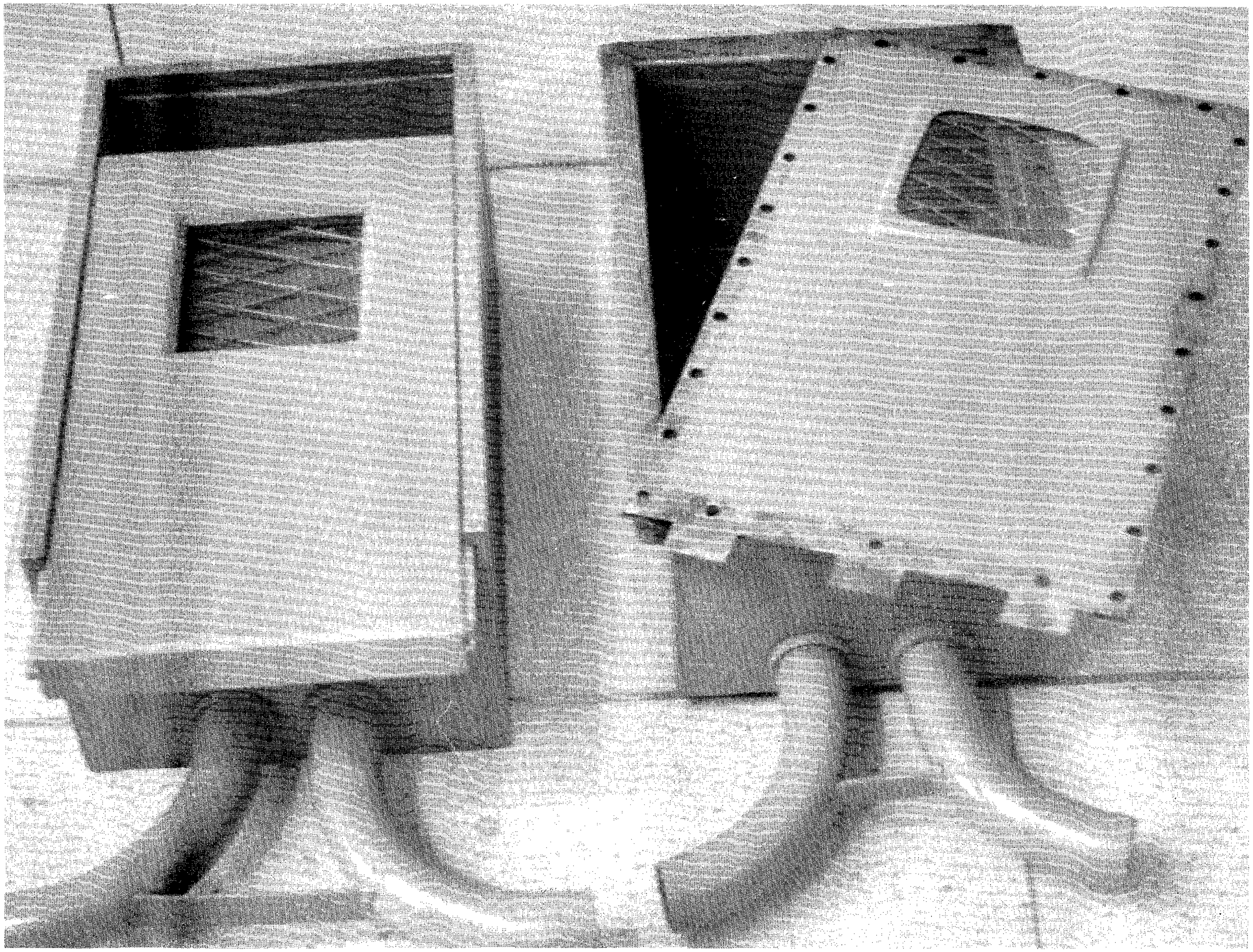

Figure 3.1 - On the left is a wooden anti-pilferage meter box with secret lock and on the right is a steel box which is welded shut through the holes in the flange.

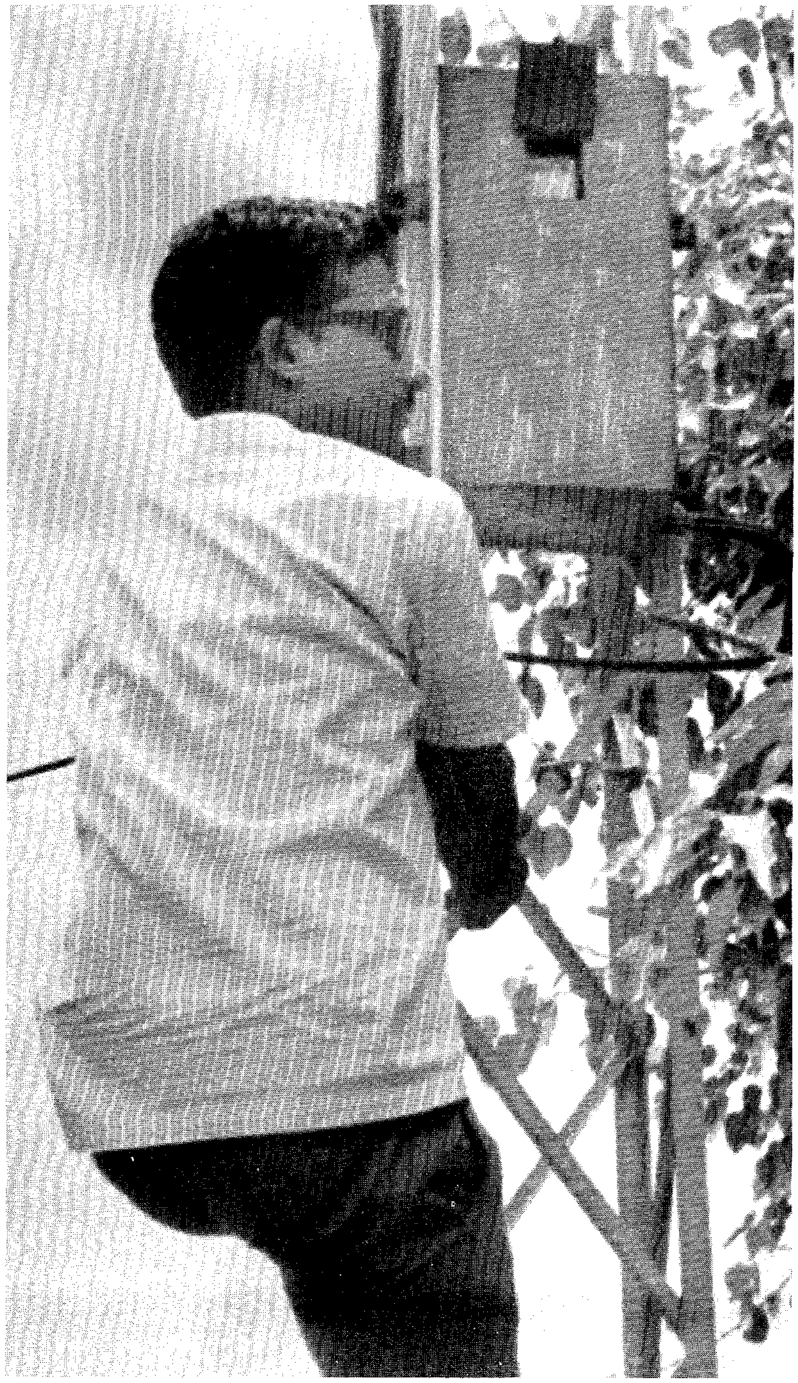

Figure 3.2 - This shows a steel box enclosing a meter serving a private tubewell. To read the meter (or to tamper with the box) it is necessary to climb the service pole.

TABLE 3.2

ENUMERATION OF METHODS AVAILABLE TO DILUTE REVENUE OR PILFER ENERGY

A. Without loss of energy

(1) Meter read but bill not delivered owing to inadequate records as to name, address or rate.

(2) Meter read and account rendered but never collected or payment delayed indefinitely.

(3) Meter read, account rendered and paid but on a cheaper rate than entitlement or with late payment or other supplementary payments omitted.

(4) Maximum demand understated by meter reader who cannot effectively be challenged once the demand pointer has been reset to zero as an obligatory part of the monthly reading procedure.

B. With total loss of energy

(1) Consumer connected but part of the paper work mislaid so that the meter is never read.

(2) Meter by-passed with a jumper lead.

(3) Illegal connection made to the supply mains without applying for a meter.

(4) Meter stopped by braking disc through pinhole in case using a needle or bristle as a brake. See Figure 3.3.

(5) Meter stopped (may creep slightly) by disconnecting the voltage coil (or coils) at the test link on the terminal block.

(6) Metering of high-voltage supplies stopped by removing fuses or links from the metering circuit wiring from the potential or current transformers. More subtly, the wiring can be flexed until the conductors fracture within the intact insulation or pinch screws can be loosened. These methods cannot be used with low-voltage supplies (whole-current metering) where the faulty connections would equally interfere with the consumer's electricity supply.

C. With partial loss of energy

(1) Methods B2, 4, 5 and 6 applied intermittently as would normally be the case.

(2) Meter direction reversed to destroy record of previous consumption often combined with missed meter readings to make the reversal worthwhile. Seems to be an organized practice.

(3) Register turned back either by opening meter and replacing seals or by using a steel "picklock" through a pinhole drilled in the case; see Figure 3.4. Confusingly this practice is called "reversing the meter" as is the previous method.

(4) Three-phase three-wire (2-element) meter as used for high-voltage supplies slowed down to about half speed by reversing one of the meter elements, i.e. transposing a few wires at the meter.

(5) Three-phase four-wire (3-element) meter as used for 400 V industrial consumers and tubewells slowed down to about one-third speed by reversing one element, i.e. transposing connections at the meter.

(6) For important supplies, the meter reading has to be multiplied by a constant such as "times 100". A wrong multiplier can be entered in the billing records, e.g. "times 50".

(7) For a given meter manufacturer, the dial plates carrying the register are usually interchangeable among meters of different current ratings. The gear ratios differ so that some meters can be arranged permanently to register, say, half the true consumption.

(8) Meter readings avoided for some time, followed by smashing the meter and refusing to pay an estimated account. Such violent practices, without subtlety, are more likely in rural areas.

3.22 WAPDA have for some time ordered all new meters with reverse-running detents to prevent Method C2 (meter reversal) being used to destroy backlogs of consumption. These devices add PRs 4 to the price of a single-phase meter and PRs 10 to a three-phase one. Unfortunately the detents facilitate a variant of Method B4 (meter braking) in that whereas the meter could previously be made to run backwards it can now be made to remain stationary forever, held by the detent. The advantage gained by the use of these devices is therefore seriously open to question once the pilferers have adapted to the new situation.

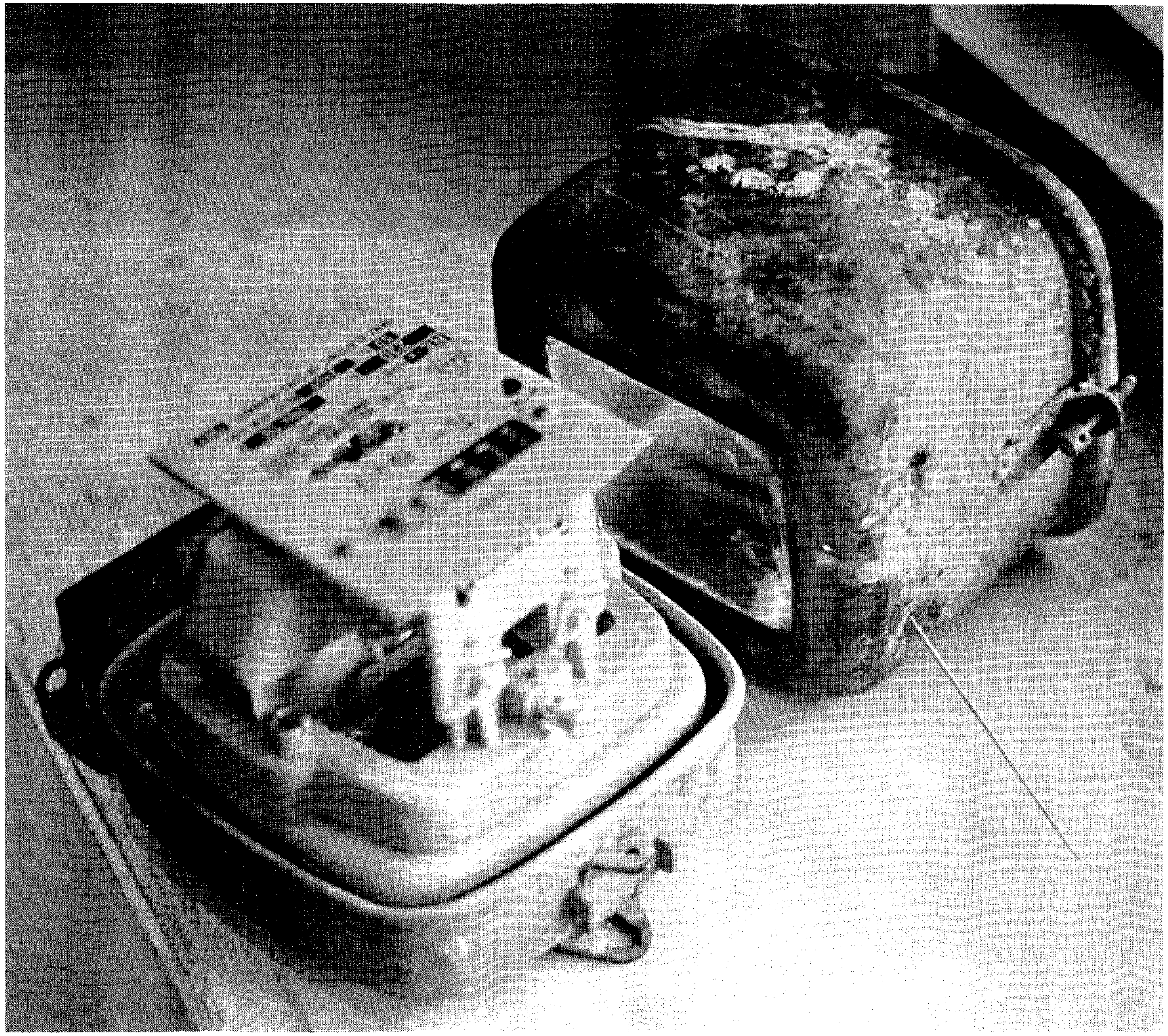

Figure 3.3 - The steel case of this single-phase meter has been pierced off-centre so that a needle may be inserted to brake the meter disc.

Figure 3.4 - The steel case of this single-phase meter has been pierced centrally near the front of the cover. With a bent pin the cyclometer register can be turned back. Whether this will work with every design of cyclometer register is not known.

3.23 Existing billing practice (pre-computer) is to bill negative advances as if they were positive. In consequence the consumer gains with a reversed meter only at the first reading after the act of reversal. Subsequently he gains no advantage until the meter is perhaps once more reversed, this time to run forwards. However, residential meters seem often to run backwards.

3.24 On one ledger page of 40 consumers' meter readings at a sub-divisional office about 20% had negative advances and the general proportion seemed to be 10% or so. However some of these could have been caused by the meter reader guessing the reading without bothering to visit the consumer -- this practice can easily lead to a subsequent negative advance on actual reading. Under the latter circumstances the consumer is likely to be overcharged as follows:

Meter read on three occasions			Central reading guessed too high	
Month 1	1,000		1,000	
		200		400
Month 2	1,200		1,400	
		100		(-100)*
Month 3	1,300		1,300	
		———		———
Billed		300		500
		(True)		(False)

*Billed as if positive

It was observed that the consumer could expect some difficulty in getting the overcharge rectified.

3.25 A determined effort is now being made to transfer 208,000 monthly bills in Lahore from conventional punched card machinery to a computer. Difficulties are being experienced and some of these throw light on billing and revenue collection problems in general on the presumption that practices outside Lahore are not radically different. Until recently the meter reading books were not arranged as convenient "walks" but were in the order of application for supply. This encouraged guessed readings though, even with the improved order of visits, it was thought that guessed readings were commonplace.

3.26 The computer program has to handle sensibly the legitimate case of the meter register going through the nines. For example with an advance of 30 kWh:

Not through nines	Steps	Through nines
0,800	Latest reading	0,010
0,770	Previous reading	9,980
(1)0,800	Add 10,000	(1)0,010
0,770	Subtract previous	9,980
10,030	Difference	0,030
0,030	Suppress 5th digit	0,030

However with guessed readings or with reverse running meters the computer will focus attention on the inadequacies of the procedures as follows:

Negative advance	Steps
0,740	Latest reading
0,770	Previous reading
(1)0,740	Add 10,000
0,770	Subtract previous
9,970	Difference
9,970	Suppress 5th digit

This can be prevented by programming the computer to reject unusually large bills but it demonstrates that the marriage of a strictly logical computer and a dysfunctional metering/reading system is likely to be eventful.

3.27 The above views on computerized billing accord with those expressed by Lord Hinton, November 1969, who recommended a cautious approach in the light of WAPDA's experience and local knowledge.

3.28 However the examination of the reading and billing procedures by those responsible for implementing computerized billing is already helpfully illuminating problem areas though the computer team will need substantial support from the organization to rectify these problems. For example, in an examination of 24,000 consumers, it was found that some 10% were on the wrong rate for billing purposes if the basic record, i.e. the original registration, is believed. Of these at least 70% were in the direction of cheaper rates (see Table 3.2, Method A-3).

3.29 Also it was reported that there is some three to six months' delay in the paperwork of the connection procedure which causes the bills to be issued in the first place. Furthermore many accounts were brought to light with account reference numbers, perhaps a name, but without a traceable address (Method A-1).

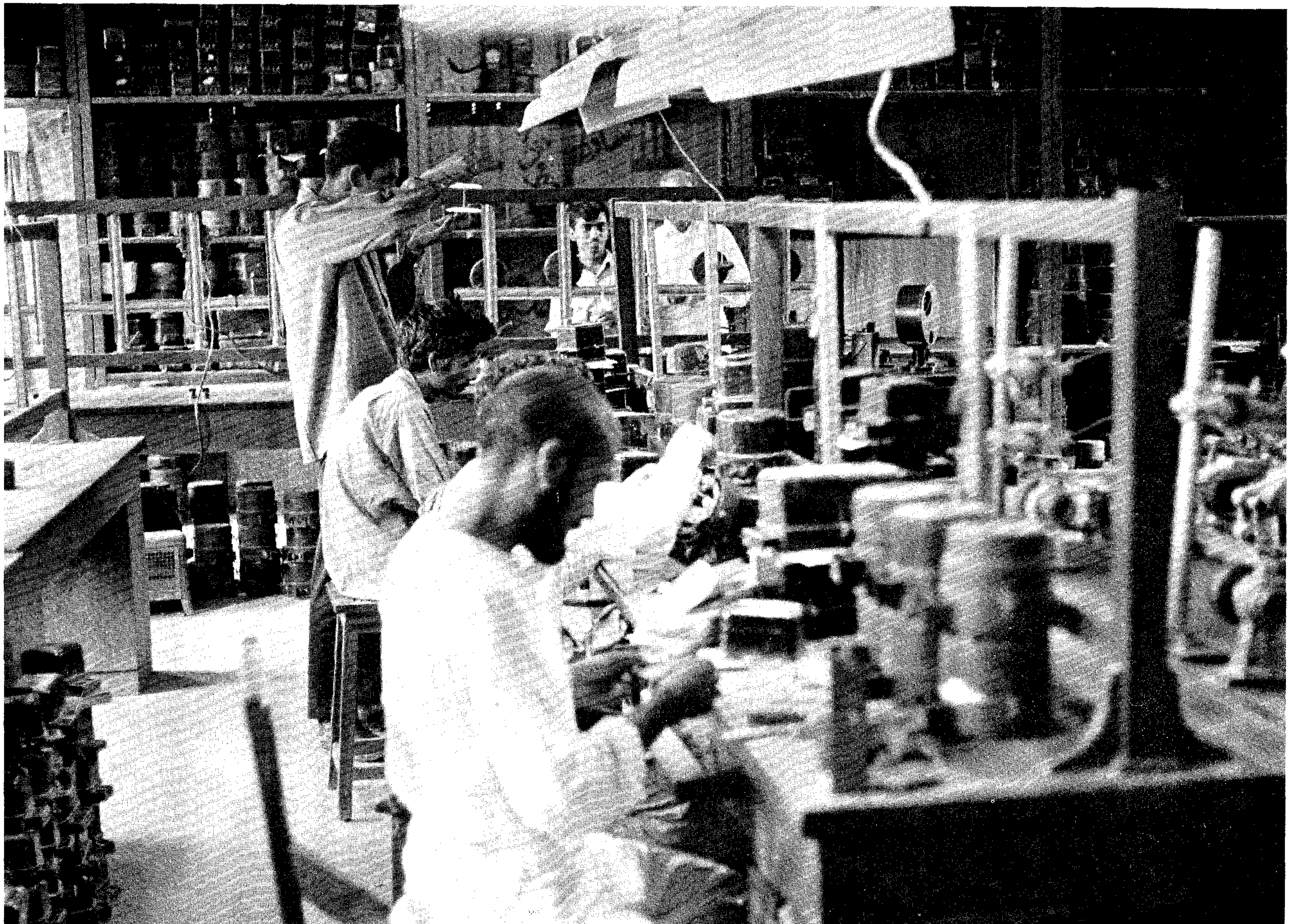

Figure 3.5 - General view of a meter repair shop at Lahore.

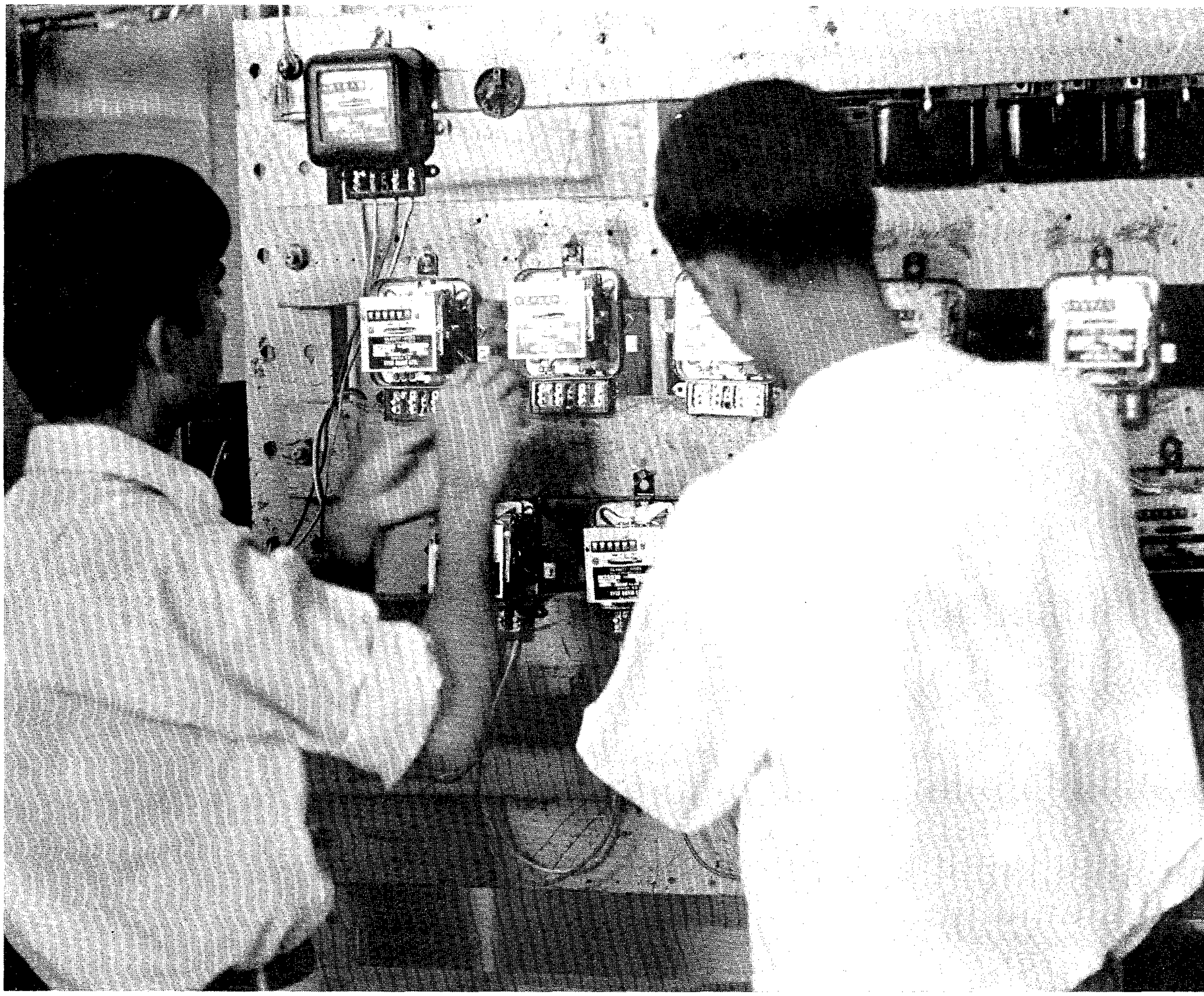

Figure 3.6 - New single-phase meters on acceptance test. The meter at the top is the sub-standard of known and stable performance.

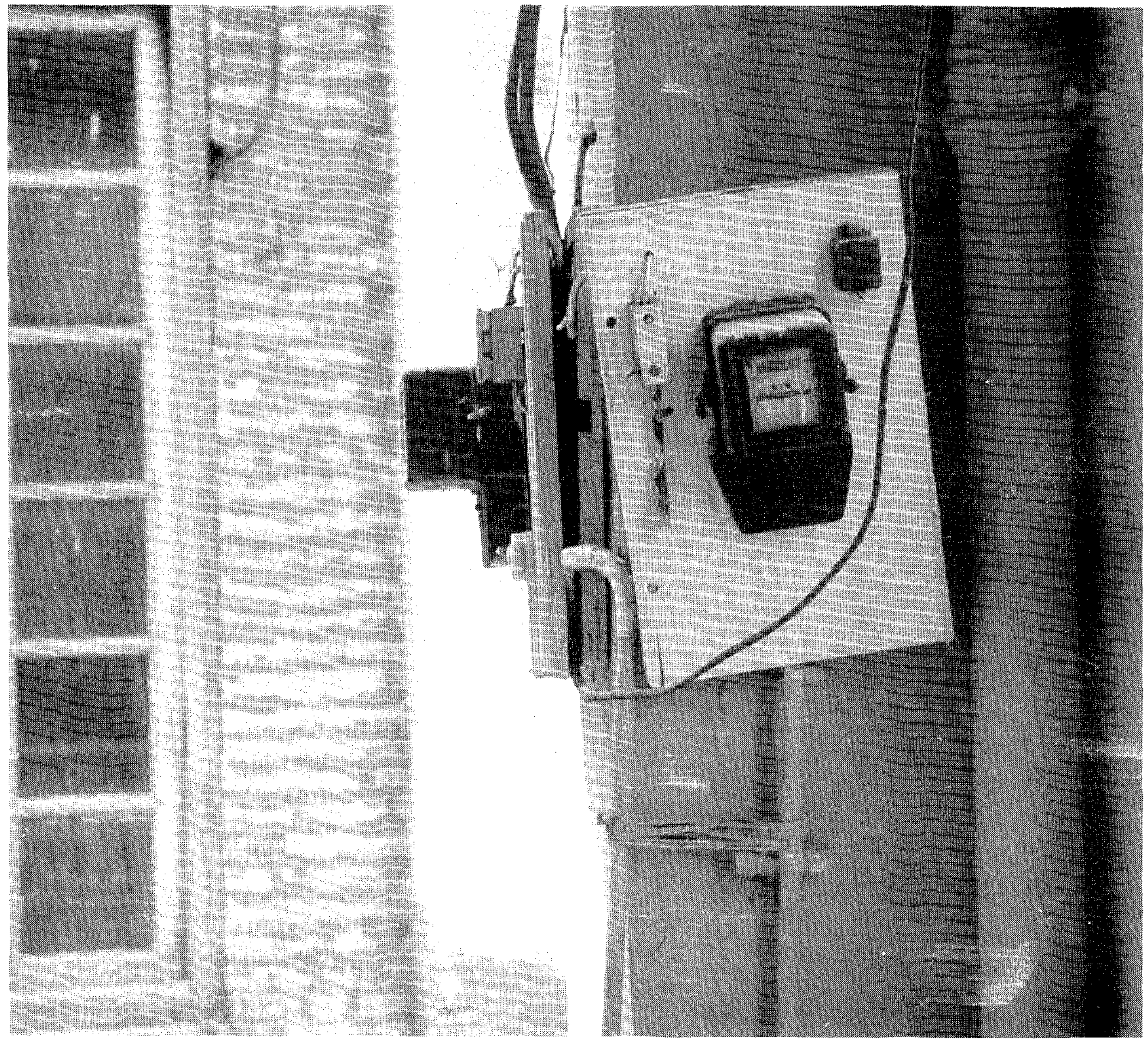

Figure 3.7 - Meters are not always mounted vertically.

3.30 While some of these "errors" could be dismissed as delays and muddle inseparable from the reading and billing of a million consumers using many inexperienced workers, the consultants did not feel that the problems were being accurately reported to management, nor that the latter grasped the need for truthful, frank reporting followed by performed remedial action stemming from the allocation of sufficient resources of men, organizational skills, budgets, transport, accommodation and rewards to constructive staff. Of course the detection of pilferage and associated fraudulent activities is likely to involve unpleasantness with both consumers and with WAPDA employees. Recently, "the detection squads were also able to haul up 105 employees of the Department who were conniving with the consumers in stealing power" (WAPDA Weekly 1st July 1970).

3.31 The primary responsibility for detection lies with the local offices in charge of maintenance of the local distribution system. They have many other duties, run the grave risk of being corrupted and are subject to other local pressures, including threats. The second line of defense is formed by four regional detection squads under each Regional Chief Engineer. One region had some fifteen staff in the squad, though they also had other duties. Broadly, perhaps 50 full-time detection staff in WAPDA are attempting to remedy a long-standing problem which embraces a million consumers.

3.32 Centrally there was no single full-time (at this task) senior manager responsible for detection, the reduction of pilferage and improvements in revenue collection practices. With some, say, PRs 40 million at stake (paragraph 3.09) a full-time officer, without other duties, would seem to be fully justified. Paragraph 3.03 of Report PU-36a says that loss reduction is to be "administered by a specific group".

3.33 Detection staff mentioned threatening letters, and complaints about their conduct by disgruntled consumers. In contrast they found no rewards offered for succesful detection and needed encouragement to carry out their distasteful tasks. Practical points needing attention were a shortage of three-phase meters, shortage of transport and the inadequacies of the meter testing facilities.

3.34 The consultant engineer thought that the meter testing and repair facilities could indeed be improved; see Figures 3.5 and 3.6. Again there seemed to be a need for central direction by a manager with only one set of responsibilities, fully trained in meter engineering. Some of the loss of power probably arises from poor metering practices. For example, see Figure 3.7, meters were sometimes mounted out of the vertical. This practice slows down the meter by several per cent especially at light load.

4. THE DEMAND FOR ELECTRICITY

4.01 The provision of generating plant and other capacity to meet the expected demand for electricity in the Nth year ahead, where N is the lead time required to plan and construct the plant, should start with a thorough knowledge of existing demands. In particular the component demands both by class of consumer, e.g. residential, and by kind of application, e.g. pumping loads, need to be understood. The aim is to understand the <u>causes</u> of variation in the demand for electricity, though often the lesser aim of <u>explaining</u> the variability in terms of likely relationships will have to be accepted.

4.02 Another useful approach is to regard system demand as a single entity, rather than as a combination of the demands of consumer classes or of various applications, but with this entity possibly sensitive to:

Temperature
Wind speed
Illumination
Precipitation
Day of week
Season of year

4.03 An allied approach is to regard fuel usage as an input to economic activity when economic indicators such as the following are used in attempts to explain changes in the demand for electricity:

Gross national product
Industrial production
Total personal income
Total employment
Unemployment
Wholesale prices
Retail prices
Contracts placed
Hours of work
Interest rates
Stock market prices
Business confidence
Credit restrictions

4.04 While it could be argued that such sophistication is out of place in a developing country and that the available data are just not good enough, the cost of studying the available data seems insignificant in relation to the decisions being taken about the scale of investment. Only by studying the available data and questioning their value for system planning will the need for formalized data collection become apparent.

4.05 A simplistic approach to electricity demand data and the associated forecasting problem is to take the observed annual maximum demands for a series of years, to ignore all other demand data, and to assume that a mathematical function can be found which fits the observed maxima and which gives a sound view of the future by reason of its mathematical properties, e.g. constant proportional growth. Both the exponential curve and logistic function are popular candidates in this approach, and regretfully can be shown to fit most sets of electricity demand maxima, without necessarily saying anything of value about the future.

4.06 Even so, perhaps every forecasting approach relies in part on mathematical projection. However, such reliance is less risky if the component class demands, and the various applications of electricity are treated separately, i.e. if the total demand is disaggregated.

4.07 Any proposal to amend an electricity tariff, to introduce a new tariff, or to control loads by technical and administrative devices requires for its serious consideration a forecast of system loading "before" the proposed change and "after" the change. The pay-off, see later, can then be estimated and weighed against the costs of implementing the proposal. It follows, therefore, that load control proposals with an intended economic justification inevitably have a forecasting content. However, where the data are insufficient for an immediate reliable assessment of the worth of the proposal, it may still be feasible to discuss the question as to whether the proposal should be rejected out of hand or should be the subject of an experiment, or other data-gathering exercise.

4.08 Apart from system demand and allied electrical quantities (such as the demand-duration curve) which need to be forecasted, the implementation of tariff changes or load control also requires forecasts of the costs of the hardware and administration. Such forecasts are generally thought to be more easily made than those of system demand. This sanguinity may not turn out to be justified since hardware, in particular, often involves hidden costs in so-called "teething troubles".

4.09 Table 4.1 sets out a few of the most frequently used models of electricity usage. Some of them make only slight demands for data by volume though all of them, being based upon explanations of variability, require the data to be sensible. By "sensible" is meant that each piece of information can be regarded as emanating from a common pool of knowledge, where that pool has certain settled statistical characteristics.

TABLE 4.1

LINEAR REGRESSION MODELS USED TO EXPLAIN ELECTRICITY USAGE

No.	Explained variable	Regressors
1.	System annual maximum demand for a series of years.	Weather data and growth term.
2.	System annual maximum demand for a series of years.	Weather data, economic indicators and growth term.
3.	Demand for given half hour* for series of days in given year.	Weather data and economic indicators. Growth discounted.
4.	Demand for given half hour* for a number of areas in which the coincident annual kWh sales to the different classes of consumer are known.	Weather and economic factors assumed roughly constant over all areas. Annual kWh sales to the consumer classes used as regressors.
5.	Monthly, quarterly or annual consumption for a series of years.	Weather data, economic indicators and growth term.

* Repeat analysis for successive half hours to generate demand pattern.

4.10 This study in West Pakistan showed that electricity usage data as now collected could not, in general, be regarded as sensible. For the system itself, the limitations of supply, both nationally and locally, governed demand so that many reductions in demand are merely the result of supply limitations. Unfortunately, this seriously hampers the study of demand under the expected future conditions of better quality supply. For individual 11 kV feeders, which are a valuable source of data about component demands, e.g. tubewells and industry, there is evidence of tampering with the outgoing metering from grid substations in certain cases. 1/ In other cases, a feeder switch may be taken out of service for repair and its feeder temporarily combined with another, i.e. two on one switch. For individual consumers, especially private tubewells, the valuable information which could be obtained about seasonal variations in usage from billing data is distorted by pilferage of energy and irregular readings.

4.11 With this background in mind, only the simplest of statistical techniques were attempted, and unhappily great use had to be made of arbitrary judgment in rejecting data thought to be distorted in the light of all the available evidence. Day-of-week effect for total system demand in 1969/70 of the Northern grid was first examined. As expected, Sunday had lower demands than on working days, see Figure 4.1. Friday, in part a rest day, similarly had low demands, but the other five days could be grouped indifferently as working days.

4.12 Some of these working days defined as Monday to Thursday plus Saturday were in fact public or religious holidays. Daily maximum demands for the remaining working days are plotted in Figure 4.2 together with their mean for each month. The mean values usefully display the seasonal variation in demand, with the highest value in January and the lowest in July. The statistic

$$\frac{\text{Range of variation}}{\text{Mid-range}} = \frac{710 - 630}{670}$$

$$= 12\%$$

shows that the seasonal variation in demand is slight.

4.13 Daily departures from the monthly mean rarely exceed 50 MW, i.e. 7% or so, but 3% departures are commonplace. The open scale of Figure 4.2 therefore perhaps gives an exaggerated view of the daily variability. In December, the climbing values over the month might be systematic and associated with earlier darkness. Similarly the January values might be steadily declining.

4.14 Figure 4.3, Sections (a) to (d), shows a likely relationship between summer temperatures (daily maxima) and system demand. In spite of the great scatter, it can be said that summer demand on the Northern grid can be expected to increase by 30 MW or so for a 10° F rise in temperature.

1/ In one case when an industrial consumer was seen to be taking supply, his own meter was rotating, but at the other end of the feeder the ammeters read zero. And yet mysteriously they, the ammeters, "recovered" every night only to "fail" again next day. As reported for load study, this consumer and another had a preferential use of night energy but they admitted to a 24-hour steady load. Obviously this play-acting had some reason, which the consultants did not explore.

Certainly, these tentative relationships need to be examined every year in that they might well reveal increases in the cooling load and temperature sensitivity. Equally, but not attempted, useful relationships might be discovered between pumping loads and rainfall in some months and possibly other explaining variables.

4.15 Granted that the causes of variation in system demand are not yet understood, Figure 4.4 shows that on a day of high maximum demand, closely approaching the annual maximum, demand was within 20% of the day's peak from 7 a.m. to 9 p.m. The night valley showed a 40% reduction at the minimum. On a day of low maximum demand, the evening peak from say 5 p.m. to 9 p.m rose by about 100 MW above the daytime plateau. This broadly suggests a variable winter lighting component of that order.

4.16 Figure 4.5, taken from Utilization Research Report No. 72 "Analysis and Adjustment of Area Board Demand Data: An Aid to Forecasting" (The Electricity Council, London), shows how winter demand on part of the British electricity supply system was found to be responsive to both temperature and illumination. That report describes in detail the method of fitting a simple mathematical model to demand data. The model deals with day-of-week, temperature and illumination as explaining variables for a succession of half-hourly electricity demands on winter working days, see item 3 of Table 4.1. Subsequently, daily load curves can be estimated under standard weather conditions, which standardized curves are of value for demand forecasting for the years ahead.

4.17 While the demand data collected for WAPDA's Northern grid do not in Figures 4.2 or 4.3 show the obvious regularity of Figure 4.5, it does not follow that systematic study of WAPDA's demand will not in time reveal useful statistical regularities. Such studies should be encouraged. 1/

4.18 Component demands, especially of tubewells, were the subject of special study. Without doubt the most reliable source of information as to component electricity usage by time of day would be obtained by installing demand recorders at consumers' terminals for a probability sample of the required kind of consumer. Demands are recorded against time, often on a magnetic tape with the intention of processing the data automatically by computer. Pen recorders, which are often alternatively proposed for this task

---

1/ Selected references are:

"The Relationship Between Weather and Electricity Demand" by M. Davies, I.E.E. Monograph No. 314S, October 1958.

"The Relationship Between Weather and Summer Loads - A Regression Analysis" by G.T. Heinemann, D.A. Nordman and E.C. Plant, IEEE Trans. Power Apparatus and Systems, vol. PAS-85, pp. 1144-1154, November 1966.

DAY OF WEEK EFFECT

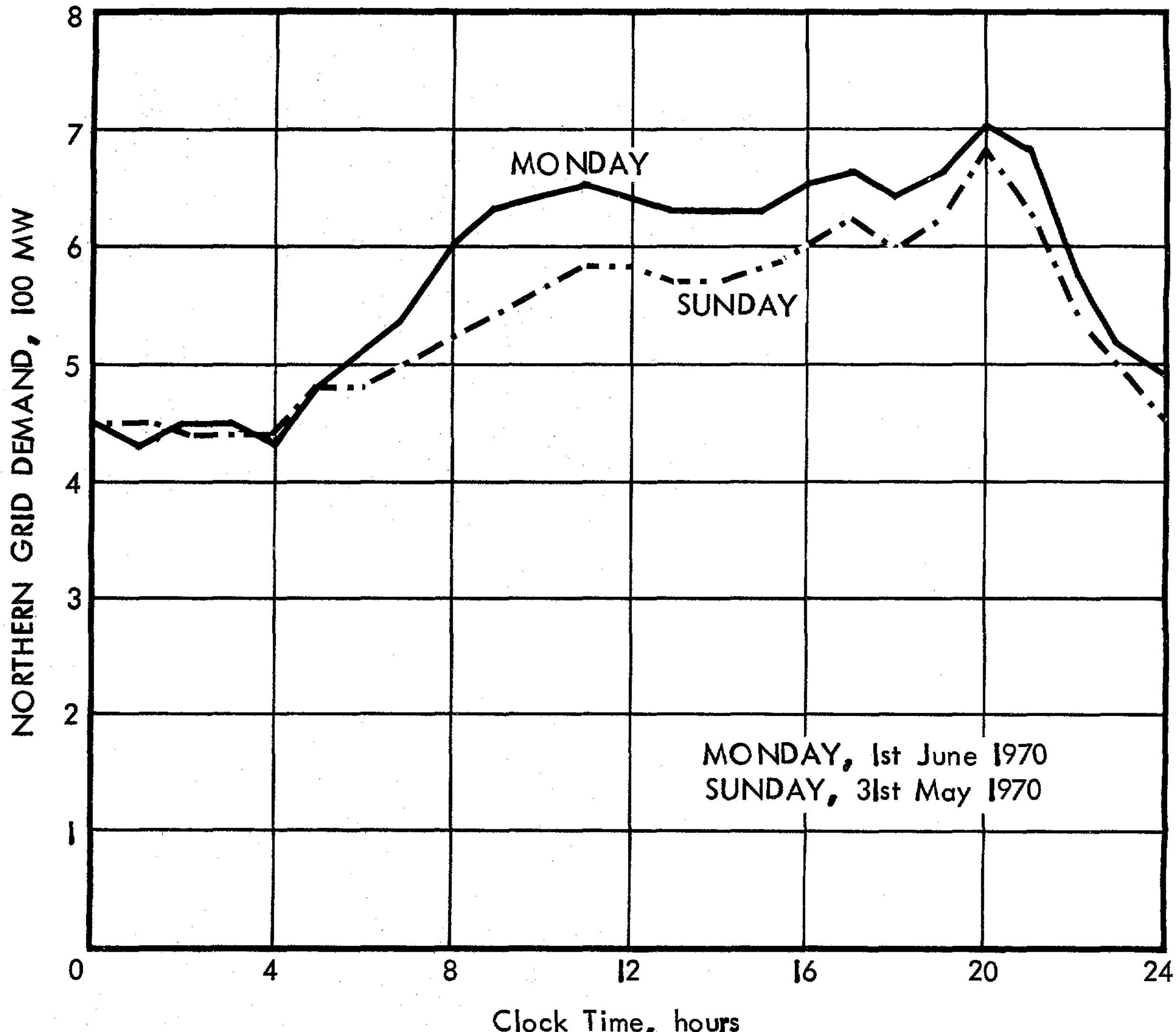

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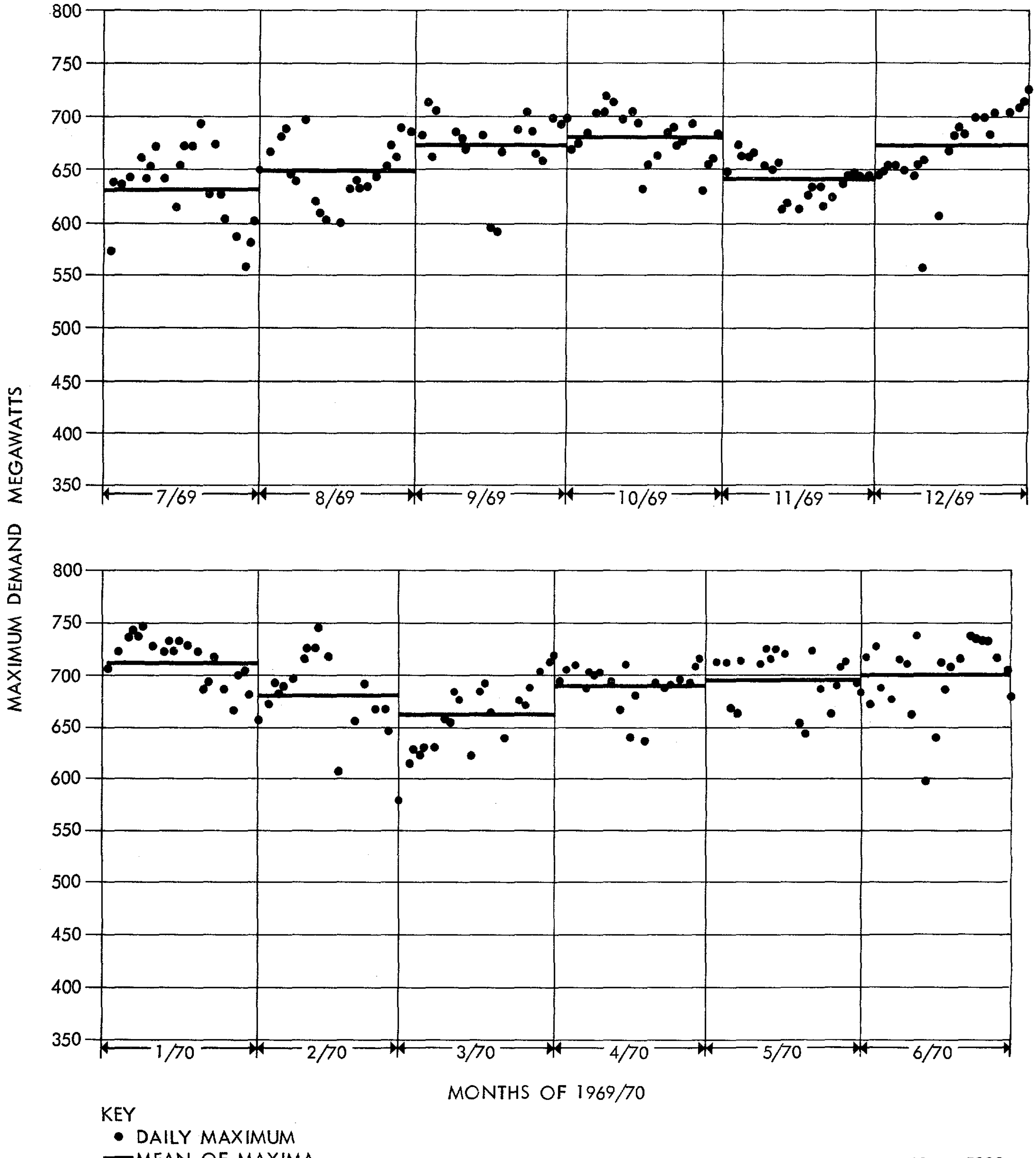
FIGURE 4.2

DAILY MAXIMA OF NORTHERN GRID ON NORMAL WORKING DAYS

(ALSO SHOWN ARE THE MONTLY MEANS OF THE DAILY MAXIMA)



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DEMAND TEMPERATURE SENSITIVITY OF SUMMER DEMANDS (WAPDA NORTHERN GRID)

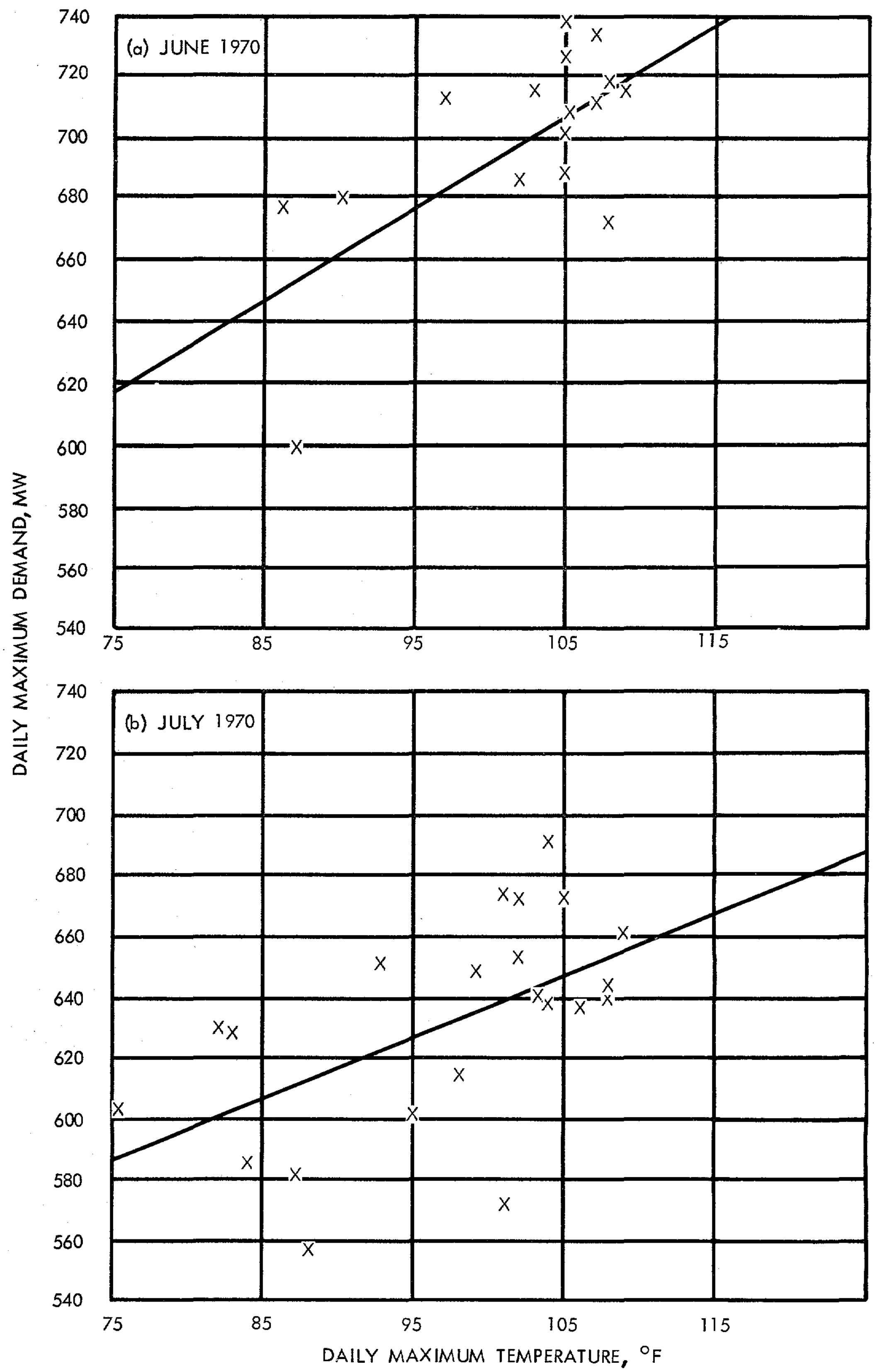

FIGURE 4.3

DEMAND TEMPERATURE SENSITIVITY OF SUMMER DEMANDS
(WAPDA NORTHERN GRID)

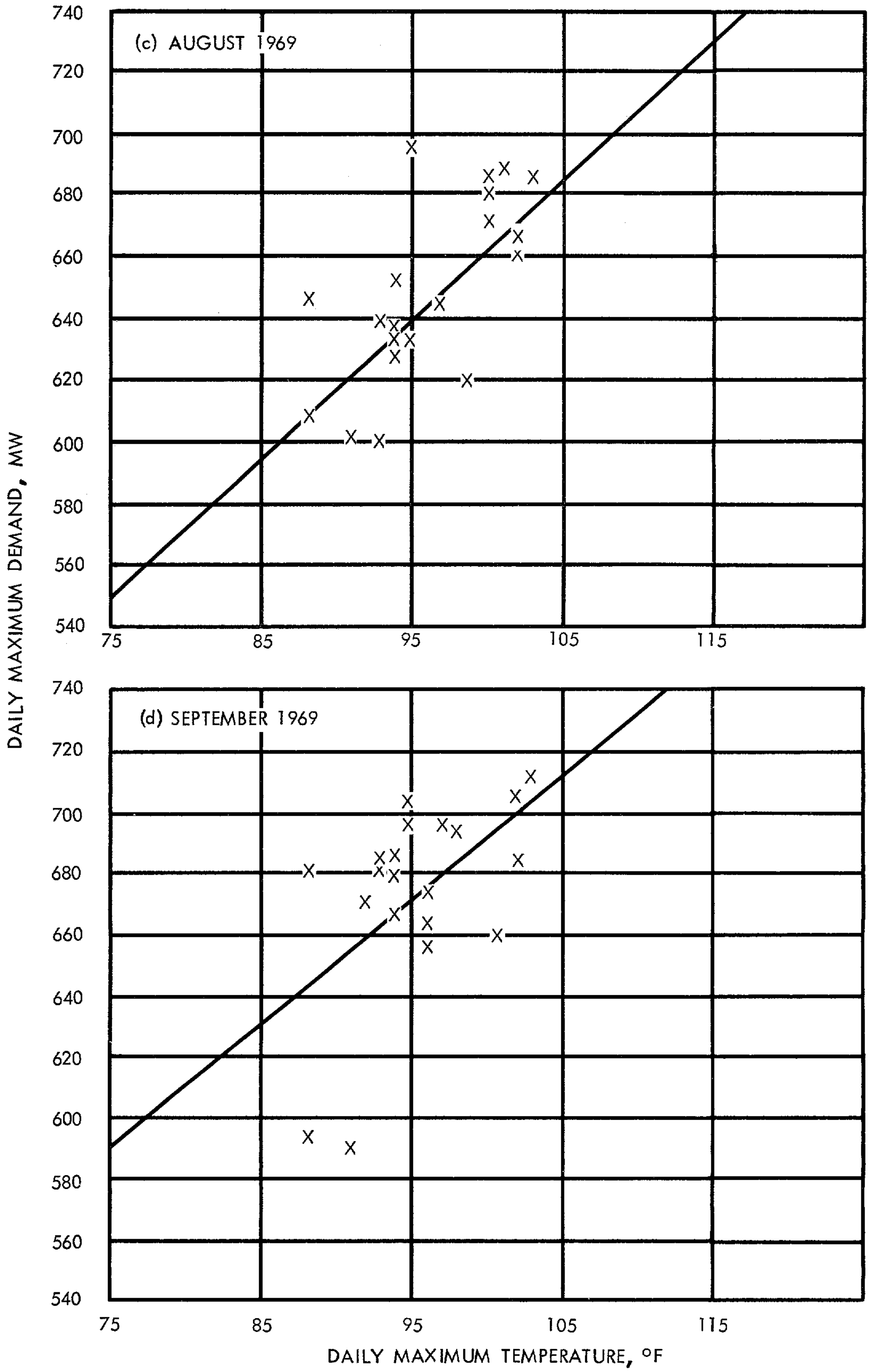

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FIGURE 4.4

EXAMPLES OF HIGH & LOW DEMANDS

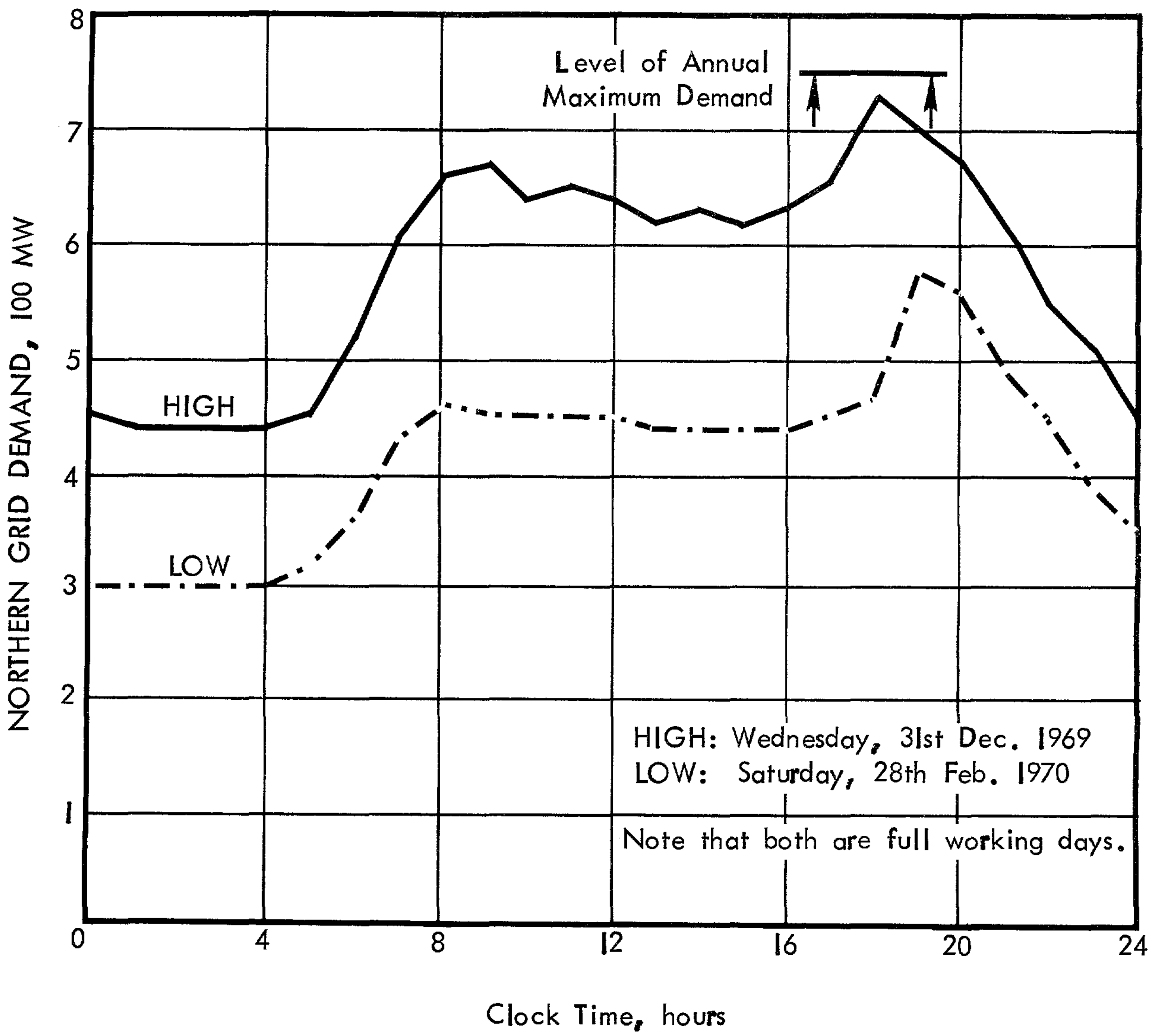

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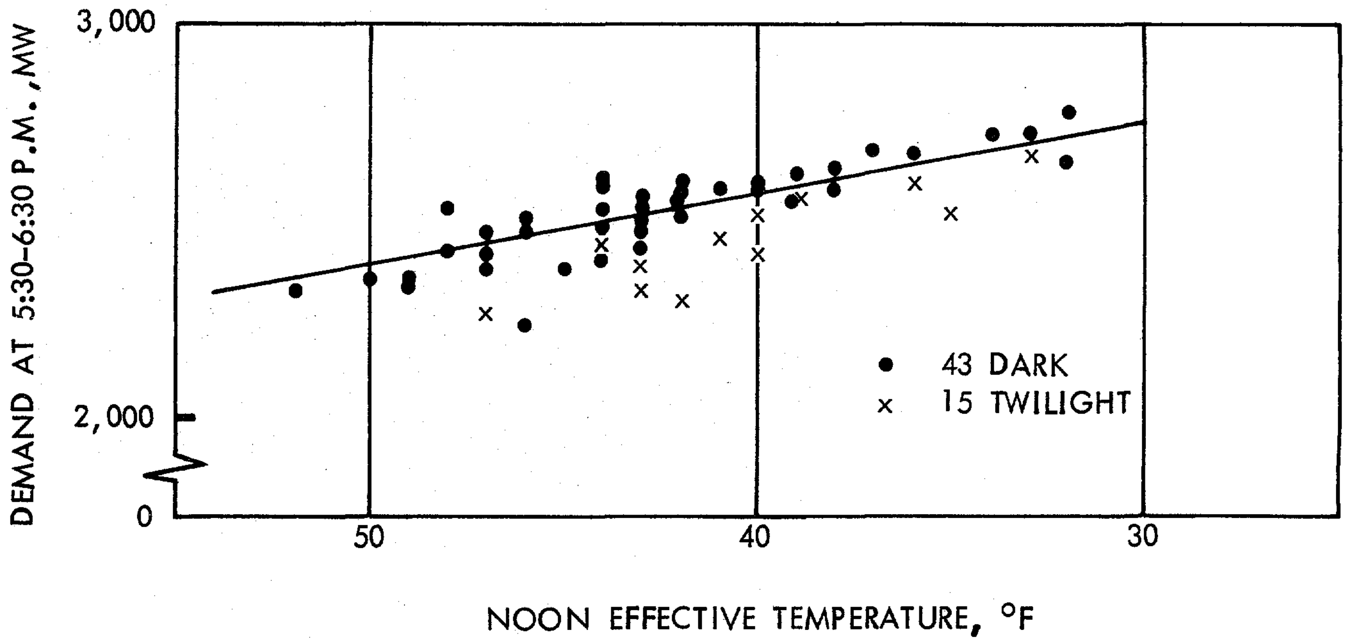
FIGURE 4.5

DEMAND RESPONSIVENESS TO TEMPERATURE AND ILLUMINATION IN THE MIDLANDS OF BRITAIN



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as low-cost off-shelf items, give traces which are ambiguous and difficult to interpret. All recorders suffer from timing difficulties, but with pen recorders the demand values themselves, granted the usual volatility of instantaneous demand, are confused. Such confusion of demand values, and uncertainties as to timing, combine to make the preparation of the computer input a formidable task. The task can be made a reasonable one by reducing the sample size to, say, 10 or 20 consumers when the sampling variance in practice becomes excessive. It follows that pen recorders cannot be recommended for this purpose if serious studies are being attempted.

4.19 Only two special-purpose magnetic tape recorders deserve serious consideration (ignoring high-quality, above US$10,000 each, scientific recorders). They are both in regular batch production. Westinghouse (USA) have for many years made a simple quarter-inch tape recorder, which accepts demand impulses from modified energy (kWh) meters, and which is driven at constant velocity governed by the supply frequency. The instrument is in widespread use in North America and facilities for translating the magnetic tapes to punched cards are readily available.

4.20 In Britain, under the guidance of the Electricity Council, see Figure 4.6, the essential principles of the well-tried Westinghouse recorder have been kept, namely constant-velocity drive and constant-value impulse recording without encoding, but greater attention has been paid to major errors in timekeeping under adverse supply conditions. A 36-hour spring-reserve time switch on the left of the diagram puts a daily time-check on the 35mm. oxide-coated film. 1/ Very fast playback has been arranged and a month's record is translated in one minute.

4.21 However, whether either of these recorders would succeed under the adverse supply and climatic conditions of West Pakistan could only be settled by practical trials. Alternative methods of estimating component demands requiring no investment in recorders will now be described but it is as well to realize from the outset that the alternatives in general sacrifice the great advantages of:

a. clear definition of what loads are being measured;

b. a probability sample can be claimed to represent the population of defined consumers with both theoretical and practical justifications for the claim; and

c. the errors attributed to sampling can be estimated and in principle reduced to any desired level.

1/ The price of this recorder is about US$350. The Westinghouse version is similarly priced. Another designed by Electricite de France is much more expensive.

The popular viewpoint that studies based on (small) samples are automatically inferior to global studies is not supported and, in fact, the contrary can be persuasively argued.

4.22 An important alternative method of broadly estimating component loads, which has already been used in paragraph 4.14 above, is to infer the component from the variations in total system demand by day-of-week, varying temperature, illumination and so on. Only the variable part of any component load can be discovered by this method. Furthermore it is difficult with such correlation studies to say what precisely is meant by the load which is associated with changes in illumination, for example. These technical difficulties should not, however, be used to denigrate such estimates where the alternative is unsupported judgment.

4.23 Another class of correlation study, item 4 of Table 4.1, has been used in Britain for over fifteen years to analyze total system demand into demand components associated with the annual consumptions of component consumer classes, e.g. domestic, commercial and industrial. For example, the model with three components would be

$$P = b_1x_1 + b_2x_2 + b_3x_3$$

where x_1 = annual kWh sales to the domestic (residential) class of consumer

x_2 = annual kWh sales to the commercial class of consumer

x_3 = annual kWh sales to the industrial class of consumer

and where P = demand on a particular day and for a given half hour.

By repetition the process generates component load curves for selected days of interest.

4.24 Annex 4 describes the method in detail. Alternatively it can be described in terms of input and output. The inputs are total demand and component kWh sales for supply catchment areas, called sub-areas in Annex 4, where the number of sub-areas has to be (much) greater than the number of component demands being estimated. Another input is computer time. For large supply systems subdivided into administrative areas, these data may be readily available as by-products of the accountancy arrangements. In that case the model makes use of low-cost data and additionally the computing costs with standard-package computer programs will also be low.

4.25 The output consists of estimates of component load curves, half hour by half hour and day by day, for the time periods studied. These estimates, particularly if reinforced by measurements of demands of samples of consumers, are helpful in system demand forecasting and of great value

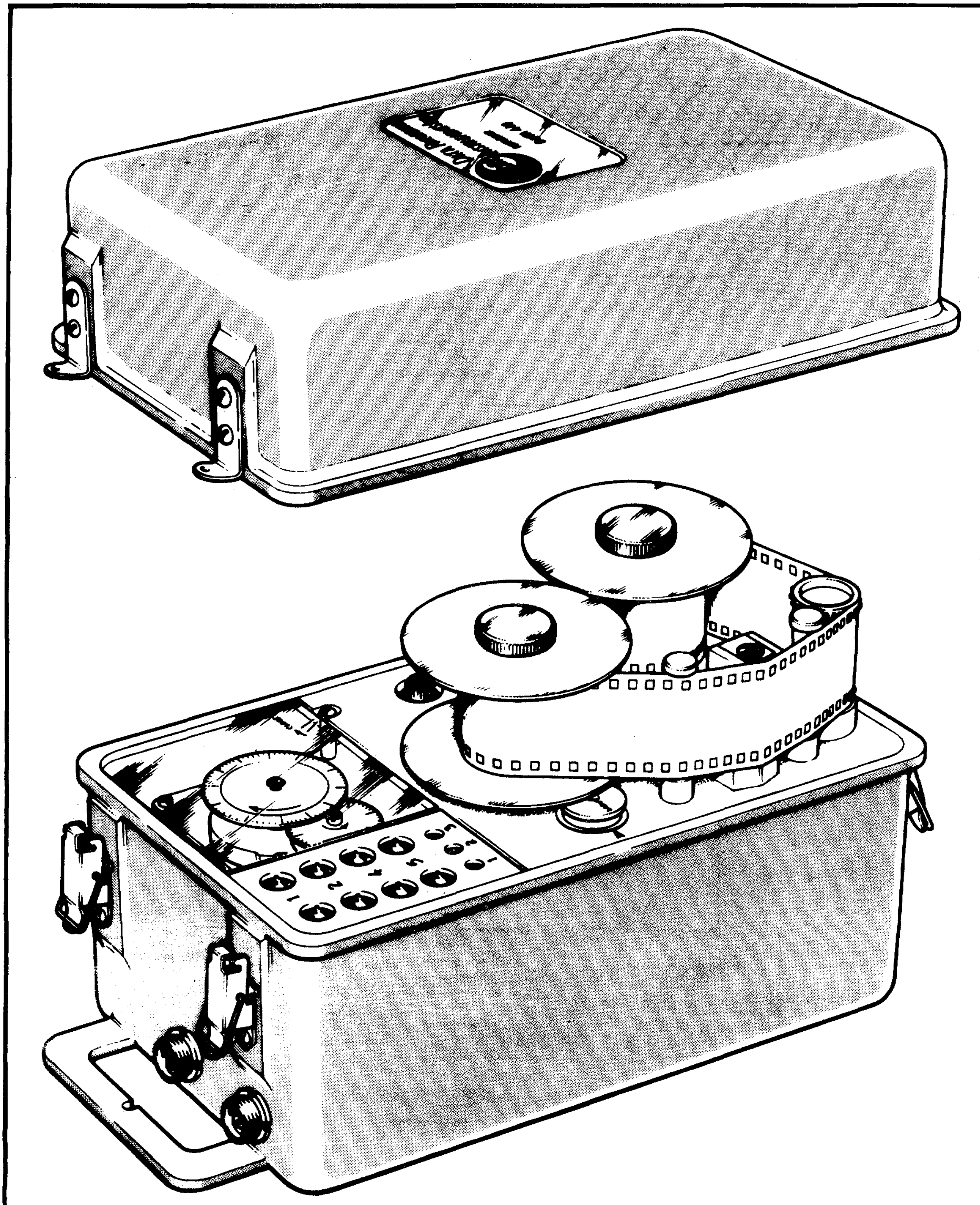

Figure 4.6 - A special-purpose magnetic tape recorder designed to receive impulses representing electricity usage from a modified kWh meter and to record these against time. Playback is at high-speed with translation into punched paper tape for computer input. A suite of computer programs is available to calculate the group average demand curves and other statistics required for commercial considerations.

in tariff making. However, until data quality is improved in West Pakistan, the method is unlikely to succeed in that the statistical inferences are sensitive to imperfections in the data.

4.26 An easy method of collecting data about consumer class components, such as private tubewells, is to look for small supply systems where that component load is predominant. Hopefully other disturbing loads will be insignificant or possibly adjustments can be made with little risk of error. The requirements for the installation of demand recorders or other data gathering activities are then minimal. Also it seems, at first sight, as if the requirements for an adequate sample size (paragraph 4.21) have been circumvented. For example, in Britain, one residential-area 11kV to 415/240V substation may supply 300 homes and in West Pakistan one 11 kV feeder may supply 150 private tubewells. With a few residential substations or a few tubewell feeders, a "sample size" of, say, 1,000 can be readily generated with the aid of the 300 or 150 to 1 gearing. Unfortunately the argument is unsound and the samples obtained by haphazard "grab what comes to hand" techniques have sampling variances and biases of unknown magnitudes. Experience in Britain suggests that differences between <u>small</u> systems can be very great and in West Pakistan different crops with different irrigation patterns are grown in the different regions.

4.27 The necessary assumption of a constant catchment area over the longest time period studied, e.g. over the year, of the small supply system also turns out in practice often to be violated. Engineering maintenance work is often carried out by merging systems with little regard to record keeping. Nonetheless, granted that this cheap and facile method of collecting component demand data has fundamental weaknesses, it remains a practical method for use with limited resources and was therefore chosen. Fortunately in West Pakistan nearly the whole of the supply system at 11 kV consists of simple radial feeders, radiating from grid substations and with few possibilities of interconnection.

4.28 At each grid substation the hourly currents in amperes are recorded on the usual daily log sheets for each feeder. Additionally, as part of the Action Plan to reduce losses, for the past year records have been kept -- sometimes hourly and sometimes daily -- the per-feeder energy sent out in kWh and the energy received. A simple form to collect these data, and the accompanying instructions to field investigators, are given in Annex 5. The field work was carried out by the Power Market Survey field force.

4.29 For each month of 1969/70 a working day was selected with the following desirable characteristics:

a. the daily maximum was near the monthly mean of working-day maxima. In Figure 4.2 the day's demand was near to the solid line. This made the daily demand patterns of the chosen days over the year follow a broad-based estimate of the global seasonal variation. It also eliminated days where the supply was unusually restricted. In short the day's demands were thought to be typical of high demands; and

b. the succession of selected dates were usually in the central third of each month (10th to 20th) and had 30-day or so spacings. This choice was intended to bring out any month-to-month variations in the demand patterns.

To some extent the desiderata were conflicting.

4.30 A second-choice or substitute day was also chosen and for either day, see Annex 5, for each month of the year 1969/70, 24-hourly demand values were collected. Most were given as currents in amperes which were later multiplied by 15.4 (=11.2kV x 0.8p.f.x 3) to give demand in kW. Hourly values obtained from the advances of energy meters proved to be disappointing in that the meters hardly moved over an hour, but in contrast the daily advances of kWh were a most useful check on the validity of the calculated factor of 15.4; for example, in four checks the factor came out as 13.8, 15.0, 14.5 and 15.0.

4.31 As indicators of the kind of load supplied from an 11 kV radial feeder, the following data were collected from local distribution offices:

> Number of consumers and connected load in kW for the following categories:
>
> Residential and commercial (as one category-connected load not available)
> Small industry (under 70kW each connected)
> Medium industry (70 up to 500kW each)
> Large industry (each 500kW and over)
> Tubewells, public (SCARP or irrigation)
> Tubewells, private
> Other load, but only if important

This gave six or seven categories. The subdivisions of industry are those used in WAPDA's tariffs.

4.32 Two approaches were visualized to the collected demand data. With either approach, the data would first be scrutinized, presented uniformly as kW, and obviously anomalous data rejected. The simplest approach would be to search the feeder descriptive data (see previous paragraph) to find those feeders with dominant loads, e.g. almost entirely private tubewells. Provided the other categories of load were relatively small, they could be dealt with by two approximations:

a. the scale divisor, e.g. the number of private tubewells, could be inflated to take care of the additional demand. This correction assumes that the interfering loads have roughly the same demand patterns as the dominant load though in practice the assumption can be of no importance; and

b. the interfering load on one feeder could be estimated, via the ratio of connected loads, from the dominant load on another. By an iterative process "best estimates" of the separate categories of load could be found.

4.33 Item (b) above leads on to the second approach which is a formal statistical method (multiple regression) of reconciling the many sets of feeder data to give "best estimates" of the component demands for the six (or seven) categories of load. A brief description is given in Annex 6. This method uses all the available data in a systematic way, has a respectable theoretical background, 1/ and is fairly easy to apply in practice given well-behaved data. However, the collected data were far from well-behaved so that the simpler, more robust approach of the previous paragraph was used. Some of the troubles with the data have been mentioned in paragraphs 4.10, 4.26 and 4.27.

4.34 Figure 4.7, Sections (a) to (f), shows the results for private tubewells of the 11 kV feeder study for each of the 12 months of 1969/70. The demands, which peak at 8.4 kW in August around noon, are expressed as an average demand per tubewell. 2/ Demands at consumers' terminals might be 7% or so less but fortunately no allowance for pilferage is needed (in theory at least) with feeder demand data. The data themselves are listed in Table 4.2 and by assuming 28 equivalent working days to each month, the monthly and annual energy usages of Table 4.3 were obtained. The annual consumption estimated in this way of 22,000 kWh contrasts with a figure of 14,000 kWh based on billing data. 3/

1/ The theoretical background is partly given in Annex 4 for a slightly different model of demand analysis. The main changes are that connected loads are used as the regressors instead of annual consumptions.

2/ American texts would call this quantity "the average diversified demand per customer" and British ones "the after-diversity demand per consumer". Neither usage is liked.

3/ IBRD, Report by Consultants, Indus Basin Review Mission, June 1970, p. 163.

TABLE 4.2

ESTIMATED WORKING-DAY AVERAGE DEMANDS PER CONSUMER FOR PRIVATE TUBEWELLS

(Based on 11 kV feeder data)

Average demand per private tubewell, kW

Hour	JULY 1969	AUG. 1969	SEP. 1969	OCT. 1969	NOV. 1969	DEC. 1969	JAN. 1970	FEB. 1970	MAR. 1970	APR. 1970	MAY 1970	JUNE 1970	Average
01.00	5.0	2.0	1.5	1.6	0.9	0.6	0.6	0.3	0.6	0.3	0.3	1.2	1.2
02.00	5.0	2.0	1.5	1.6	0.9	0.6	0.6	0.3	0.3	0.3	0.6	1.2	1.2
03.00	5.4	2.0	1.5	1.6	0.9	0.6	0.6	0.3	0.3	0.3	0.6	1.5	1.3
04.00	4.5	2.0	1.5	2.0	0.9	0.6	0.6	0.3	0.3	0.6	0.9	2.4	1.4
05.00	3.5	3.0	1.5	2.2	0.9	0.6	0.6	0.3	0.3	0.6	0.9	5.4	1.6
06.00	6.0	6.0	5.4	2.6	0.9	0.6	0.6	0.3	0.6	0.6	0.9	6.0	2.5
07.00	6.3	6.8	6.0	5.4	1.2	0.9	0.6	0.3	0.6	1.2	1.2	6.0	3.0
08.00	6.0	6.4	6.0	4.0	1.2	0.9	0.6	0.6	1.2	1.2	1.2	3.0	2.7
09.00	7.2	6.3	6.0	3.0	1.2	0.9	1.2	0.6	1.8	1.2	1.2	4.8	3.0
10.00	7.2	6.6	6.0	4.5	1.2	0.9	1.8	0.6	1.8	1.2	1.2	6.0	3.2
11.00	6.0	8.4	6.0	5.7	1.2	1.2	1.8	0.6	2.4	1.8	1.5	5.1	3.5
12.00	6.0	8.4	6.0	6.0	1.8	1.2	1.8	0.6	5.7	1.8	1.5	5.1	3.8
13.00	6.0	8.4	6.3	6.0	1.8	3.0	1.8	0.6	4.8	1.8	1.8	5.1	4.0
14.00	6.0	6.6	6.6	6.0	1.8	3.0	1.8	0.6	4.8	1.8	1.8	5.1	4.2
15.00	6.0	6.6	6.3	5.4	1.8	2.4	1.5	0.6	4.2	1.8	1.8	5.1	3.6
16.00	5.7	6.6	6.6	5.7	1.8	1.8	1.5	0.6	4.2	1.8	1.8	5.1	3.6
17.00	6.0	7.2	6.6	5.7	1.8	1.5	1.5	0.6	3.6	1.8	1.8	5.7	3.6
18.00	6.0	7.8	6.6	5.2	1.8	1.5	1.5	0.6	3.0	1.5	1.8	6.0	3.6
19.00	6.0	7.2	5.7	3.6	1.8	1.2	1.2	0.6	2.7	1.2	1.8	5.4	3.2
20.00	6.0	6.0	4.8	3.6	1.4	1.2	1.2	0.6	1.2	1.2	1.2	5.1	2.8
21.00	5.1	5.7	4.5	2.4	1.4	0.9	0.9	0.3	0.9	0.6	0.9	4.8	2.3
22.00	4.6	5.4	4.2	2.4	1.4	0.9	0.6	0.3	0.9	0.6	0.9	3.0	2.1
23.00	4.4	5.4	4.2	2.1	0.9	0.9	0.6	0.3	0.9	0.3	0.6	2.1	1.9
24.00	4.4	5.4	3.9	2.1	0.9	0.6	0.6	0.3	0.9	0.3	0.6	1.5	1.8
Average	5.6	5.7	4.8	3.7	1.3	1.2	1.1	0.5	2.0	1.1	1.2	4.2	2.7

WORKING DAY DEMAND CURVES 1969/70

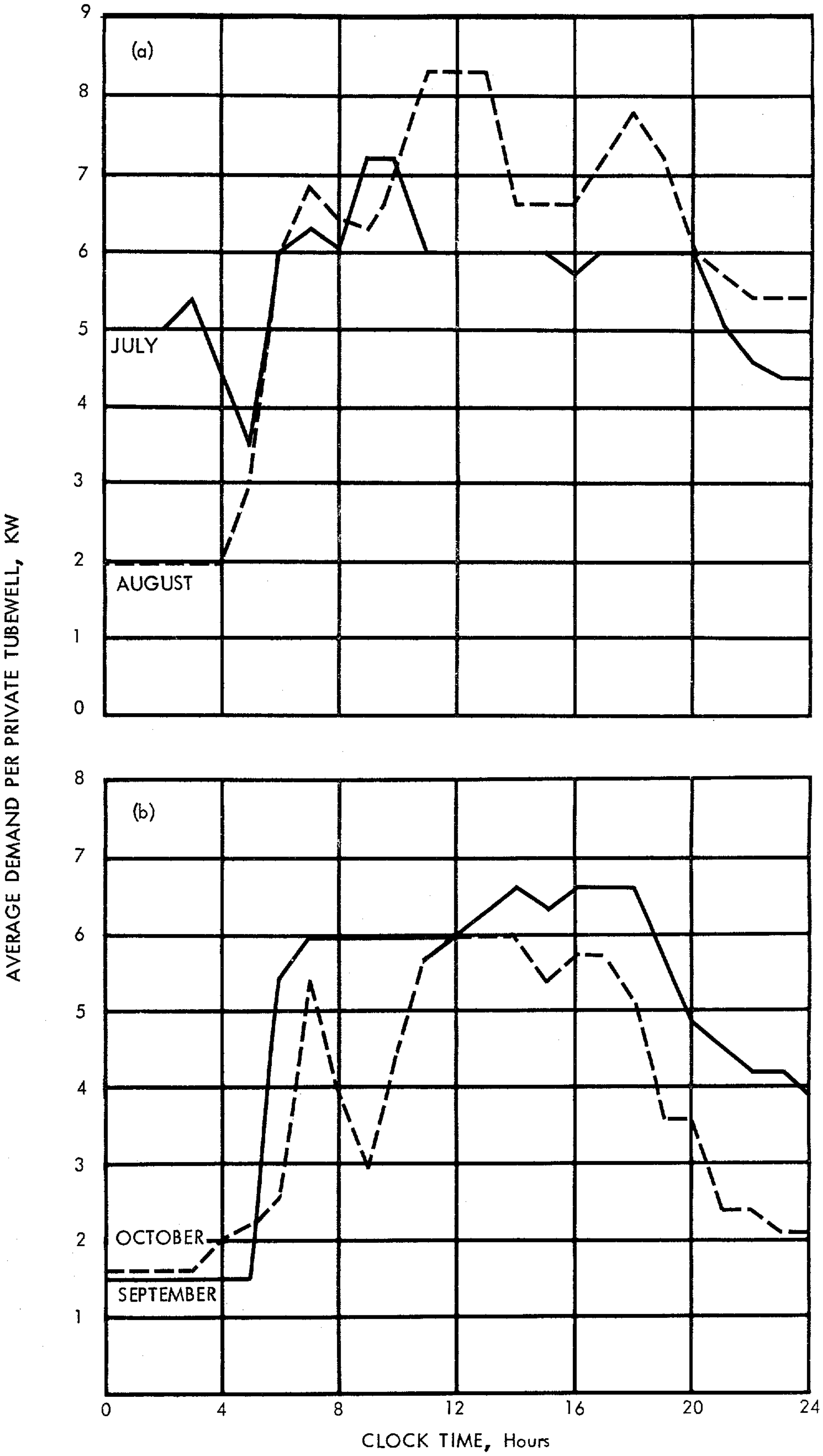

FIGURE 4.7

WORKING DAY DEMAND CURVES 1969/70

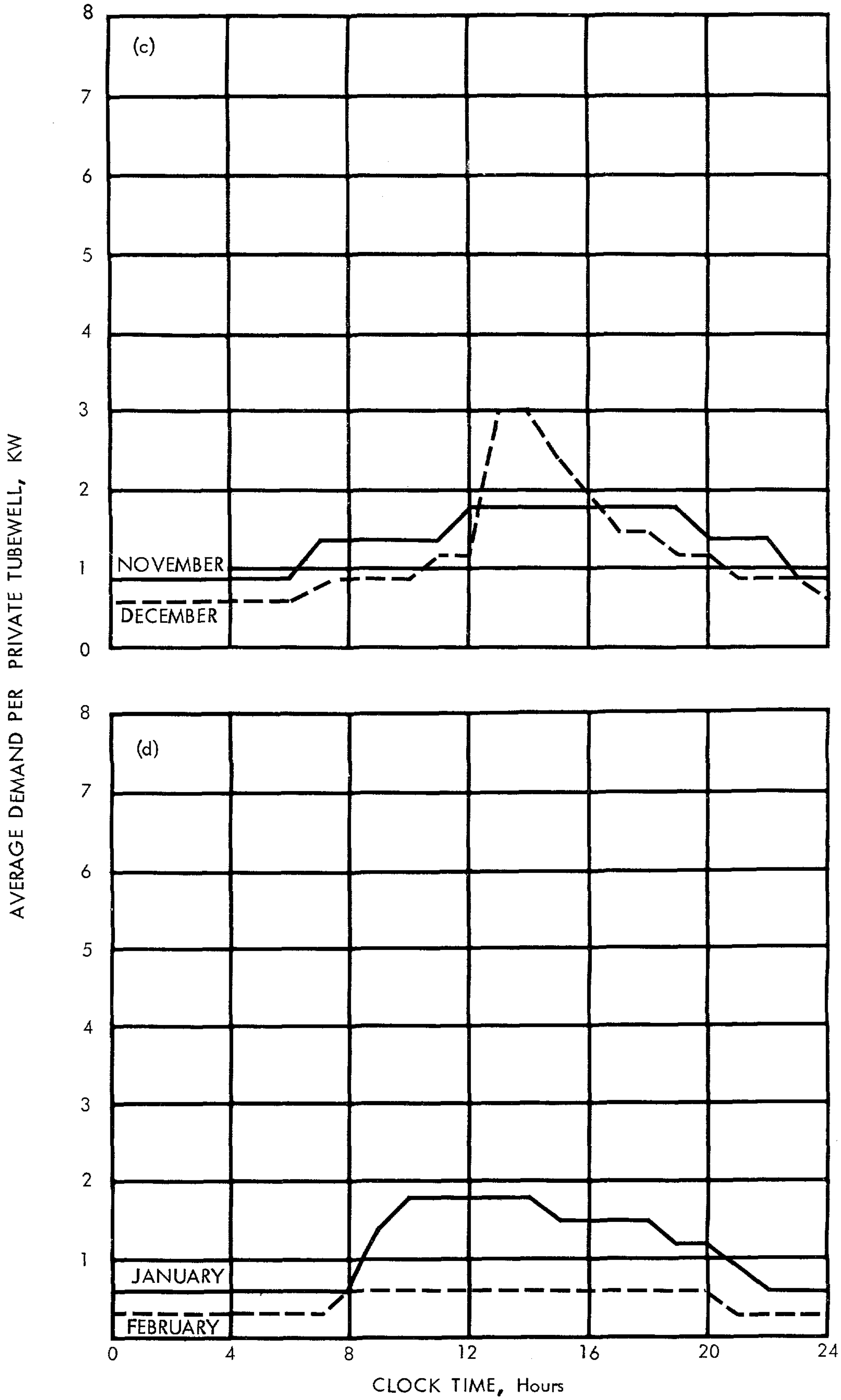

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FIGURE 4.7

WORKING DAY DEMAND CURVES 1969/70

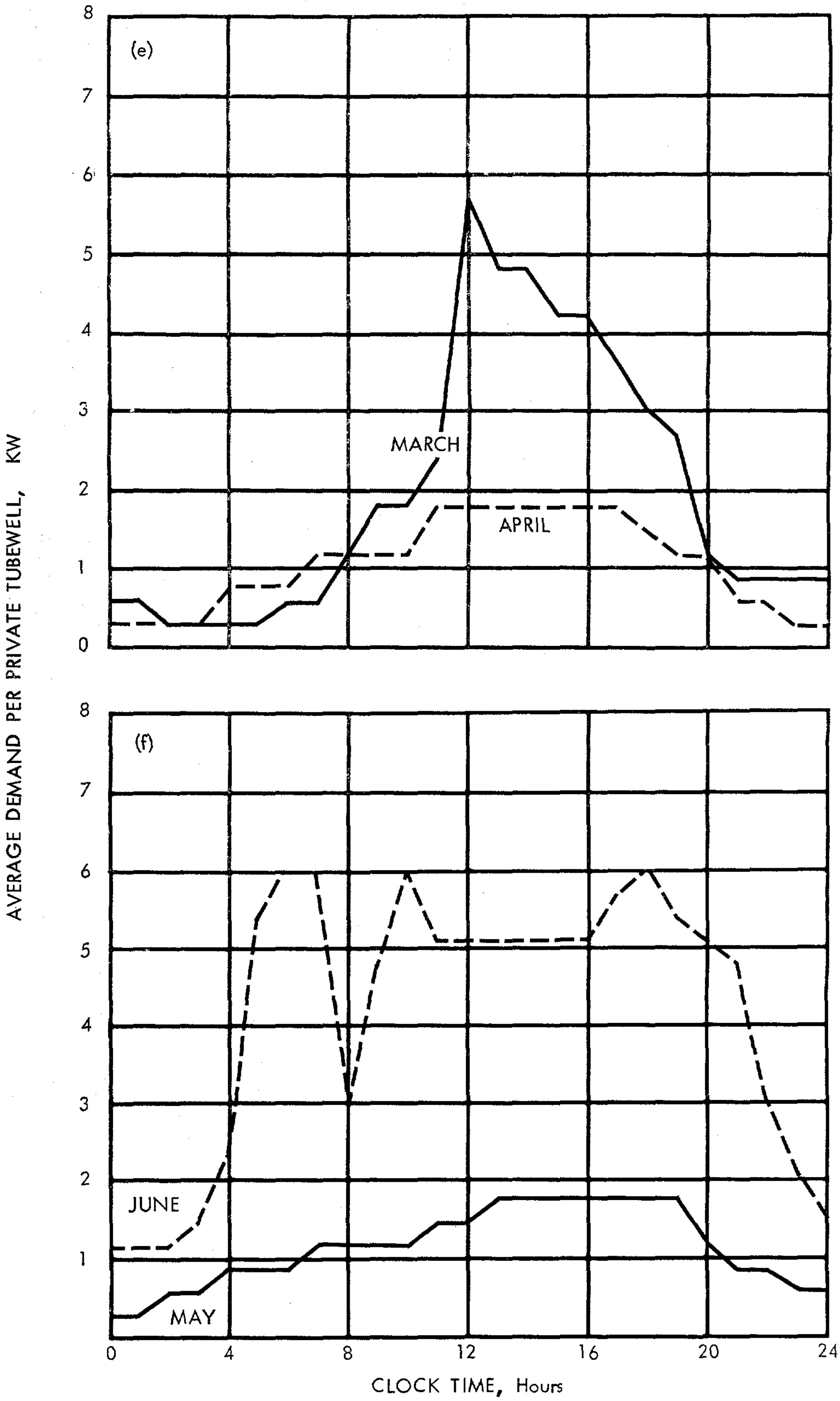

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TABLE 4.3

PRIVATE TUBEWELLS

Estimated Monthly and Annual Consumption

Month	kWh per Well	Pro-rated to 100%
July	3,760	17.2
August	3,869	17.7
September	3,225	14.8
October	2,531	11.6
November	890	4.1
December	798	3.7
January	730	3.3
February	310	1.5
March	1,344	6.2
April	722	3.3
May	806	3.7
June	2,847	13.0
Annual Total	21,832	100.0

4.35 Figure 4.8, Sections (a) to (f), shows the corresponding results for public tubewells. The private ones average about 10 kW (13 hp) installed, whereas the public tubewells are thought to have an average installed load of 25 kW (33 hp). For public tubewells the data given in Figure 4.8 and in Tables 4.4 and 4.5 need to be multiplied by the estimated installed load. The average consumption of 2,883 x 25 = 72,100 kWh corresponds to a total public tubewell consumption of 340 million kWh in 1969/70. This seems as expected to agree with the billing data 1/ since in this case pilferage should not be a problem.

1/ WAPDA's statistical grouping of sales under "Agricultural" of (1) Private tubewells, (2) Public tubewells and (c) Other agriculture is most unhelpful. The breakdown would greatly assist demand, energy and revenue forecasting.

TABLE 4.4

ESTIMATED WORKING-DAY DEMAND FACTORS FOR PUBLIC TUBEWELLS

(Based on 11 kV feeders)

Proportion of installed load in use, %

Hour	JULY 1969	AUG. 1969	SEP. 1969	OCT. 1969	NOV. 1969	DEC. 1969	JAN. 1970	FEB. 1970	MAR. 1970	APR. 1970	MAY 1970	JUNE 1970	Average
01.00	52	24	37	40	9	11	30	21	14	40	41	46	30
02.00	52	24	37	40	9	11	30	21	18	40	41	46	31
03.00	52	24	37	40	9	12	30	21	18	40	41	46	31
04.00	52	24	37	40	9	12	36	21	18	40	41	50	32
05.00	57	24	40	40	12	12	39	21	18	40	41	50	33
06.00	60	24	45	40	12	15	46	21	18	50	51	50	36
07.00	63	36	45	40	18	15	39	27	18	50	51	42	37
08.00	63	36	45	40	18	20	39	27	29	50	52	42	38
09.00	67	42	50	50	20	20	43	27	25	45	52	55	41
10.00	67	42	61	40	20	25	45	27	29	45	51	55	42
11.00	67	42	50	47	20	25	45	29	29	45	52	55	42
12.00	58	50	45	47	20	25	45	30	29	45	52	55	42
13.00	54	50	45	47	25	25	45	30	25	45	52	45	41
14.00	56	44	50	47	25	25	39	25	29	45	52	45	40
15.00	63	44	48	47	25	25	39	29	30	40	48	45	40
16.00	63	44	48	47	25	16	45	40	30	40	48	45	41
17.00	63	44	48	35	25	16	45	40	25	40	48	43	39
18.00	54	43	50	35	18	11	45	29	29	40	38	43	36
19.00	52	43	39	35	18	11	25	30	21	36	37	43	33
20.00	52	35	39	35	18	11	25	30	21	36	35	40	31
21.00	52	35	36	35	18	11	25	30	20	36	43	40	32
22.00	52	35	23	30	9	9	21	30	20	36	43	40	29
23.00	52	35	23	30	9	9	21	21	20	36	43	40	28
24.00	52	35	23	30	9	7	25	14	21	36	43	40	28
Average	57	37	42	40	17	16	36	27	23	42	46	46	36

FIGURE 4.8

WORKING DAY DEMAND CURVES 1969/70

PUBLIC TUBEWELLS

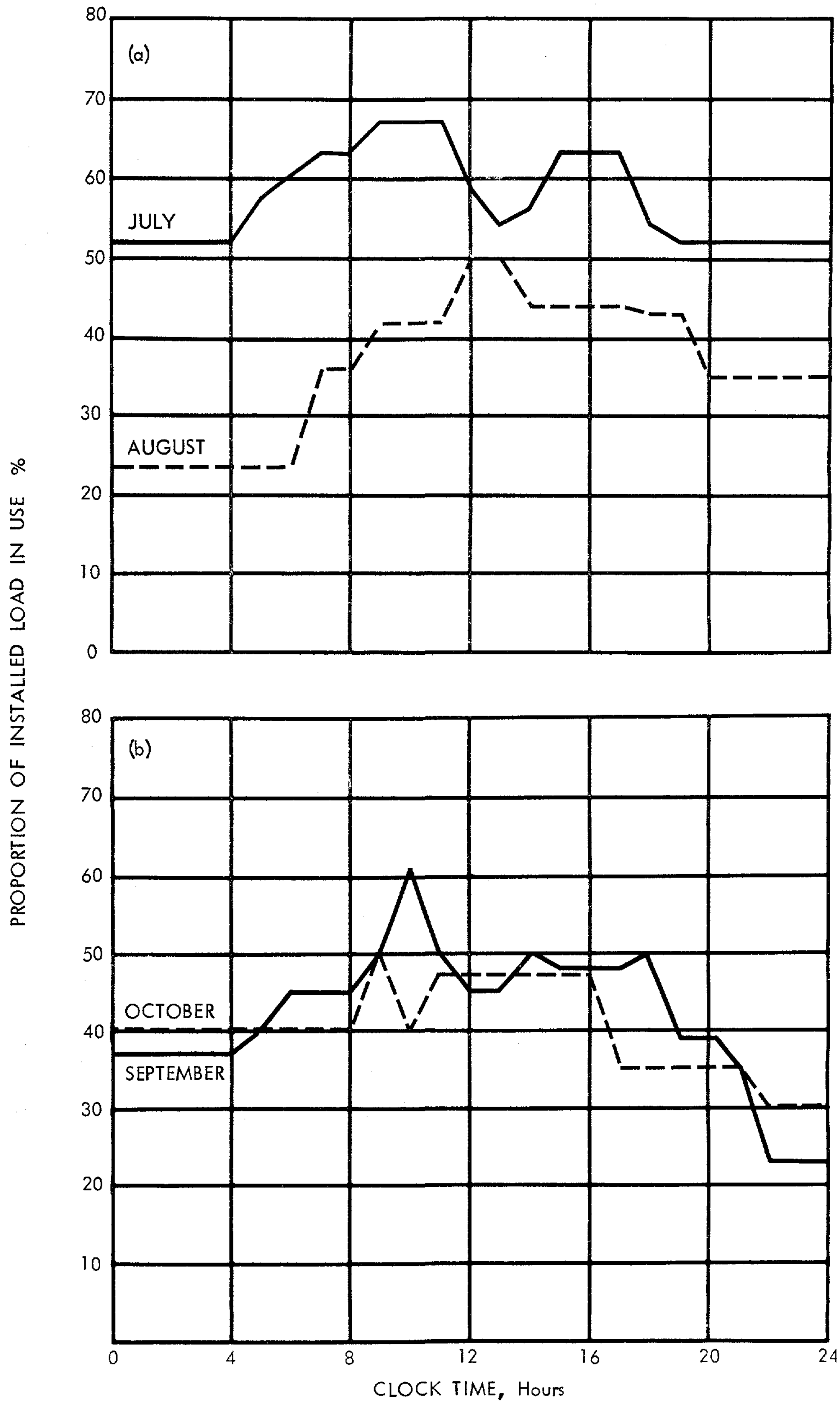

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FIGURE 4.8

WORKING DAY DEMAND CURVES 1969/70

PUBLIC TUBEWELLS

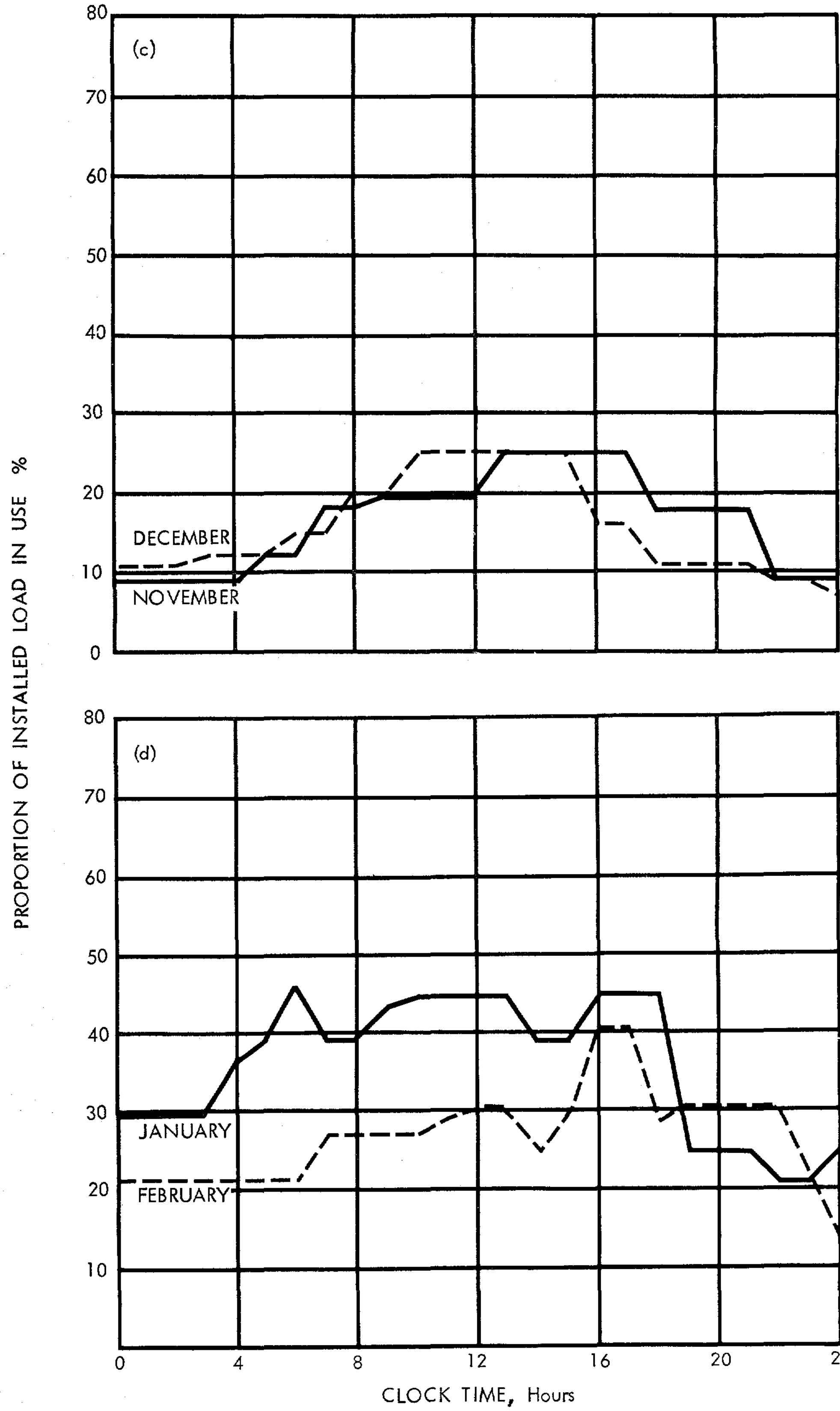

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FIGURE 4.8

WORKING DAY DEMAND CURVES 1969/70

PUBLIC TUBEWELLS

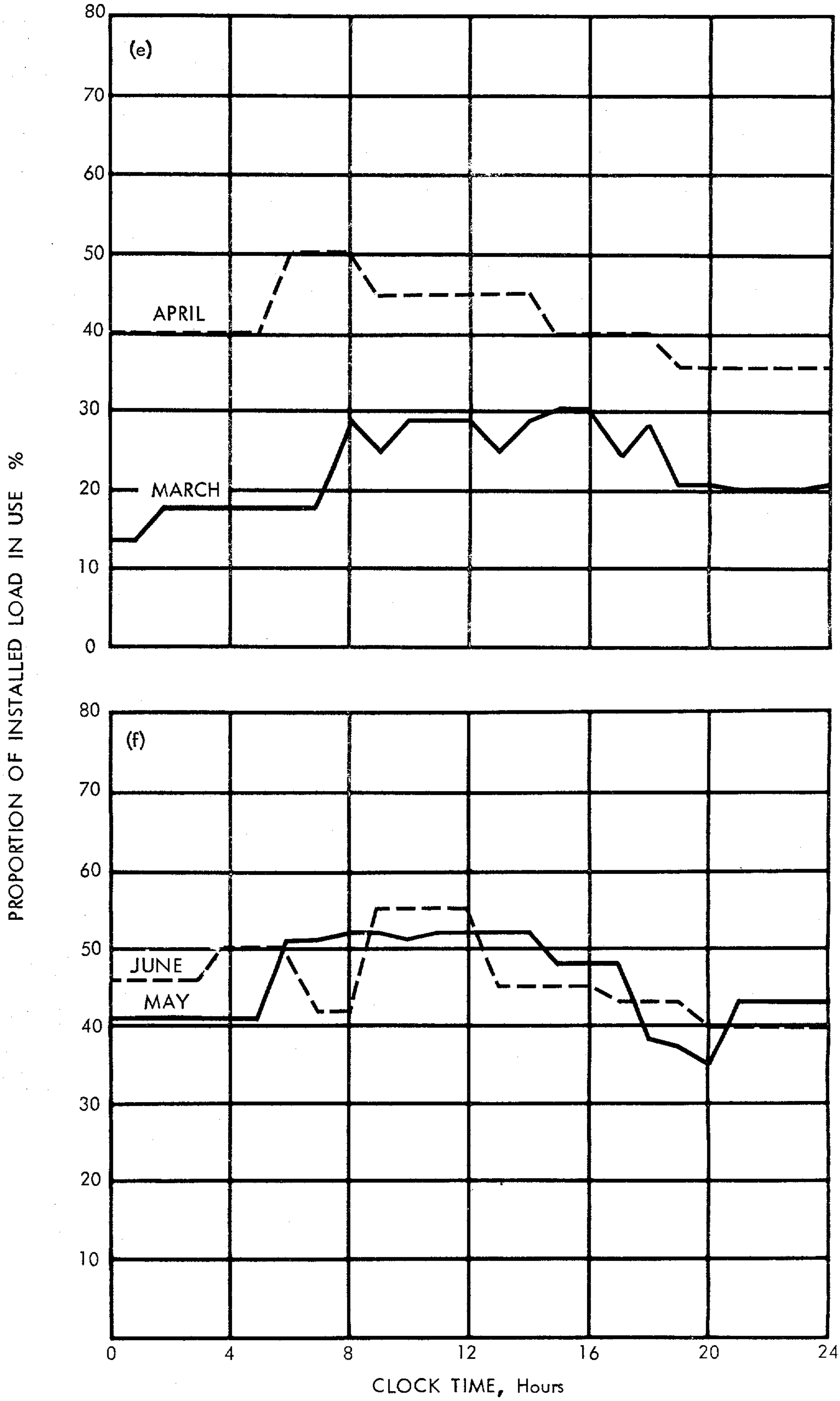

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TABLE 4.5

PUBLIC TUBEWELLS

Estimated Monthly and Annual Consumption

Month	kWh per kW*	Pro-rated to 100%
July	383	13.3
August	249	8.6
September	282	9.8
October	269	9.3
November	114	4.0
December	108	3.7
January	242	8.4
Feburary	181	6.3
March	155	5.4
April	282	9.8
May	309	10.7
June	309	10.7
Annual Total	2,883	100.0

* Hours of use of the installed load.

4.36 Interestingly, views hopefully expressed that farmers made little use of private tubewells through the evening system peak hours and that public tubewells operated a 50% staggered shift by arrangement through those same hours are not supported by Figures 4.7 or 4.8. However, substantially different demand levels are shown for the different months.

4.37 Figure 4.9, Sections (a) to (f), shows the estimated daily demand patterns for industrial consumers with connected loads of under 500 kW (see also Table 4.6). The patterns for March/April/May/June are remarkably similar to British measurements. Most days show much single-shift working and a lunch-time dip. The hours of use of the installed load in Table 4.7 only reach 1,584 in comparison with 2,183 for private and 2,883 for public tubewells, i.e. the small-industry installations were the least intensively used.

TABLE 4.6

ESTIMATED WORKING-DAY DEMAND FACTORS
FOR A MIXTURE OF SMALL (UNDER 70 kW EACH) AND
MEDIUM (70 up to 500 kW EACH) INDUSTRIES

(Based on 11 kV Feeder Data)

Proportion of Installed Load in Use, %

Hour	JULY 1969	AUG. 1969	SEPT. 1969	OCT. 1969	NOV. 1969	DEC. 1969	JAN. 1970	FEB. 1970	MAR. 1970	APR. 1970	MAY 1970	JUNE 1970	Average
01.00	5	12	12	10	18	14	10	10	19	18	16	12	13
02.00	7	12	13	10	18	15	10	10	20	19	16	12	13
03.00	7	12	12	10	14	13	10	10	20	19	16	14	13
04.00	7	12	13	10	14	13	10	10	18	19	15	12	12
05.00	10	12	14	10	12	16	10	10	18	18	15	18	13
06.00	18	12	20	10	12	12	10	10	18	18	22	20	15
07.00	20	20	22	12	24	12	10	10	20	22	25	26	18
08.00	22	25	24	15	33	18	12	12	24	37	30	33	23
09.00	39	25	48	22	33	26	20	22	30	33	32	35	30
10.00	32	22	48	32	30	28	28	20	30	33	32	35	30
11.00	32	37	33	33	30	28	26	20	28	33	39	32	30
12.00	32	22	20	33	30	28	24	20	22	23	32	28	26
13.00	22	20	20	24	22	20	20	14	24	26	32	30	22
14.00	28	30	32	35	24	20	22	19	28	37	32	30	28
15.00	25	20	32	33	20	32	22	19	24	35	35	32	27
16.00	22	24	30	24	18	30	20	18	22	24	28	26	23
17.00	25	25	18	27	20	18	20	18	20	20	26	24	21
18.00	20	22	18	18	20	20	22	14	16	20	22	18	19
19.00	15	10	15	10	22	20	15	12	16	20	20	16	15
20.00	10	12	16	16	24	20	13	10	18	20	20	16	16
21.00	10	12	14	14	18	14	12	10	18	22	18	12	14
22.00	10	12	14	14	16	13	12	10	14	22	18	12	13
23.00	8	12	13	16	15	12	12	10	14	22	16	12	13
24.00	8	12	16	15	17	14	12	10	13	21	18	18	14
Average	18	18	21	18	21	19	15	13	20	24	23	21	19

FIGURE 4.9

WORKING DAY DEMAND CURVES 1969/70

MEDIUM AND SMALL INDUSTRIAL

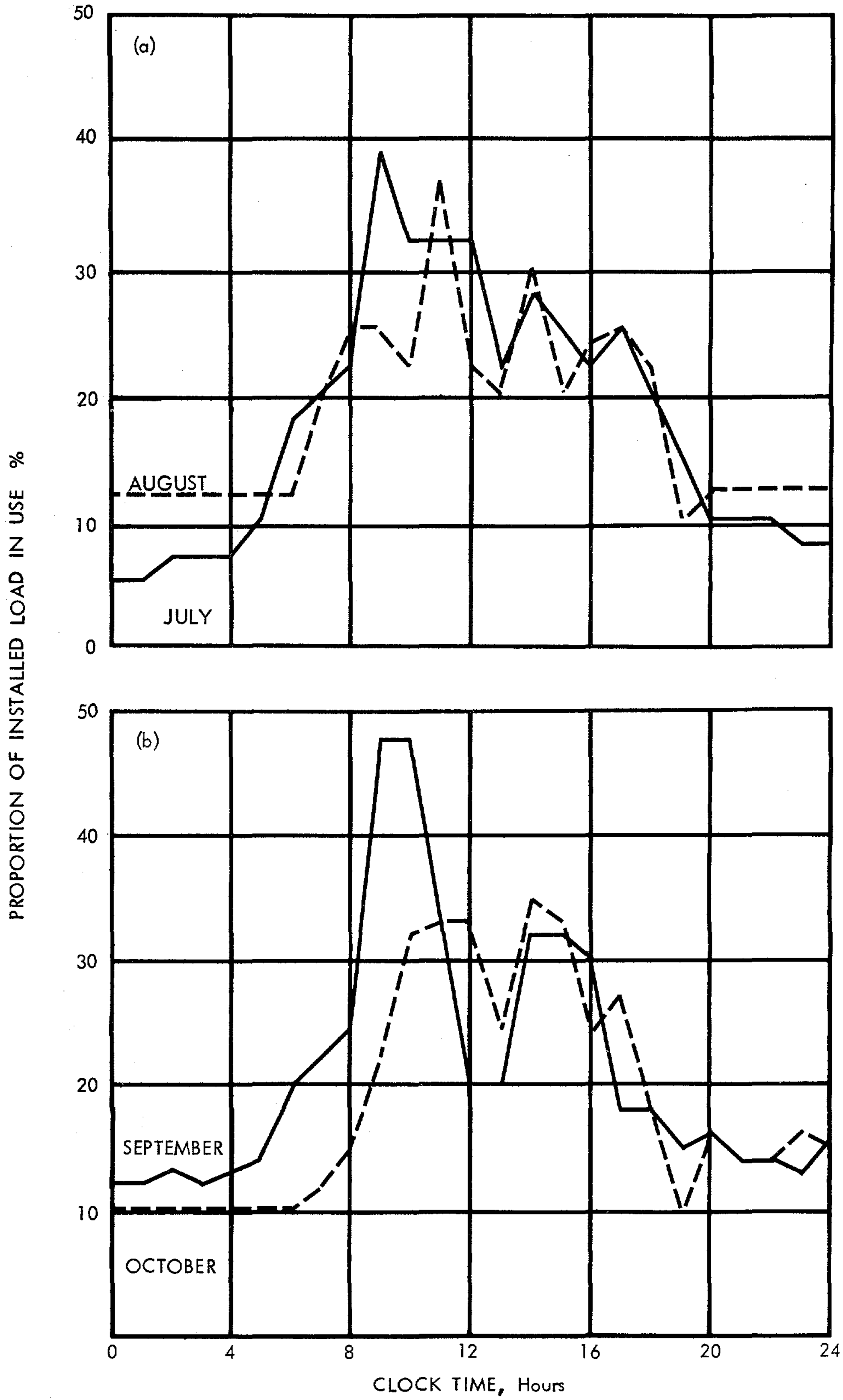

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FIGURE 4.9

WORKING DAY DEMAND CURVES 1969/70

MEDIUM AND SMALL INDUSTRIAL

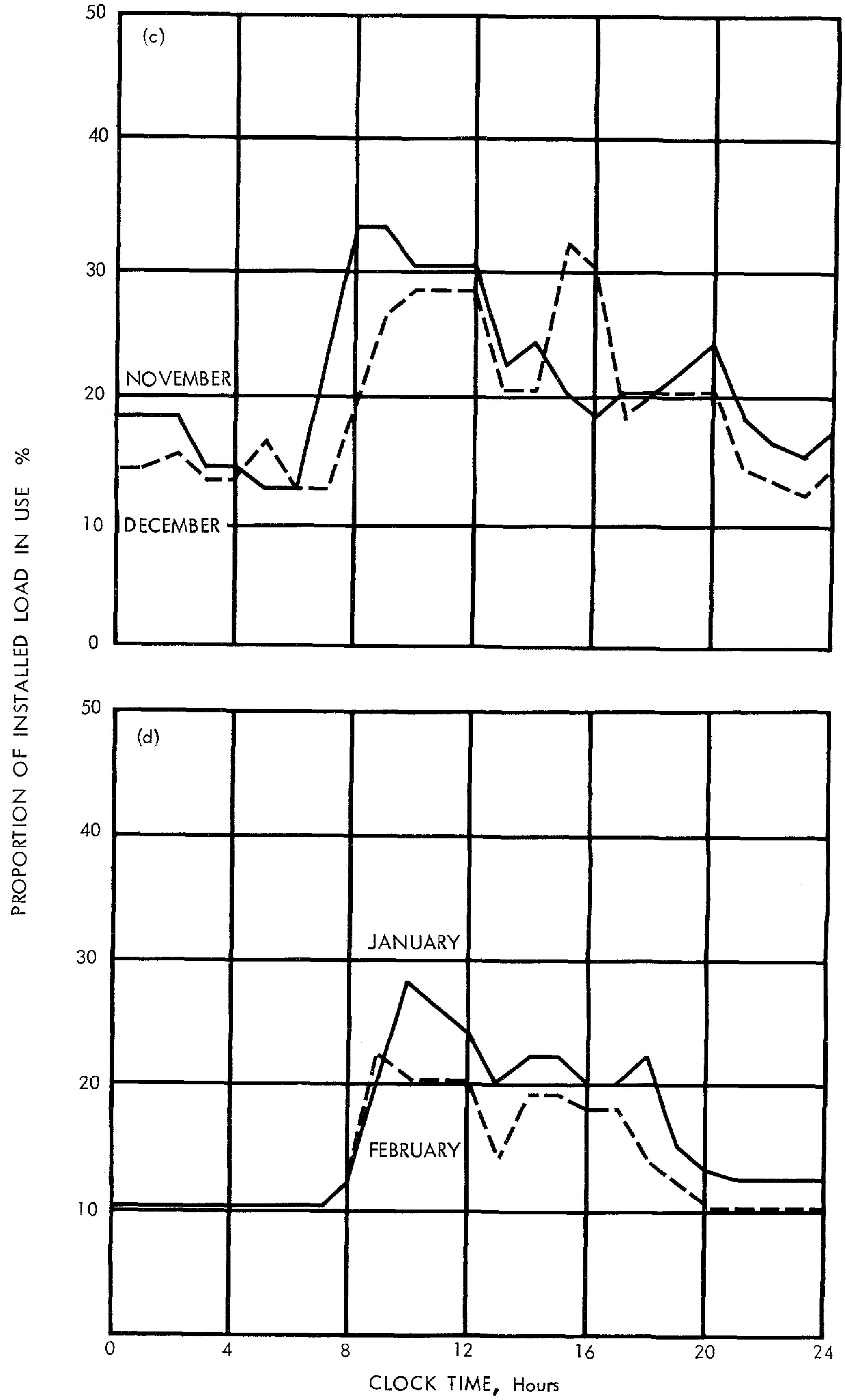

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FIGURE 4.9

WORKING DAY DEMAND CURVES 1969/70

MEDIUM AND SMALL INDUSTRIAL

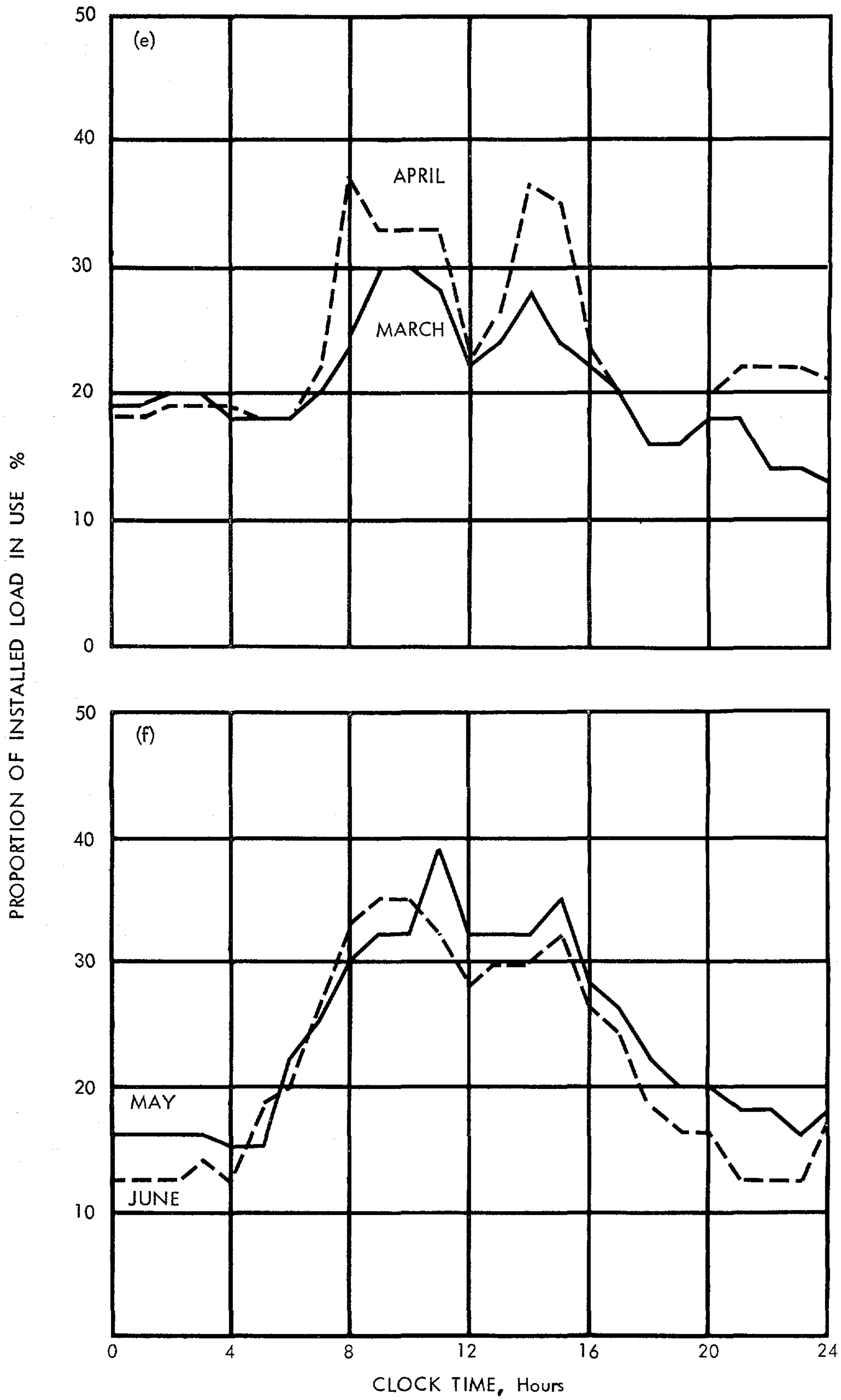

TABLE 4.7

MEDIUM AND SMALL INDUSTRY

Estimated Monthly and Annual Consumption

Month	kWh per kW*	Pro-rated to 100%
July	121	7.6
August	121	7.6
September	144	9.1
October	126	8.0
November	141	9.0
December	127	8.0
January	106	6.7
February	91	5.7
March	138	8.7
April	162	10.2
May	161	10.2
June	146	9.2
Annual Total	1,584	100.0

* Hours of use of the installed load.

4.38 Attempts to obtain similar data for large industrial consumers were thwarted by the feeder data being subject to tampering, but interviews with industrialists revealed much three-shift working. Very flat demand patterns are therefore expected.

4.39 Residential demand data were not obtained and can only be obtained by this (feeder) technique from clearly atypical areas such as railway cantonments and wealthy suburbs. Elsewhere the residential demand does not dominate but rather is itself dominated by commercial, industrial and tubewell loads. While the residential load contributes only 10% to the total kWh sales, owing to the expected lower annual load factor 1/ of this group, the contribution made to system peak might reach 15%. However this demand component is set up by 0.8 million consumers so that, apart from price variation, the residential load seemed to be a most unlikely candidate for load control.

4.40 From this study of demand data and from a study of WAPDA's tariffs and commercial practices, the most likely candidates, in principle, for some measure of load control, perhaps by differential pricing, were:

1/ Effective at the time of system peak, supposing the peak occurs on a winter evening, i.e. when the lighting load is high.

a. private tubewells
b. public tubewells, and
c. large industry

Table 4.8 shows how the private and public tubewell estimated demand data given earlier were blown up to give demand contributions to system demand for the total WAPDA system. The scale factors, i.e. the extent of agricultural pumping, were taken from the recent Indus Basin Review Mission, Report by Consultants (Gibb & Partners, International Land Development, Hunting Technical Services) June 1970.

TABLE 4.8

GENERATION REQUIREMENTS
TO MEET TUBEWELL LOADS, 1970/71
(WEST PAKISTAN)

Month	Private Tubewells		Public Tubewells		Total Tubewells
	No.	MW	No.	MW	MW
July	36,450	281	5,468	104	385
August	36,794	330	5,573	74	404
September	37,138	267	5,678	82	349
October	37,482	200	5,783	72	272
November	37,826	81	5,888	43	124
December	38,170	70	5,993	27	97
January	38,514	67	6,098	72	139
February	38,858	19	6,203	67	86
March	39,202	136	6,308	51	187
April	39,546	68	6,413	81	149
May	39,890	68	6,518	89	157
June	40,234	289	6,623	97	386
Yearly Average	38,342	156	6,046	72	228

Notes: (1) The numbers of wells are taken from the Indus Basin Review Mission, Report by Consultants, assuming that 45% of private tubewells are electrified.

(2) Generation requirements (excluding provision of spare capacity) are based on feeder data averaged over the period 16.30 to 21.00 hours.

(3) Allowances have been made for the auxiliary consumption at the power stations and for the losses in transmission and distribution. Insofar as the demand data were obtained from 11 kV feeders, it does not seem appropriate to make any allowance for pilferage.

4.41 Owing to the small demand estimate obtained for private tubewells in February, the load (strictly generating capacity to meet load) available for manipulation is then fairly small, i.e. 86 MW in total, but for the critical water-shortage months of March, April and May, the total tubewell load is around 150 MW. This is about one-sixth of the total load for all purposes (as here defined). On the assumptiors that pumping has spare capacity and that a deferment or advancement of a few hours is of little or no consequence to crops, the pumping load has been singled out as the most promising candidate for load control. Others, of course, have formed this view previously. However, the daily and seasonal demand patterns given here, even though they are subject to substantial margins of error, enable a fairly clear view to be formed of the possible impact on the system of load control and differential pricing applied to pumping.

5. THE SUPPLY OF ELECTRICITY

West Pakistan Electricity Supply Overview

5.01 The major sources of electricity supply in West Pakistan are WAPDA (Water and Power Development Authority) and KESC (Karachi Electric Supply Corporation Ltd.). WAPDA operate four supply systems which are at present not interconnected: (1) the Northern Area Grid which is by far the largest and contains all of the hydroelectric capacity, (2) the Upper Sind with its thermal electric capacity at Sukkur in operation and at Gudu under construction, (3) the Lower Sind with thermal electric capacity in Hyderabad, and (4) a small separate 15 MW coal-based system in Quetta. KESC operates a system in the Karachi area, and this system is now interconnected with the WAPDA Lower Sind system. For more detail, see the map, Figure 5.1.

5.02 Total generating capacity in West Pakistan as of 1970 is around 1,900 MW. Of this, 10% is private self-generation capacity. There are about 1.5 million registered electricity customers, two-thirds of them WAPDA's, and per capita generation in West Pakistan is around 9 kWh per month.

5.03 Much of the discussion and analysis of this chapter is centered on WAPDA. And within WAPDA it largely concentrates on the problems of the Northern Grid which now accounts for about 90% of WAPDA generation. The computations do make allowance for the planned interconnections of the Northern Grid with the Upper Sind and the Lower Sind - Karachi systems.

5.04 In the fiscal year ending June 30, 1970, the WAPDA Northern Grid generated over 4,600 million kWh. Of this total about 2,900 million kWh were generated in the various hydroelectric stations. One of the critical features of the system is the variability of hydroelectric capability. This can be seen in part by the monthly variations of hydroelectric energy produced. During the fiscal year just ended, hydroelectric supply varied from a low of 192.8 million kWh in February 1970 to a high of 274.1 million kWh in June 1970. Table 5.1 gives a breakdown of the total generation for the year. Actually these data do not fully illustrate the seasonality of hydroelectric energy in this WAPDA system. The reasons for this will become clear from the discussion below.

Figure 5.1

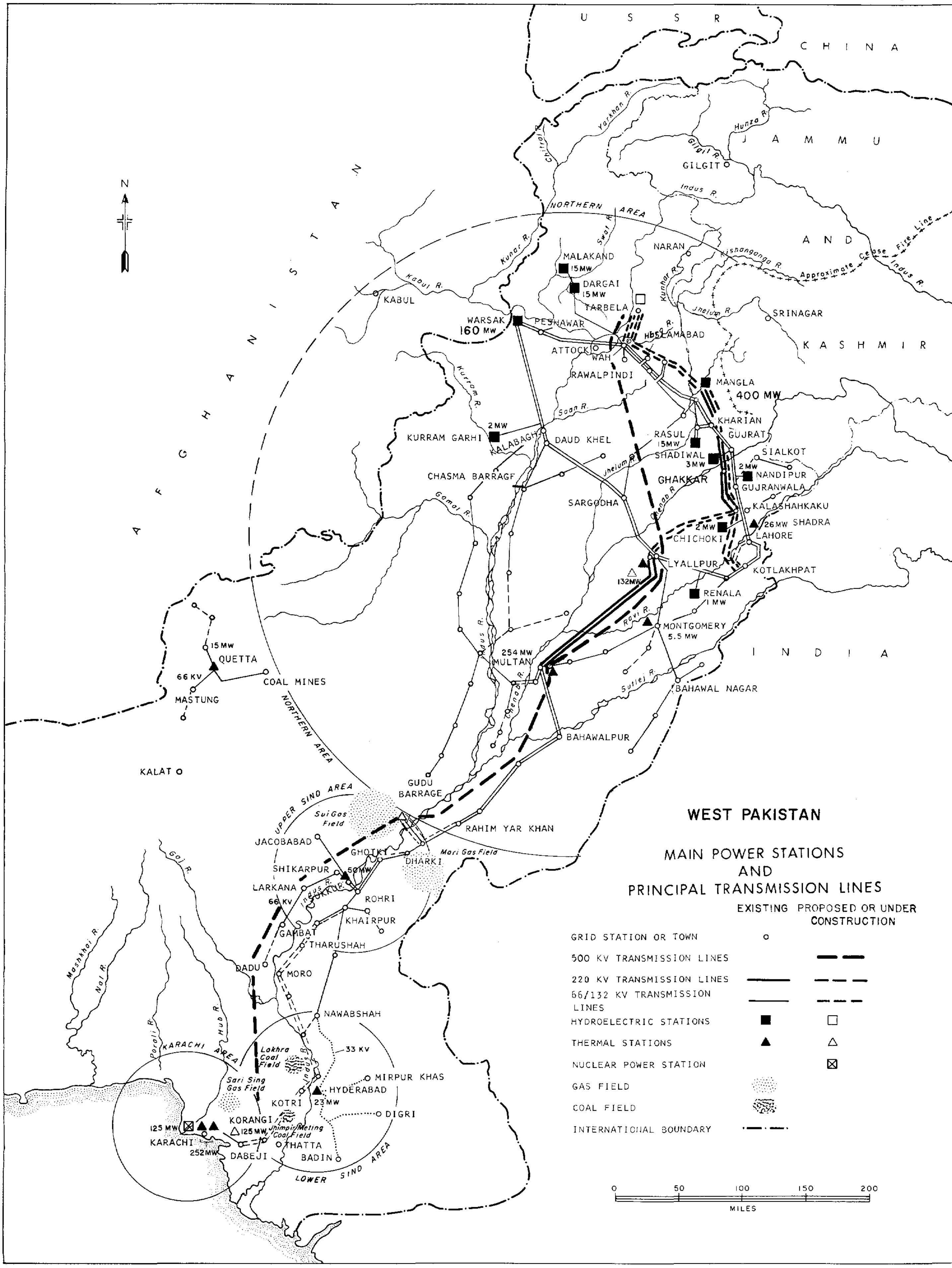
WEST PAKISTAN
MAIN POWER STATIONS
AND
PRINCIPAL TRANSMISSION LINES
EXISTING
PROPOSED OR UNDER CONSTRUCTION
GRID STATION OR TOWN
500 KV TRANSMISSION LINES
220 KV TRANSMISSION LINES
66/132 KV TRANSMISSION LINES
HYDROELECTRIC STATIONS
THERMAL STATIONS
NUCLEAR POWER STATION
GAS FIELD
COAL FIELD
INTERNATIONAL BOUNDARY
0 50 100 150 200
MILES
U S S R
C H I N A
J A M M U
A N D
K A S H M I R
I N D I A
A F G H A N I S T A N
Approximate Cease Fire Line
NORTHERN AREA
UPPER SIND AREA
LOWER SIND AREA
KARACHI AREA
GILGIT
NARAN
SRINAGAR
KABUL
MALAKAND 15 MW
DARGAI 15 MW
TARBELA
WARSAK 160 MW
PESHAWAR
ISLAMABAD
ATTOCK
WAH
RAWALPINDI
MANGLA 400 MW
KHARIAN
GUJRAT
SIALKOT
NANDIPUR 2 MW
GUJRANWALA
RASUL 15 MW
SHADIWAL 3 MW
GHAKKAR
KURRAM GARHI 2 MW
KALABAGH
DAUD KHEL
CHASMA BARRAGE
SARGODHA
KALASHAHKAKU
CHICHOKI 2 MW
SHADRA 26 MW
LAHORE
LYALLPUR 132 MW
KOTLAKHPAT
RENALA 1 MW
MONTGOMERY 5.5 MW
MULTAN 254 MW
BAHAWAL NAGAR
BAHAWALPUR
QUETTA 15 MW
66 KV
MASTUNG
COAL MINES
KALAT
GUDU BARRAGE
Sui Gas Field
RAHIM YAR KHAN
JACOBABAD
GHOTKI
DHARKI
Mari Gas Field
SHIKARPUR 50 MW
LARKANA 66 KV
SUKKUR
ROHRI
KHAIRPUR
GAMBAT
THARUSHAH
DADU
MORO
NAWABSHAH
33 KV
Lakhra Coal Field
MIRPUR KHAS
HYDERABAD 23 MW
KOTRI
DIGRI
Sari Sing Gas Field
KORANGI 125 MW
Jhimpir Meting Coal Field
KARACHI 125 MW 252 MW
DABEJI
THATTA
BADIN
Yarkhan R.
Chitral R.
Hunza R.
Gilgit R.
Indus R.
Swat R.
Kunar R.
Kabul R.
Kishanganga R.
Kunhar R.
Jhelum R.
Kurram R.
Soan R.
Gomal R.
Chenab R.
Ravi R.
Sutlej R.
Gaj R.
Mashkhai R.
Nal R.
Porali R.
Hub R.

TABLE 5.1

COMPOSITION OF WAPDA NORTHERN GRID GENERATION
July 1, 1969 - June 30, 1970

	kWh (millions)				
Month	Hydro-electric	Steam	Gas Turbines	Diesel	Total*
July '69	240.4	141.7	5.8	0.5	388.3
Aug. '69	240.4	135.5	9.4	0.3	385.6
Sept.'69	269.3	111.6	5.7	0.5	387.1
Oct. '69	268.6	118.6	10.7	0.2	398.0
Nov. '69	241.5	112.0	0.1	0	353.7
Dec. '69	237.3	141.5	1.4	0.2	380.0
Jan. '70	241.0	163.2	7.9	0.2	412.4
Feb. '70	192.8	147.4	7.9	0.2	348.4
Mar. '70	200.4	161.2	3.1	0.1	364.7
Apr. '70	239.6	136.1	7.1	0.2	383.0
May '70	268.3	134.7	4.0	0.1	406.0
June '70	274.1	122.9	4.4	0.4	401.8
	2,913.7	1,626.4	67.5	2.9	4,609.0

* Detail may not add due to rounding errors.
Source: WAPDA Daily Load Registers for last day of the month.

Hydroelectric Supply

5.05 At present hydroelectric energy is provided by eight relatively small installations on irrigation canals whose collective capabilities are estimated to vary in a normal water year from 48 MW in December, January and February to 88 MW from May through October. Actually during the 1969-70 year, the capabilities did not vary quite this widely for various reasons: neither the troughs were as low, nor the peaks as high. In addition there is Warsak whose capability is estimated to range during the average water year from 100 to 160 MW, with the upper end of the range applicable from April through September, and the lower end of the range applicable for the rest of the year. For all eight small canal plants combined the energy available during each month is estimated to vary over the year somewhat less than the capabilities, whereas for Warsak the relative energy variations month to month are greater than the relative capability variations. Finally, there is Mangla reservoir, one of the major installations of the Indus Basin project. As of mid-1970, four generating units had been installed. With the reservoir release schedules that are assumed for an average water year, the capability of each unit is estimated to vary from 58 MW in March-April to 115 MW from July through November. Actual loads on Mangla have been much less than the maximum capabilities available. Various factors, including transmission line capacity shortages that are about to be rectified, have contributed to the under-utilizations of potential generating capacity at Mangla.

Thermal Electric Supply

5.06 The major thermal installations on the Northern Grid are the Multan steam station rated at 240 MW, the Lyallpur steam station rated at 132 MW, and the Lahore gas turbine station (Shahdara) with six units rated at a total of about 76 MW. Although all of these installations are quite new, there have been serious maintenance problems. For example, one 65 MW unit at Multan was out of operation from July 1967 to May 1970. Number 1 and 2 units at Shahdara (22 MW) were taken out of service in August 1969 with the announced expectation that maintenance would be completed April 30, 1970. By April 30, this date had been advanced to May 31, by May 31, it had been advanced to June 30, and by June 30, no expected date of completion at all was listed on the Daily Load Reports. It was reported that spare parts were not available.

5.07 Even routine maintenance requirements raise difficulties. The boilers at the conventional thermal stations are estimated to require two weeks per unit per year, and every two years 6 to 8 weeks is thought to be required for overhaul. It is said that because of the extreme high summer temperatures thermal station boilers cannot be maintained during the summer months. The Shahdara gas turbines should be serviced every 250 starts or 8,000 hours, and this should normally require 4 to 6 weeks. It might be noted that the Mangla station hydro units are thought to require one month per year per unit for proper maintenance. However, this might be speeded up considerably if maintenance work were undertaken around the clock rather than on 8-hour shifts.

Dispatching

5.08 The hour-to-hour dispatching for economy is in practice made difficult by special circumstances. Some of these, like the restriction on rates of discharge at Warsak, may be justified, although a more complete evaluation should be undertaken of the social cost of down-stream flooding and of the measures to prevent or to reduce resulting damage. Other special circumstances may be less justified. For example, there is very serious question on whether it is, in fact, necessary for technical reasons to generate as much power at the Multan and Lyallpur thermal stations during hours of low demand. Economy requires that Mangla should generate electricity with as much of the water released for irrigation purposes as possible. As long as water is released during the day that could be, but is not used to drive the turbines, further reduction of output in the fuel-using thermal stations and corresponding increases of output at Mangla are desirable. In fact, there seems to be a reluctance on the part of WAPDA dispatchers to order reductions of thermal station generation to minimum levels. The technical possibilities for reducing the loads on Multan and Lyallpur thermal stations during off-peak hours so as to achieve maximum economy seem not to have been fully explored.

Demand vs. Supply

5.09 The daily and annual load curves observed on the WAPDA Northern Grid in recent years are not a correct reflection of the demands on the system at prevailing prices. The reason for this is that numerous non-price rationing techniques are employed. The observed load curves are in some sense records of demand or supply, whichever is greater. However, to the extent that physical rationing shifts demands from one period of time to another or to the extent that cutting-off supply during one interval reduces demand during another interval also, this characterization of observed load curves also is not entirely correct. During 1969-70, 11 kV feeders have been shut down to prevent overloads on transformers, there have been moratoria on new connections, there have been agreements for new connections provided the customer agreed to take his load only during off-peak hours, and there have been other rationing devices. Physical rationing of electricity is more fully discussed in Chapter 7. The point that needs to be emphasized here is that observed load curves over the past years do not reflect the consequences of rationing through the use of the price mechanism. Daily load factors which sometimes exceed 80% and average perhaps between 75% and 80% are not the sort of load factors that can be considered the consequence of planning the efficient allocation of resources. They are the consequences of numerous *ad hoc* measures designed "to get by" while demand exceeds supply.

5.10 The forecasts of demand and supply used in this chapter do make more "normal" assumptions. Indeed, the computer calculations reported on later may go too far in the opposite direction by ignoring some of the dispatching problems referred to above. On the demand side the assumption is that the present price structure and projected plans for transmission, distribution and new connections are consistent with the load and energy forecast of Harza International (Harza), the general consultants to WAPDA. These forecasts by months and regions to 1985 are given in Annex 7, Tables B-3 and B-4. 1/ Some idea of the structure of the forecast is obtained from Figures 5.2 and 5.3. Figure 5.2 shows the relationship between monthly energy and load forecasts for 1969-70 and Figure 5.3 shows the growth of demand by months for the Northern Market taken by itself on a ratio scale for the first 11 years. Such forecasts are provided by Harza also for the Upper Sind, Lower Sind, and Karachi. They represent gross generation requirements. The forecasted loads by regions have been accepted for the

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1/ Data for months preceding April 1970 are said to be actual data; however, the monthly energy figures cannot be reconciled with those reported in Table 5.1 of this Chapter, which were copied directly from the Daily Load Register.

purposes of this chapter; and where necessary they have been extrapolated for additional years beyond 1985 at the same constant percentage rates as those used in the last years of the Harza forecasts. 1/

5.11 A comparison of actual loads with projected loads is provided by Figure 5.4 and Figure 5.5. The first shows monthly average of peaks for workdays by months during 1969-70. The second shows peak loads by months forecast by Harza. One important characteristic to note is that there are no strong seasonal components in actual or forecast total demands. For later years the seasonality in forecast total demands becomes if anything less pronounced. For example, the lowest monthly peak for the Northern Grid forecast for 1970-71 (870 MW in April 1971) is just about equal to the highest monthly peak load forecast for 1969-80 (878 MW in June 1970). For the projected combined West Pakistan system the story is much the same. Thus, the April 1977 trough (2,330 MW) of the 1976-77 year is just about the same as the June 1976 peak (2,336 MW) of the previous fiscal year.

5.12 The Harza supply forecasts of load consist of two parts. First, there is assumed a plant expansion and interconnection program. Second, there is assumed a water availability schedule for each hydroelectric plant determining its capability in MW. These Harza supply projections are summarized in the computer print-outs Tables C-4 and C-5 of Annex 7. It should be observed that the print-outs postulate interconnection of the Northern Grid with Upper Sind as of mid-1973, and the further interconnection of these combined grids with Karachi and Lower Sind as of mid-1975. Included are projections for plant additions for the developing Northern Grid -- almost all of West Pakistan -- to mid-1986.

5.13 The monthly estimates of capability projections for each plant make no direct allowance for maintenance requirements. 2/ They are based on the thermal and hydraulic characteristics of existing and projected plants, and, for the hydro plants, on assumed average run-off conditions

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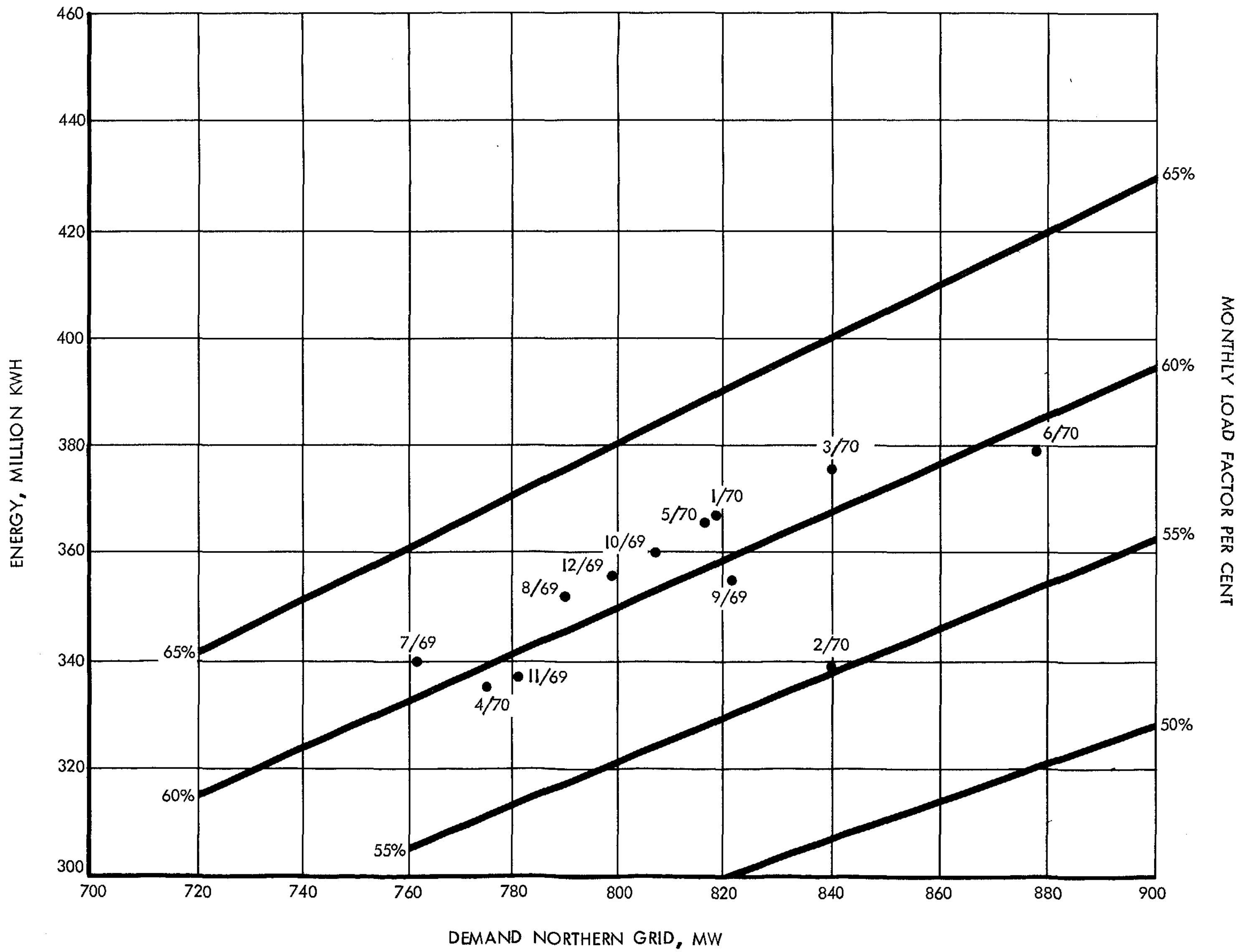
1/ Some of the later work in this chapter utilizes forecasts of monthly load factors and also monthly values of minimum loads. For these magnitutes, data used earlier in the World Bank's computer simulations of the West Pakistan power system were used. The energy forecasts are those implied by these load factors rather than those provided by Harza.

2/ To mid-1975 there is a computation of "firm capability" for each month, which is the estimated actual capability for that month in an average water year less the capability of the largest unit. From mid-1975 onwards "firm capability" is calculated by subtracting from actual capability the largest hydro and the largest thermal unit. This type of "rule-of-thumb" allowance for unscheduled outages is sometimes used for power systems in developed countries. It probably is not a good method for determining reserves in developed countries and a worse method for underdeveloped countries.

Figure 5.2

RELATIONSHIP BETWEEN ENERGY AND LOAD FORECASTS
1969-70



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FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH

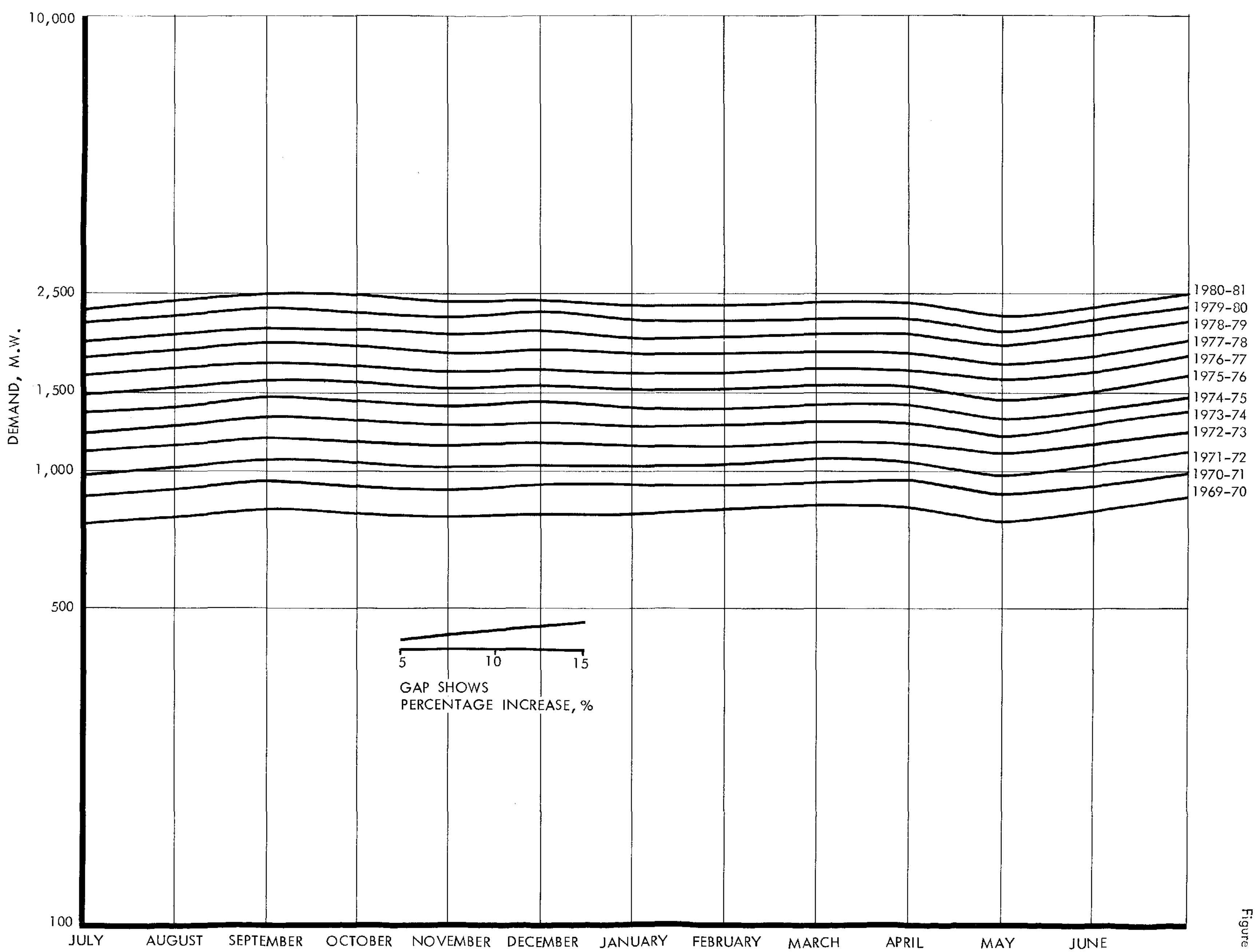

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Figure 5.3

MONTHLY PEAK LOAD NORTHERN GRID 1969-70

(MEAN OF DAILY MAXIMUM FOR WORKING DAYS)

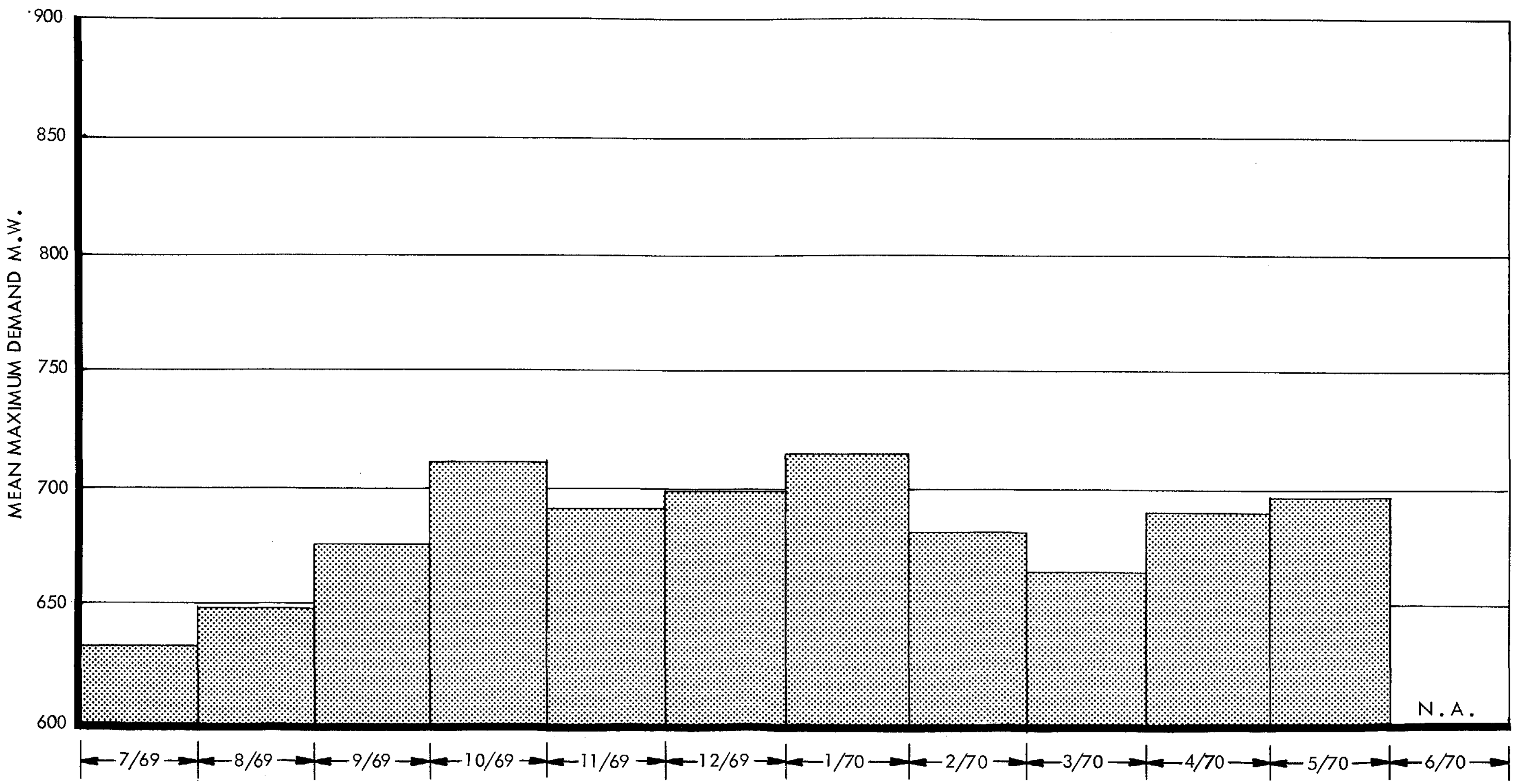

Figure 5.4

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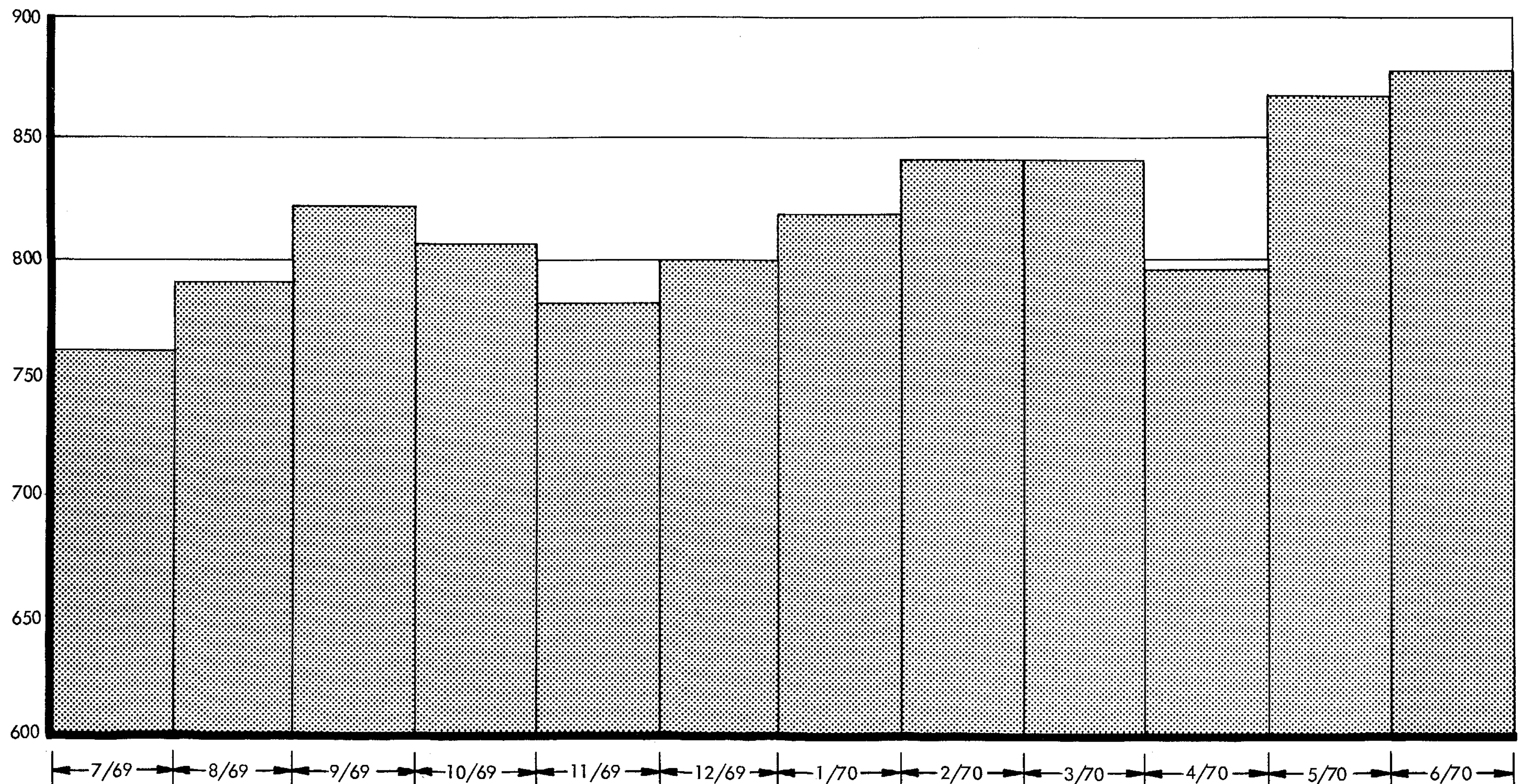
FORECAST OF MONTHLY PEAK LOAD NORTHERN GRID



IBRD-5416

Figure 5.5

and on the water-release schedules for each month based on the storage possibilities and irrigation plans. The capabilities of Mangla, Tarbela and perhaps later of Kalabagh would differ, on the one hand, if irrigation authorities were to adopt different seasonal time patterns for reservoir releases or, on the other hand, if more or less water were to be available because of better or worse water years, given the projected water-release patterns.

5.14 For purposes of some of the analyses below, the Harza projections on the supply side will be somewhat modified. The interconnection and plant expansion schedules will be altered, particularly in the early years, so as to take account of the delays and changes that now appear likely. Indeed, for the period 1970-75 the supply program outlined in the excerpt from the Draft Fourth Five Year Plan for the Power Sector (reproduced as Annex 3) has been the guide for the computer analyses in this Chapter. Table 5.2 gives the expansion plans that were used in the computer simulation. 1/

5.15 The capabilities of the hydroelectric plants used in the analyses of this chapter are those given by Harza. 2/ The capability data are supplemented by data on availability of hydroelectric energy for each month of a "normal" year from the earlier World Bank simulations of the West Pakistan power system and the Lieftinck study. The rule curves used in the Harza projections, particularly for the now-existing Mangla reservoir, do not appear to give much priority to the needs of the electric power sector. This is perhaps the way it should be, yet joint optimization of power and agricultural benefits might yield somewhat different capabilities for each month at Mangla and for other reservoirs also. Nevertheless, the view taken in this Chapter is that monthly irrigation requirements are given and, as will be seen below, monthly electric energy required for irrigation pumping (tubewells) is also given. 3/ This should not be interpreted as an endorsement of these "rule curves" or of the techniques by which reservoir discharge programs and irrigation requirements are determined. On the contrary, it is recommended that the consequences of alternative irrigation programs continue to be investigated and evaluated in terms of both their agricultural and their power benefits.

1/ The entries give annual capacity data for each year. Zero shows plant not completed. For detailed explanation of the model and notation see Pieter Lieftinck, et al., Water and Power Resources of West Pakistan, Vol. III, especially pp. 357-384.

2/ The capabilities of units at Mangla used for computer analyses are the more pessimistic ones given in Annex 7, Table C-4, rather than those in Table C-5. The hope that at high water (e.g., September) a Mangla unit could generate 131 MW has apparently not been borne out by experience. Thus, a maximum of 115 MW is assumed.

3/ See Annex 8 for the details on tubewell demand estimation.

Seasonal System Stresses

5.16 Although total peak demand for power is not expected to be subject to pronounced seasonal patterns under prevailing tariff and other electricity rationing policies, there are nevertheless sharply pronounced seasonal stresses on the system which cause costs for energy at certain times to be high and which require additional investment if the load is to be rationed according to the patterns now predicted.

5.17 The seasonal stresses arise largely from the seasonality of water requirements for agriculture and associated fluctuations in heads. The timing of the extremely important agricultural uses of water causes, on the one hand, a pronounced seasonal pattern in the capabilities of the hydroelectric installations. On the other hand, it also causes a high degree of seasonality in water pumping loads by private tubewell and public tubewell operators.

5.18 The seasonal stresses in power resulting from the water release patterns are illustrated by Figures 5.6 through 5.13. In these diagrams the projected demands for the Northern Grid (as now in existence) and for the Northern Grid - Upper Sind interconnection and the Northern Grid-Sind-Karachi interconnections (envisaged for the future) have had subtracted from them the Harza projected capabilities of the hydroelectric plants. Thus, the residuals plotted in each of the graphs show the total load that must be met by supplementary thermal electric capacity.

5.19 As the system is projected to grow in the 1970's with heavy emphasis on the hydro plants at Mangla and Tarbela, the seasonality of loads to be met by thermal plants becomes more pronounced. For example, March 1973 calls for 750 MW thermal capability as against about 300 MW thermal capability in the preceding August (Figure 5.9). For the enlarged Northern Grid the following fiscal year (Figure 5.10) a required March thermal capability peak of 715 MW is paired with a 335 MW trough in the previous July. For the combined West Pakistan Grid in 1980-81 as projected by Harza, the thermal electric capabilities required go from peaks in excess of 1,600 MW during April and May 1981 to troughs averaging less than 300 MW in August, September and October of 1980. Similar diagrams could also be constructed to illustrate the variability of the energy required of thermal plants, giving much the same sort of picture.

5.20 These interpretations of the diagrams need to be qualified. First, it is assumed throughout that there are no transmission constraints. In such a large system with its hydroelectric production concentrated in the North, considerable thermal production may be required nearer the centers of consumption for purposes of network stability and similar technical considerations. Second, no allowance is made for maintenance of either thermal or hydroelectric capacity. However, since the severe summer climate is said to create difficulties for the servicing of thermal electric units, the seasonal fluctuations of demand are not likely to be reduced after allowance is made for maintenance. Third, these projections are based on "average water conditions". Non-average water conditions are

TABLE 5.2

WEST PAKISTAN INTEGRATED POWER SYSTEM - ALTERNATIVE A

STRATEGY LGK-A

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
MUL S	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.	240.
LYA S	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.
MUL GT	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.
LYA D	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.
LAH GT	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.	84.
KARB S	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.	30.
KARBXS	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.	66.
KARELS	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.	5.
KAR DF	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.
KOR S	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.	132.
KORC S	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.
HYDO S	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.	15.
HYDN S	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.	23.
HYD GT	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.	6.
KOT GT	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.
SUK S	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.
GUDU1S	-0.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.
GUDU2S	-0.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.
GUDU3S	0.	-0.	-0.	-0.	-0.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.
GUDU4S	0.	0.	0.	-0.	-0.	-0.	-0.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.
GUDU5S	0.	0.	0.	0.	0.	-0.	-0.	-0.	-0.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.
GUD 9S	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	200.	200.	200.
GUD10S	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	200.	200.
GUD11S	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	200.
KAR N	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.
KAR 3N	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	750.	750.	750.
LYA4 S	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	200.	200.	200.	200.
CANAL	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.	88.
WARSAK	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.	160.
MAN HA	320.	480.	480.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.	640.
TAR HA	-0.	-0.	-0.	-0.	-0.	292.	438.	438.	584.	730.	876.	876.	876.	876.	876.	876.	876.	876.	876.	876.
KALABA	-0.	-0.	-0.	-0.	-0.	-0.	-0.	-0.	-0.	-0.	250.	500.	750.	1000.	1500.	1750.	2000.	2000.	2000.	2000.
500KVH LINK 1	0.	220.	220.	220.	800.	800.	800.	800.	800.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.
500KVH LINK 2	0.	0.	0.	0.	0.	940.	940.	940.	940.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.
500KVH LINK 3	0.	0.	0.	0.	940.	940.	940.	940.	940.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.	1880.

FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY
NORTHERN GRID 1969-70

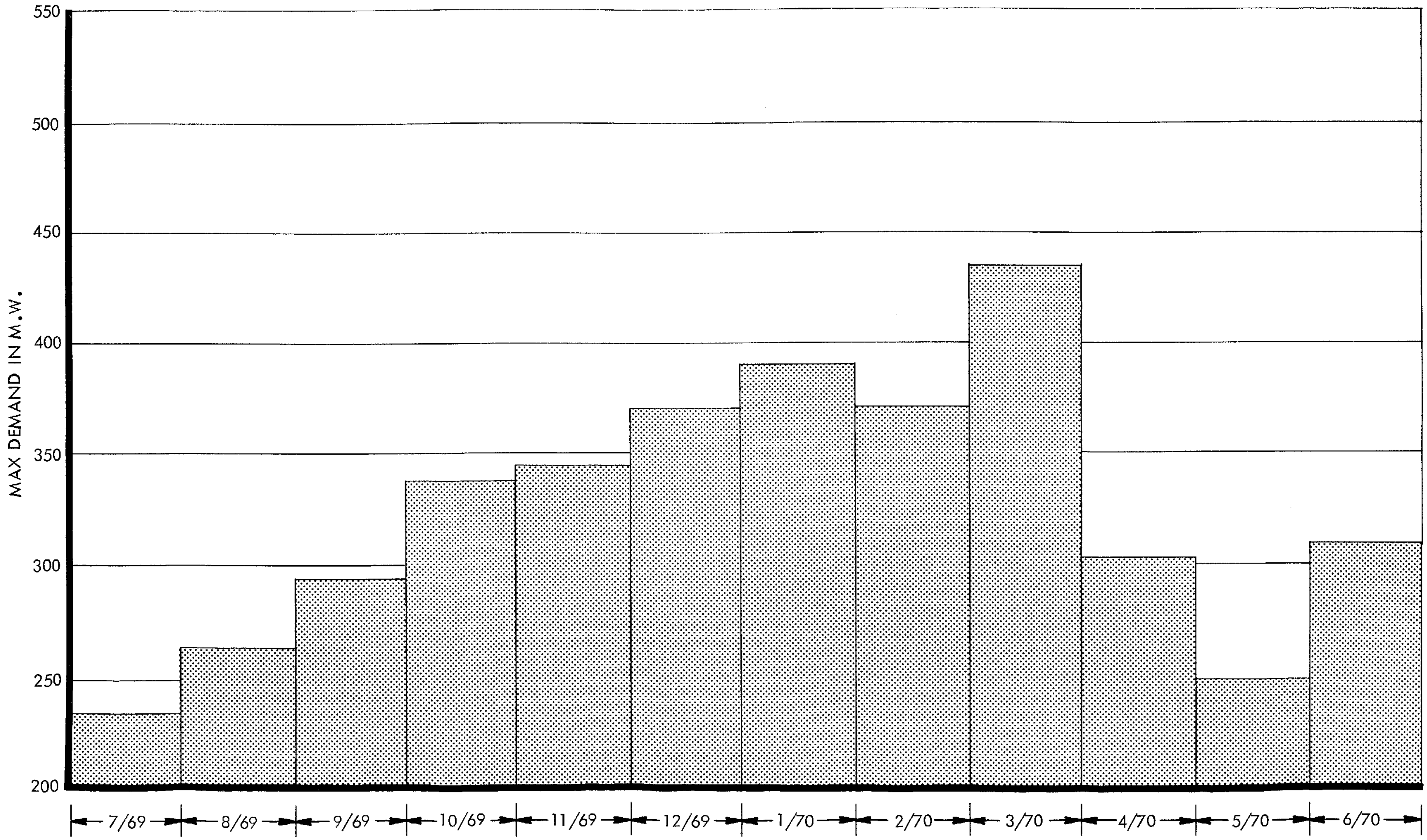


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Figure 5.6

Figure 5.7

FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY
NORTHERN GRID 1970-71

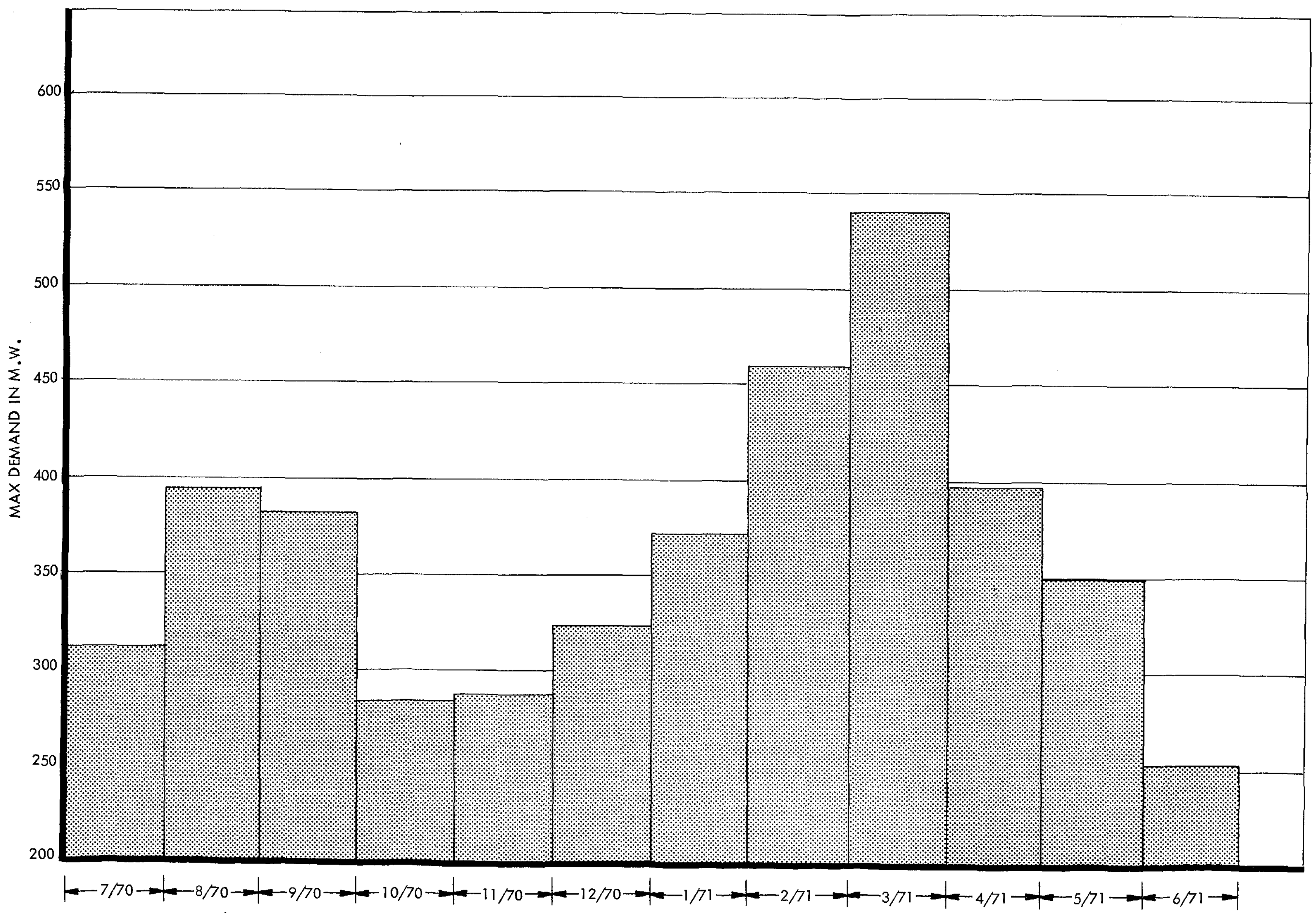

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Figure 5.8

FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY
WEST PAKISTAN NORTHERN GRID 1971-72

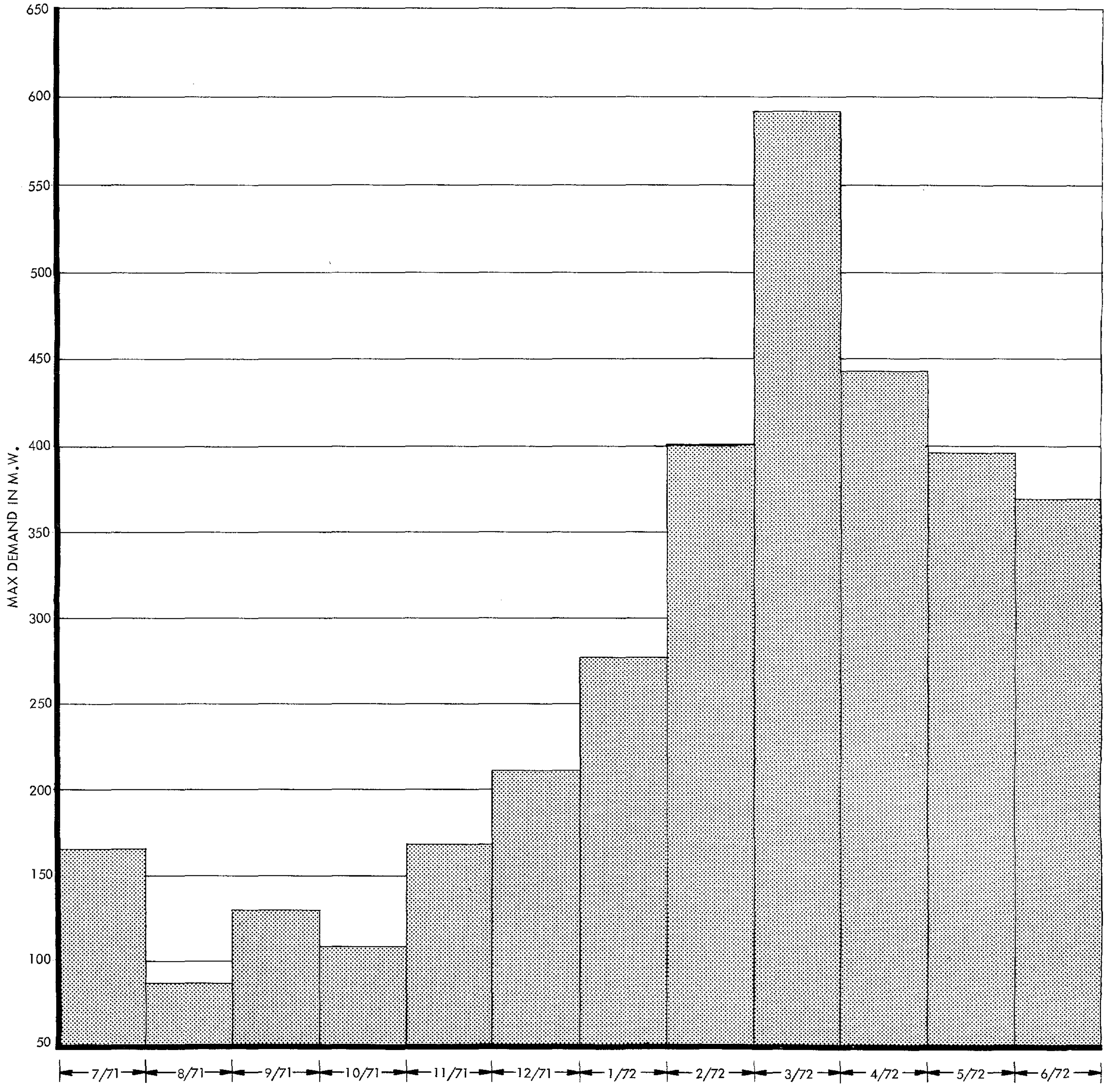

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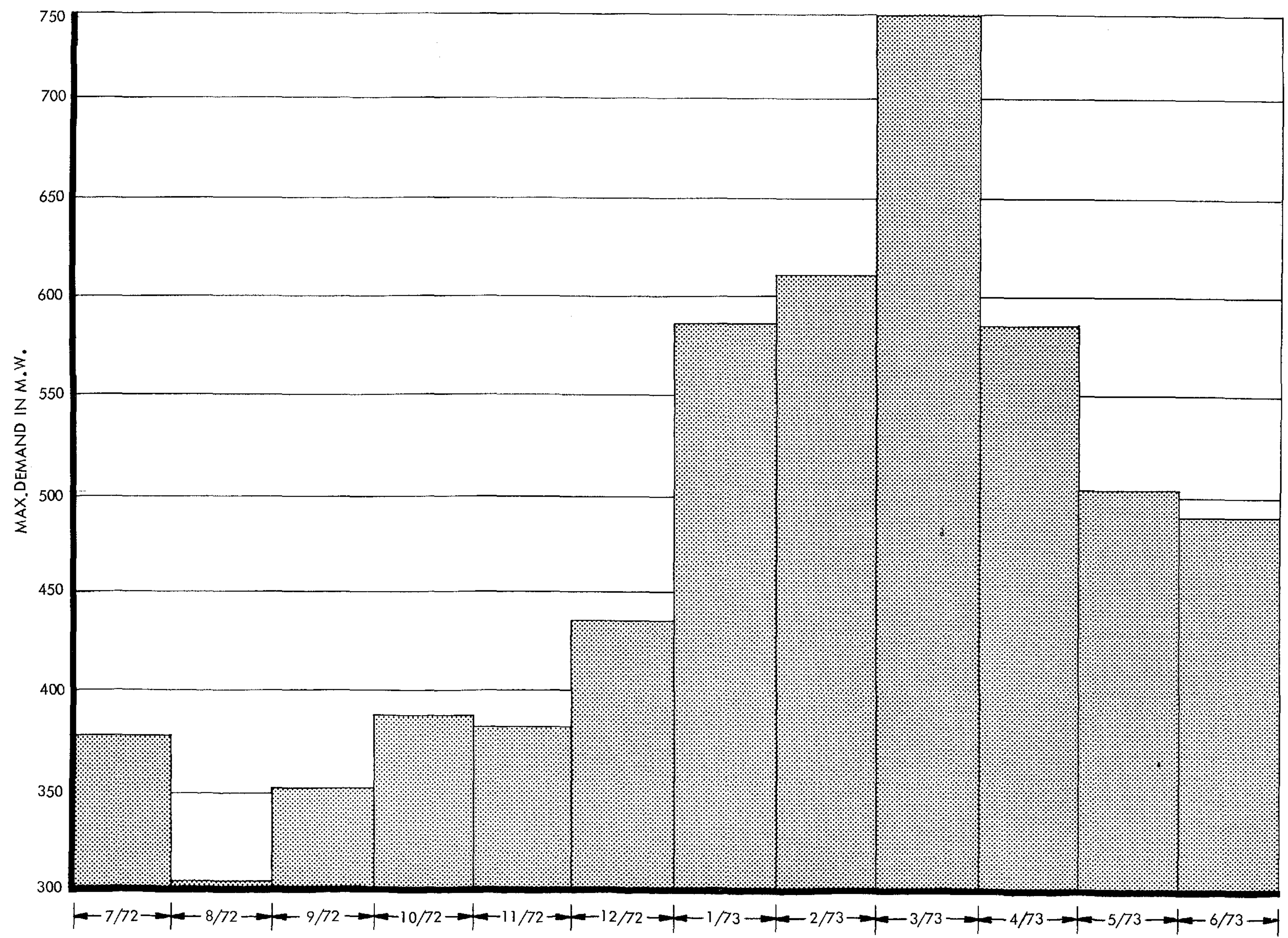
Figure 5.9

FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY
NORTHERN GRID 1972-73



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FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY NORTHERN SIND & NORTHERN GRID 1973-74

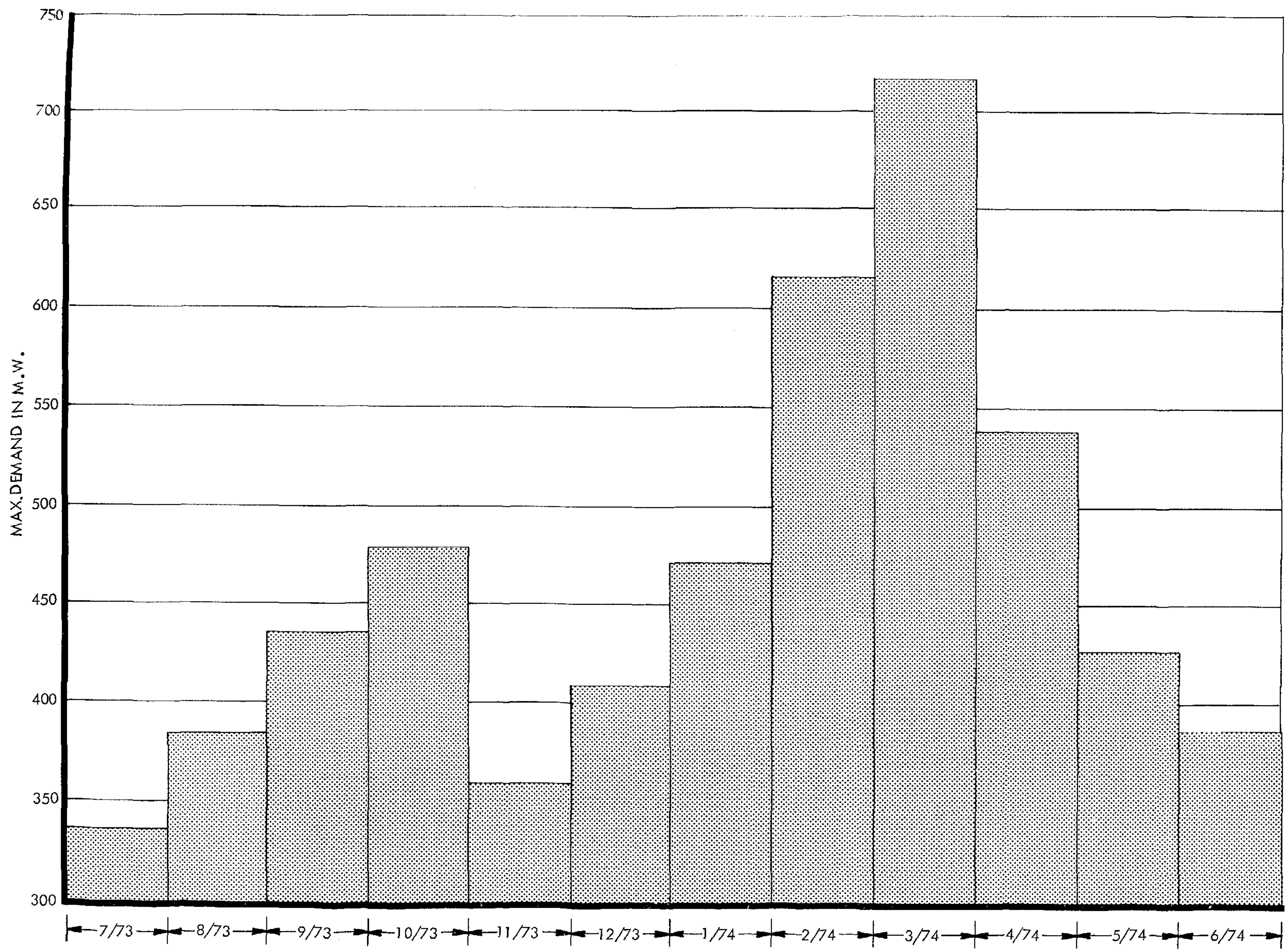

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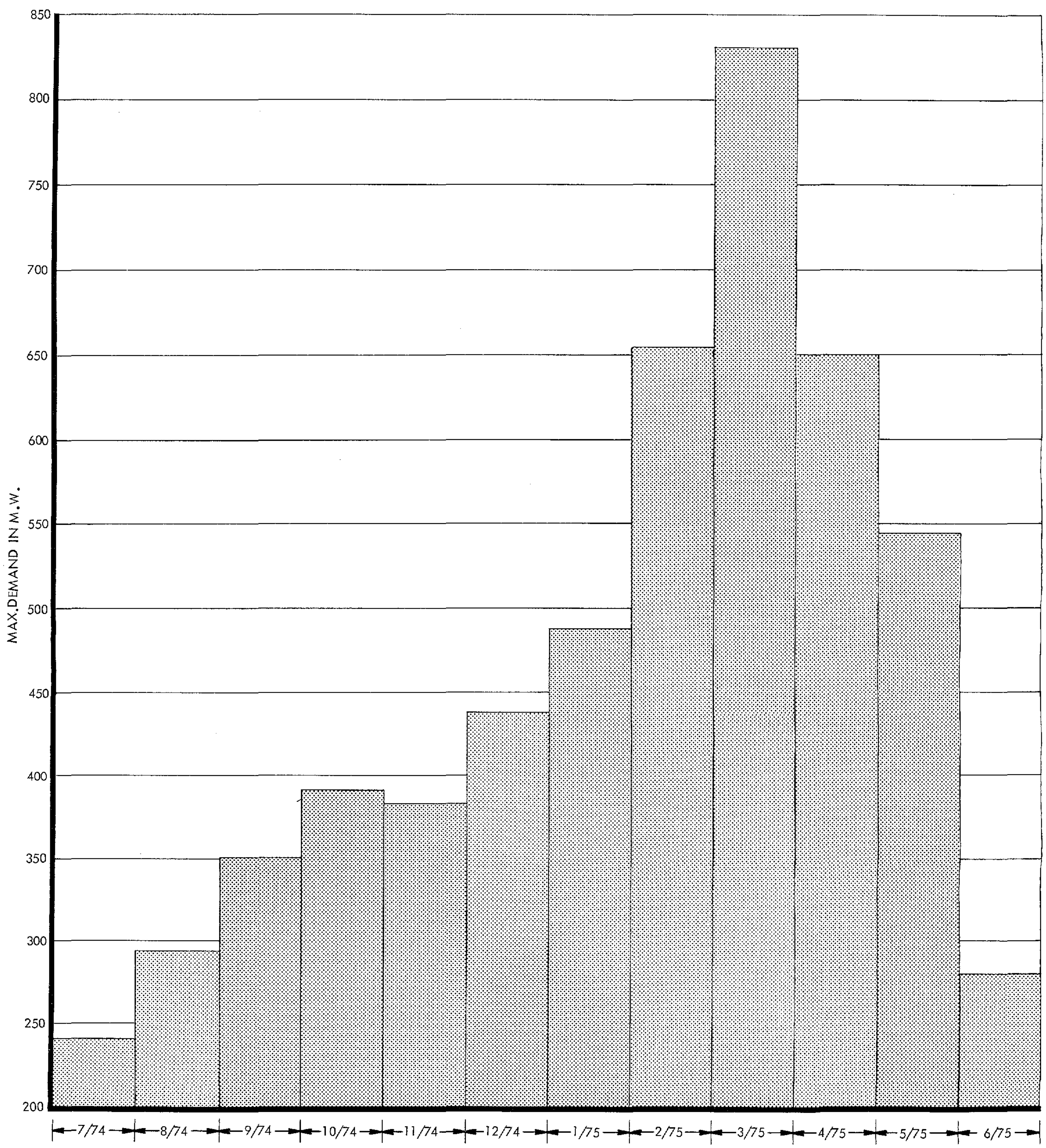
Figure 5.10

Figure 5.11

FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY NORTHERN SIND & NORTHERN GRID 1974-75



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FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY

WEST PAKISTAN 1975-76

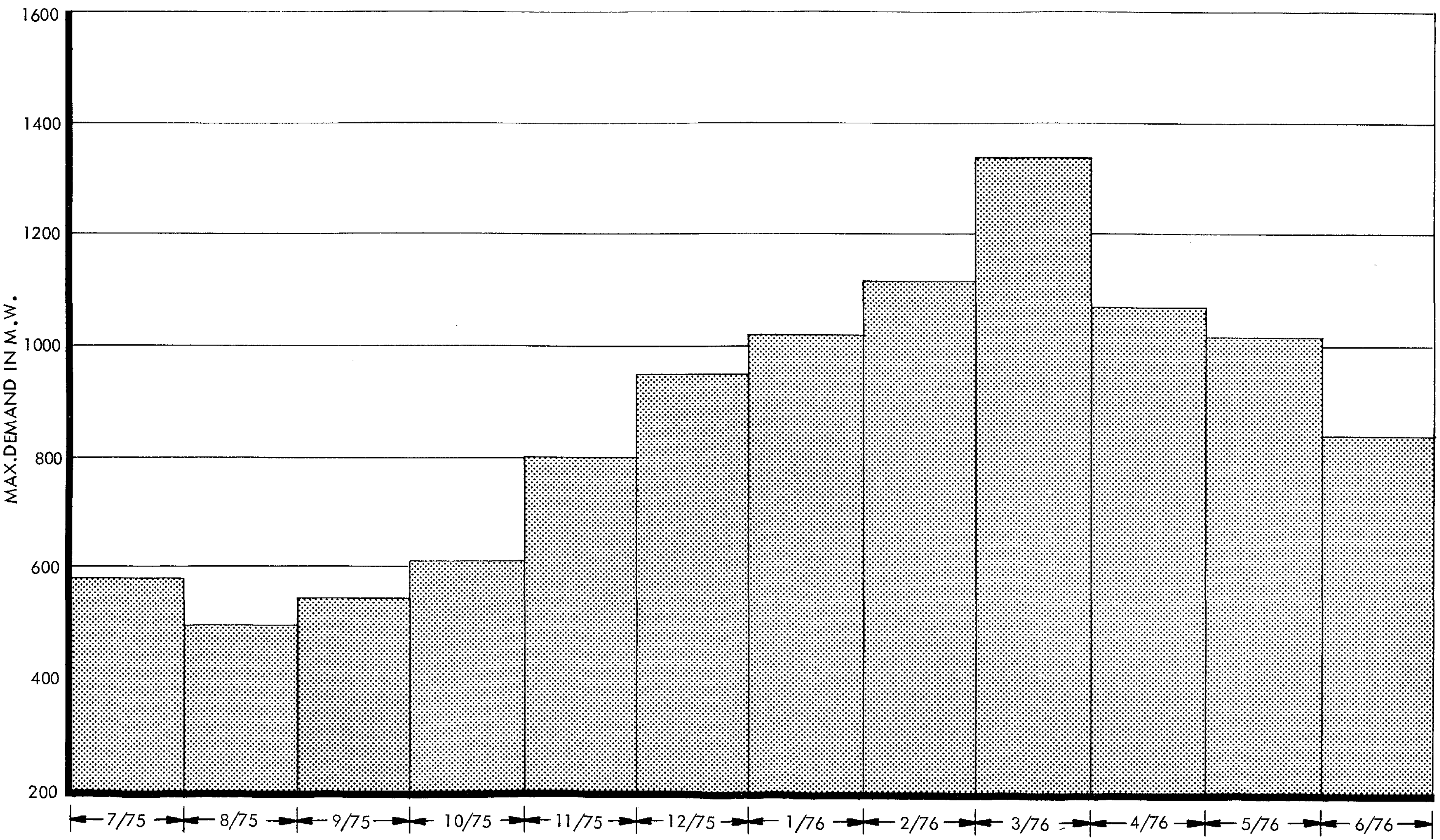

Figure 5.12

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FORECAST OF MONTHLY PEAK LOAD LESS HYDRO CAPABILITY

WEST PAKISTAN 1980-81

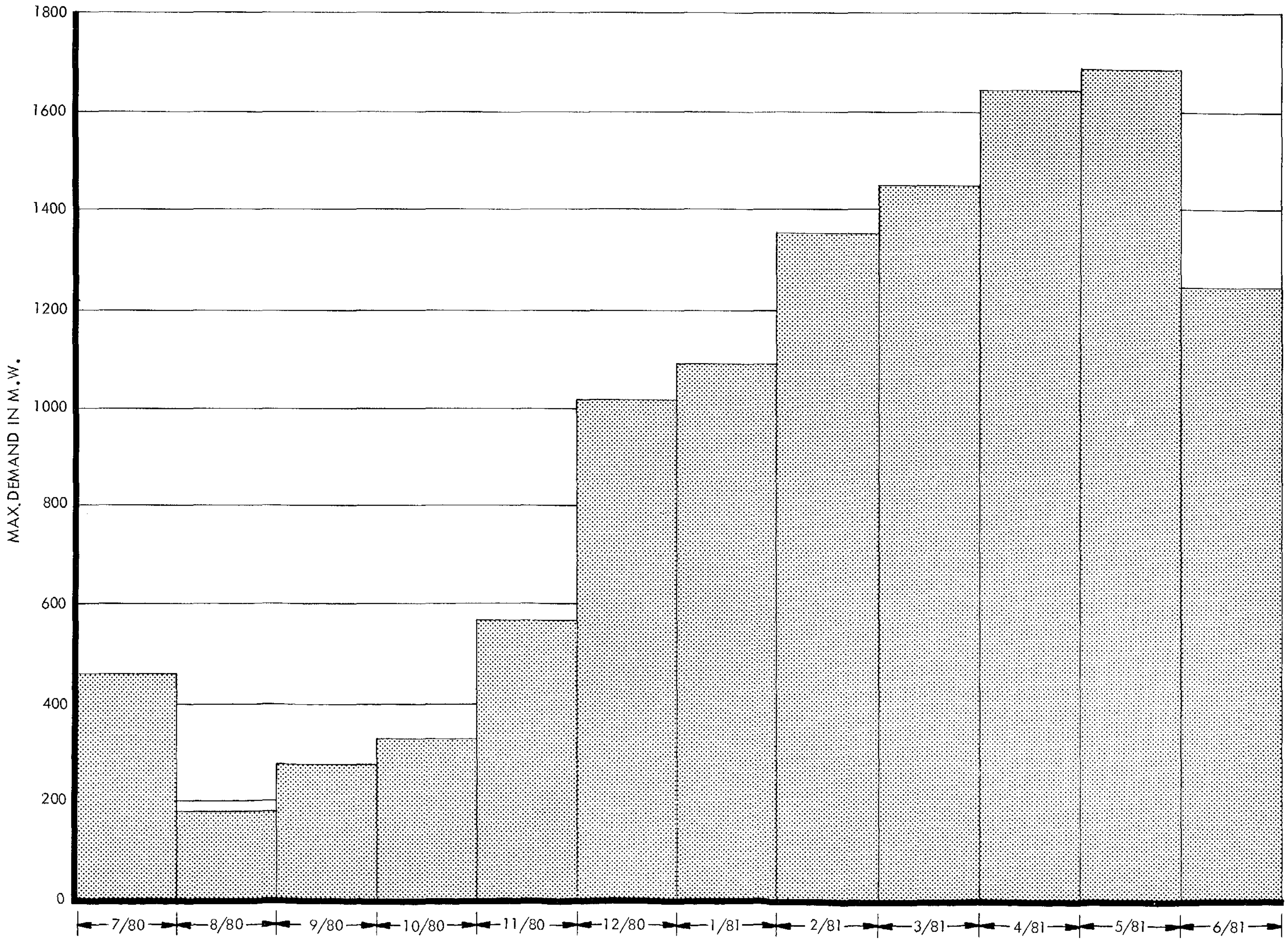

Figure 5.13

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likely to have two distinct effects on the general picture outlined. Because of, say, less than average water inflow, demands on thermal plants will rise, especially during the second half of the calendar year: the reservoirs will not be filled, hydraulic heads will be lower than projected, and scheduled reservoir discharges will be cut back during this part of the year. As a consequence additional load and energy will have to be provided by thermal capacity during these months. However, corresponding additional burdens will not be placed on the thermal system during the succeeding months -- particularly during March, April, or May when the reservoir is scheduled to be virtually empty in the normal year. But there is a second consequence from the shortage of irrigation water in the canals. Farmers will attempt to demand more power and energy to operate their tubewells so as to substitute for irrigation water available in normal years from canals. Thus, during the months that less irrigation water is available from reservoirs, electric power and energy demands may increase from agriculturalists' efforts to adjust to the shortage. Above average water years, on the other hand, may have somewhat reversed effects with reservoir storage carried over into the subsequent year. Unfortunately, not enough data are available to project how Figures 5.6 to 13 would appear either for a below-average or an above-average water year.

5.21 The foundations for a WAPDA seasonal price structure are presented in Figures 5.6 to 5.13. It is clear where price incentives are to be provided to encourage consumption and where they are needed to discourage consumption.

Tubewell Loads and Seasonal Stresses

5.22 In order to analyze further the seasonal stresses on the WAPDA system, the agricultural requirements for electric energy (agricultural pumping), which are, indeed, very substantial (now about 25%) and expected to grow in relative importance for a number of years at least have been treated separately. Attempts have been made to estimate future agricultural loads, from both private and public tubewells, on the basis of the limited load research undertaken for this study in West Pakistan and described in Chapter 4, projected growth rates of tubewell connections, data variously available relating to tubewell utilization rates (including those collected by the Pakistan Institute of Development Economics - PIDE), and reports by the World Bank's irrigation and agriculture consultants Sir Alexander Gibb and Partners and Associates.

5.23 Table 5.3 presents alternative projections for growth of public and private tubewell loads and energy requirements as reported by Gibb and Associates to the World Bank in 1970. For purposes of this study the lower public tubewell and the higher private tubewell growth projections are used.

TABLE 5.3

ESTIMATED ANNUAL ENERGY AND POWER REQUIREMENTS OF PUBLIC AND PRIVATE TUBEWELLS BY 1975

(All figures are measured as sent out power)

Energy

Present (1970) low projection (3,000 public tubewells)		
Public Tubewells	-	1,105 million kWh
Private Tubewells	-	1,038 million kWh
	Total (say)	2,100 million kWh
Present (1970) high projection (7,000 public tubewells)		
Public Tubewells	-	1,480 million kWh
Private Tubewells	-	976 million kWh
	Total (say)	2,500 million kWh
IACA/Stone & Webster 1965 projection		3,750 million kWh

Power Demand

(Gross-without allowance for peak shaving)		
Present (1970) low projection		
Public Tubewells		220 MW
Private Tubewells		330 MW
	Total	550 MW
Present (1970) high projection		
Public Tubewells		310 MW
Private Tubewells		310 MW
	Total	620 MW
1965 IACA/Stone & Webster *		739 MW

* With allowance for peak shaving in public tubewell fields Stone & Webster reduced the gross demand to 624 MW for 1975.

SOURCE: Sir Alexander Gibb and Partners and Associates, Report of Indus Basin Review Mission June 1970, P.287.

5.24 The upper branch of the curve on Figure 5.14 shows the projection for private tubewell growth. This projection has been extended for some of the purposes of this study, and estimates have been made of expected monthly private pumping loads to 1,990. The details of the procedure for estimating the growth of load by months for both private and public tubewells are given in Annex 8. The monthly patterns combined with the projected growth for one year, 1970-71, are summarized in Figure 5.15. It should be noted that loads in this discussion refer to power consumed during periods of daily peak demands on the system -- not connected load, average load, or the like.

5.25 As pointed out earlier, one of the self-imposed ground rules for this pricing study is to take for granted the planned reservoir rule curves and the resulting projected monthly variations in hydroelectric capabilities determined by the requirements for the "green revolution". A companion ground rule is the assumption that the amount of electric energy required each month for purposes of agricultural pumping by private and public tubewells is similarly given and fixed. Of course, accepting such ground rules does not mean "approving" the load curve for agricultural pumping any more than it does "approving" the rule curves. Serious questions can and need to be raised on whether the presently effective price structure for electricity which causes running costs of tubewells often to be close to zero incrementally all day long (see Chapter 3 on the difficulty of metering energy delivered to tubewell customers) is not a wasteful diversion of electricity generating resources at least during some months out of the year. Generally, when water in reservoirs is scarce and electricity is expensive to produce, efficiency requires that irrigation water -- whether from surface reservoirs or from underground reservoirs -- should be treated by all users as a costly resource.

5.26 In Figure 5.16 there is plotted for years 1970-71 and 1975-76 the non-agricultural demand on the WAPDA integrated system. It represents the projected industrial, commercial and residential demand for the present Northern Grid in 1970-71 and for the Northern Grid-Upper Sind interconnection in 1974-75, obtained as a residual. The estimates are obtained by subtracting from the Harza total demand projections the Harza public tubewells projections provided in Table C-4 of Annex 7 and subtracting the private tubewell projection made in this study. The procedure is, of course, logically equivalent to first modifying the Harza total demand projection by subtracting the Harza public tubewell demand projection and replacing it with the public tubewell demand projection of this report, and then subtracting from this total the private and public tubewell demands estimated in this study. Figure 5.17 gives comparisons between the Harza forecasted public tubewell seasonal demand pattern and that developed for this study. The picture of the monthly loads in Figure 5.16 is not atypical of a seasonal load pattern in the northern hemisphere for a power system in an economy without substantial irrigation, heating and airconditioning loads. The fact that the winter lighting load is clearly evident does give confidence that the monthly Harza total load projections together with the separate private tubewell load projections made in this study may be consistent with each other. 1/

Industrial Tariffs

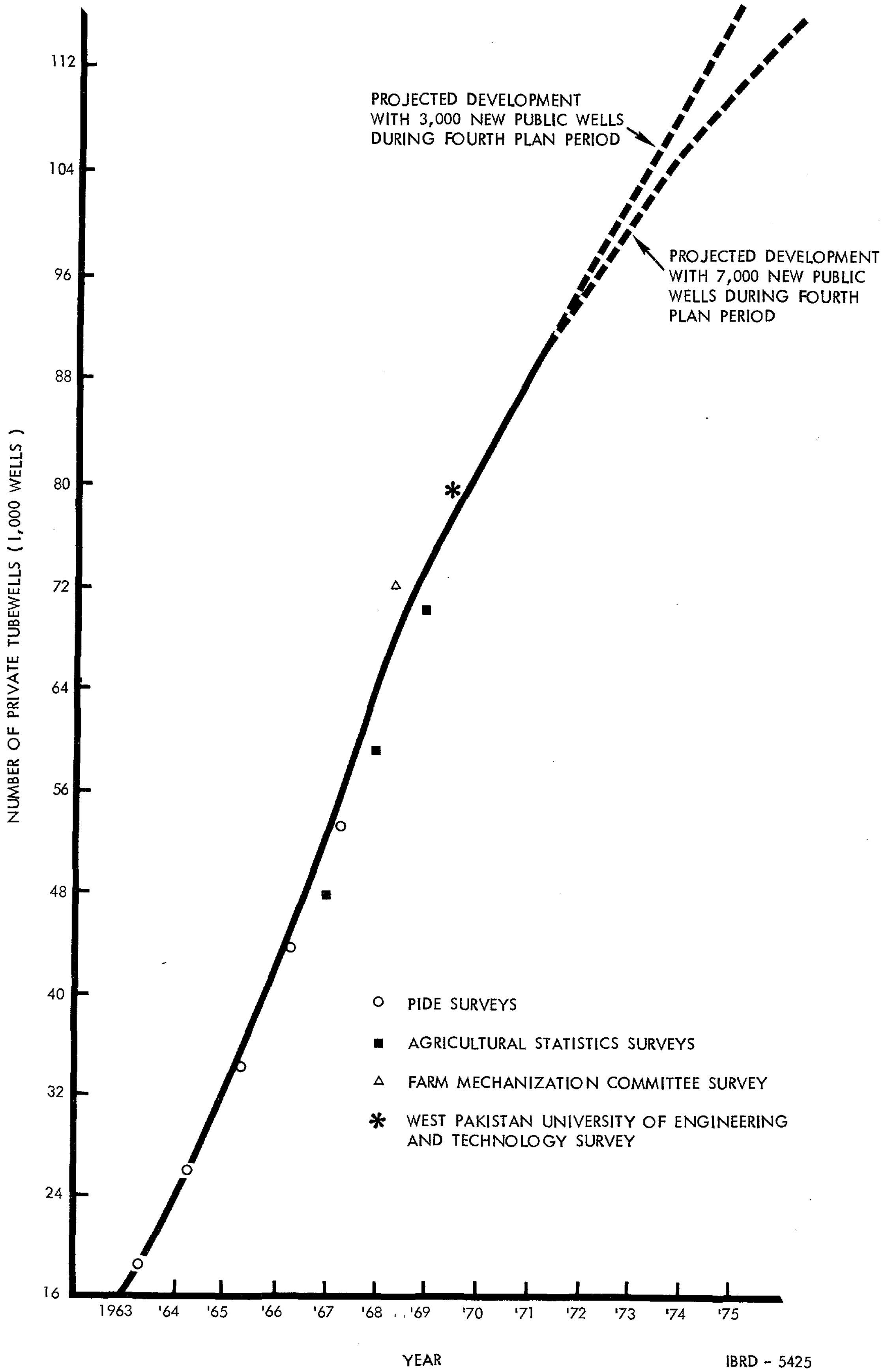
5.27 The basis for the specific recommendation made earlier in Chapter 2 that WAPDA adopt industrial tariffs providing incentives discouraging load and energy consumption during some months and encouraging it during others is provided by diagrams like those of Figure 5.18. This graph shows for the years 1970-71 and 1974-75, as sample years, the thermal electric power requirements for non-pumping loads. The data are Harza projections, except for the private tubewell loads which were developed for this study. The chart shows as positive quantities the thermal plant capacity required to meet the load of industrial, commercial and residential customers, given the rule curves and hydroelectric capabilities and given that the agricultural tubewell demand has been met. The graph shows as negative quantities the thermal capacity surplus for these loads. Evidently during June, July, August, September and October there is actually a "surplus" of thermal capacity to meet all non-agricultural demands. Load shifted from the December through May months to the summer and autumn months through price incentives offered to industrial customers could thus lead to substantial savings in thermal capacity. In principle seasonal incentives might also be given to residential and commercial customers. However, it is believed that very few residential and commercial customers would be likely to respond to price incentives so as to reschedule substantially their consumption of electric energy. Of course, the picture does suggest that airconditioning loads might be encouraged if no higher priority uses can be found for the thermal capacity available in summer months. 2/

5.28 As a first measure it is firmly recommended that industrial demand charges have substantial seasonal differentials. These differentials should be widely publicized both among customers and among WAPDA employees responsible for metering and billing. In addition substantial seasonal differentials should also be reflected in energy charges. Some illustrations of such industrial two-part tariffs are provided in Chapter 2 (see in particular paragraphs 2.31 through 2.36). Only after much publicity and ample opportunity has been provided for industrial consumers to respond to the cost penalties for winter-spring loads and rewards for summer-fall loads -- say, at least two or three full years -- should such other alternatives as the encouragement of airconditioning loads be considered.

1/ The May loads are, however, unaccountably high.

2/ The limitations of this analysis: forecast errors, average water availability, absence of transmission restrictions, etc., must be borne in mind.

PROJECTED PRIVATE TUBEWELL GROWTH IN WEST PAKISTAN



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THE PROJECTED MONTHLY PATTERN OF PUBLIC AND PRIVATE TUBEWELL POWER DEMANDS, WEST PAKISTAN 1970-71

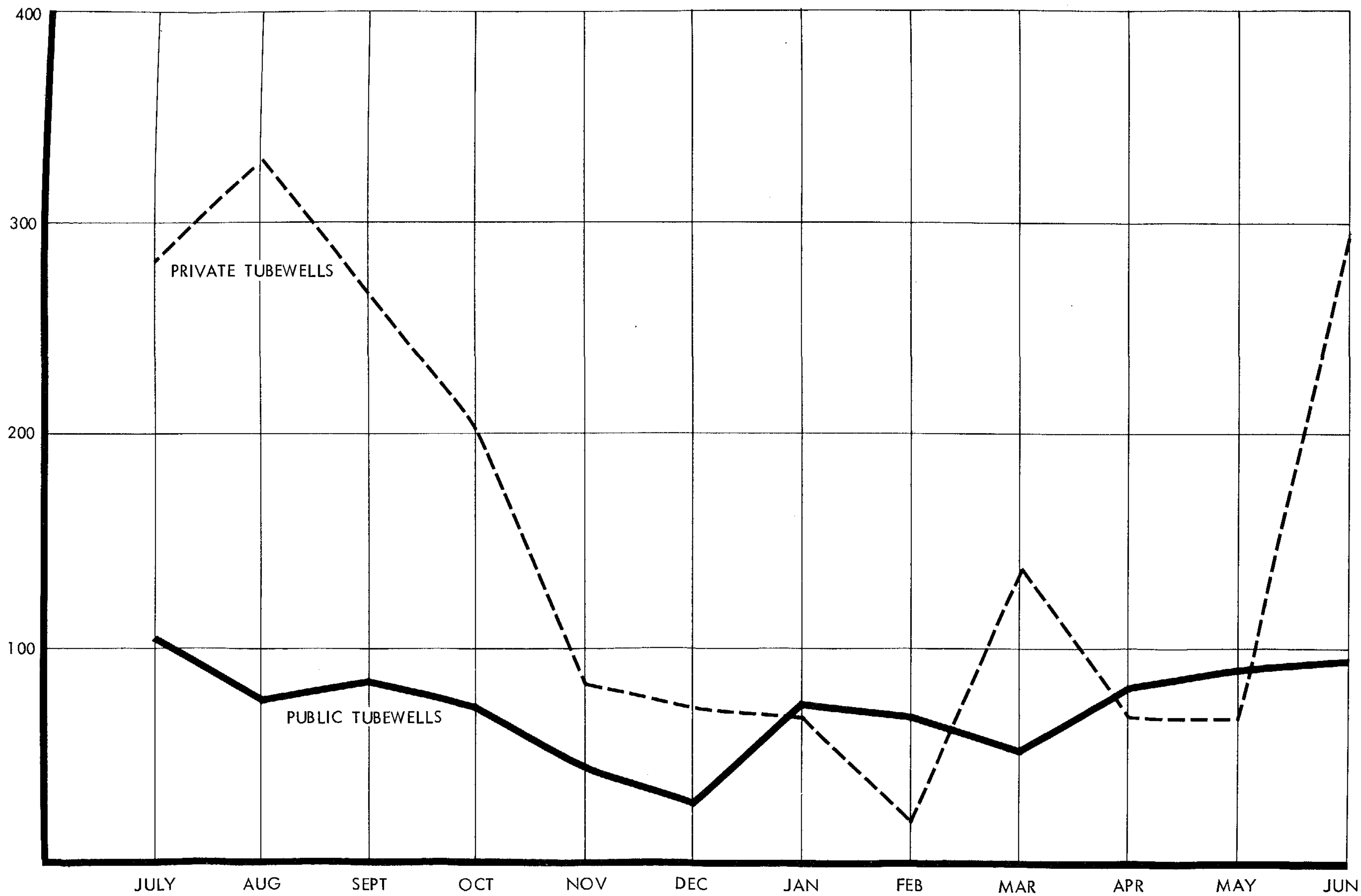
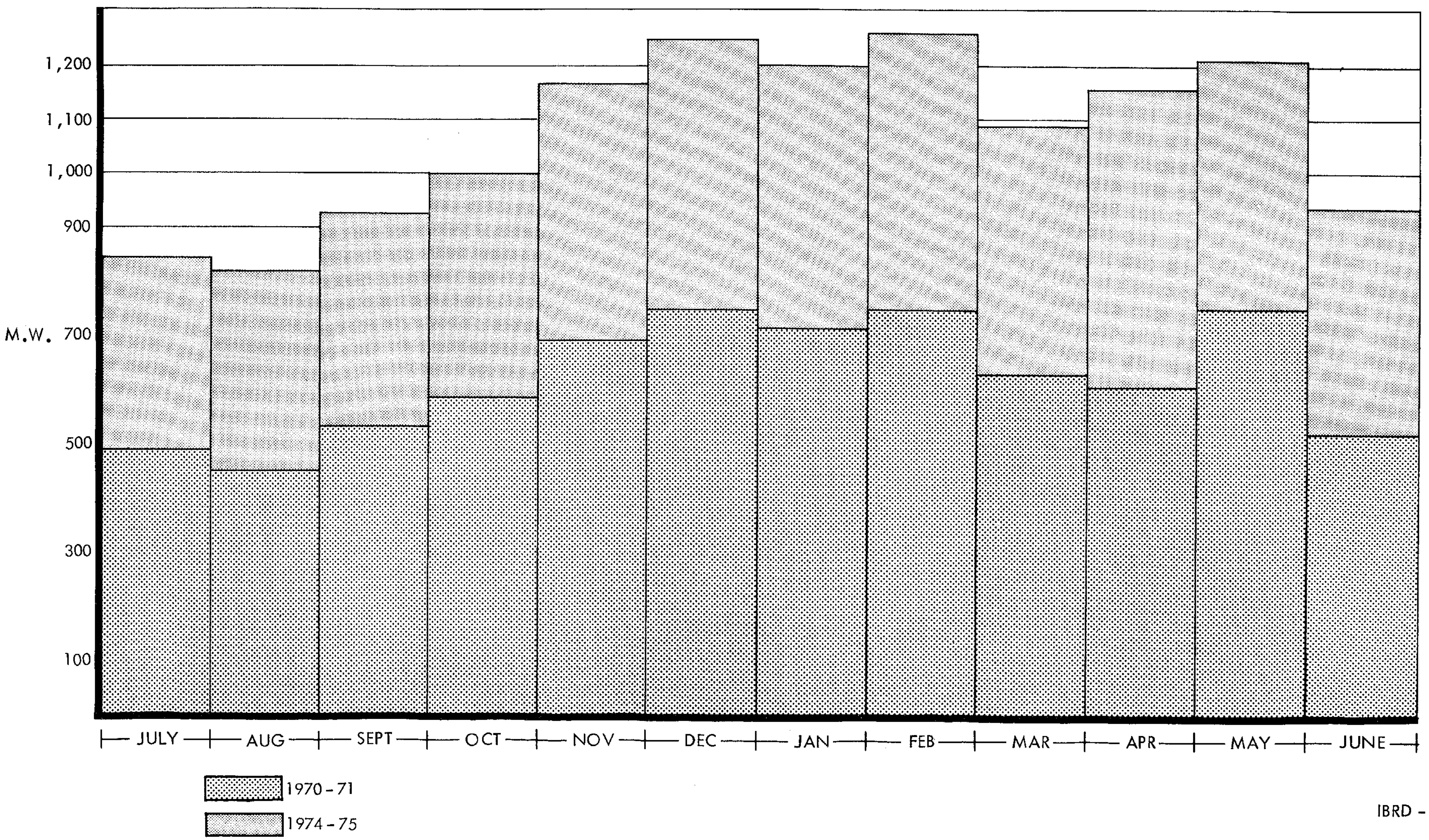


Figure 5.15

IBRD - 5426

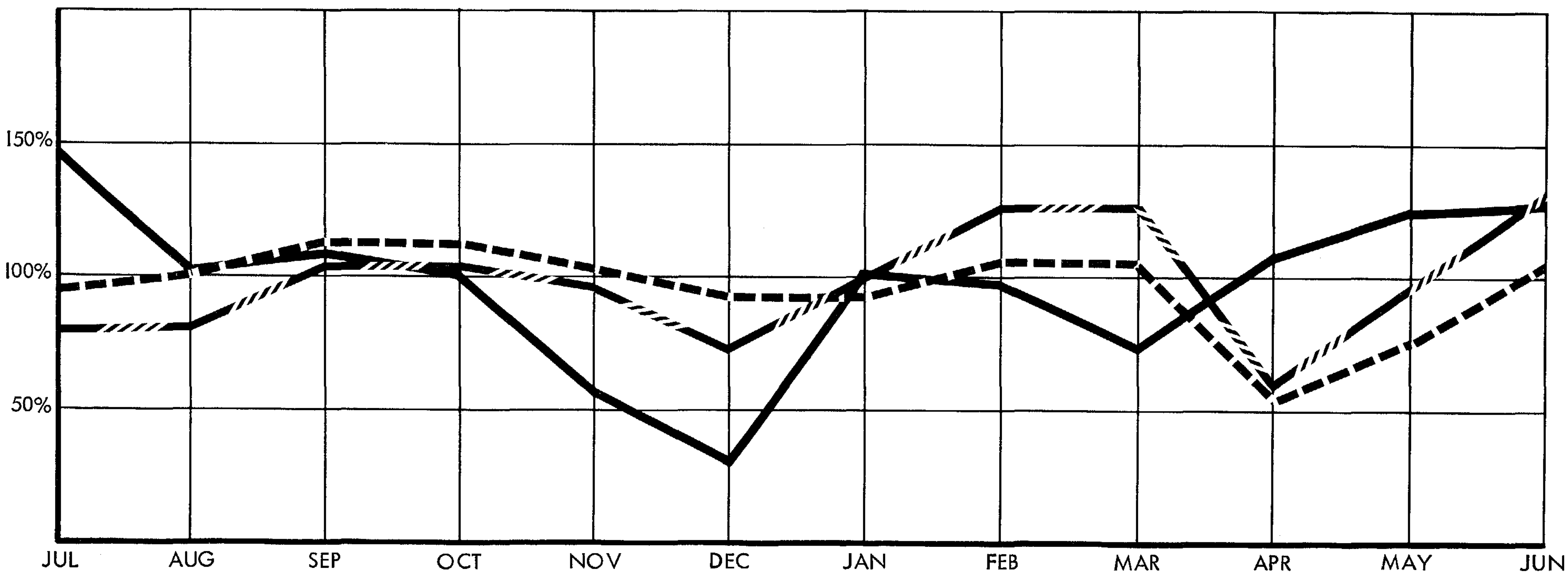
PROJECTED INDUSTRIAL, COMMERCIAL AND RESIDENTIAL POWER DEMAND PATTERN OBTAINED AS RESIDUAL 1970-71, NORTHERN REGION 1974-75, NORTHERN-UPPER SIND INTERCONNECTION



IBRD - 5427

Figure 5.16

COMPARISON OF SEASONAL PATTERN IN PUBLIC TUBEWELL DEMAND FORECASTS



BOGGIS WESTFIELD FORECASTS ('70 - '71)
HARZA FORECASTS ('70 - '71)
HARZA FORECASTS ('72 - '73)

100% = AVERAGE LOAD FOR A PERIOD OF 12 MONTHS.

Figure 5.17

IBRD - 5428

THERMAL POWER REQUIREMENTS FOR NON-PUMPING LOADS IN M.W.

1970-71 AND 1974-75

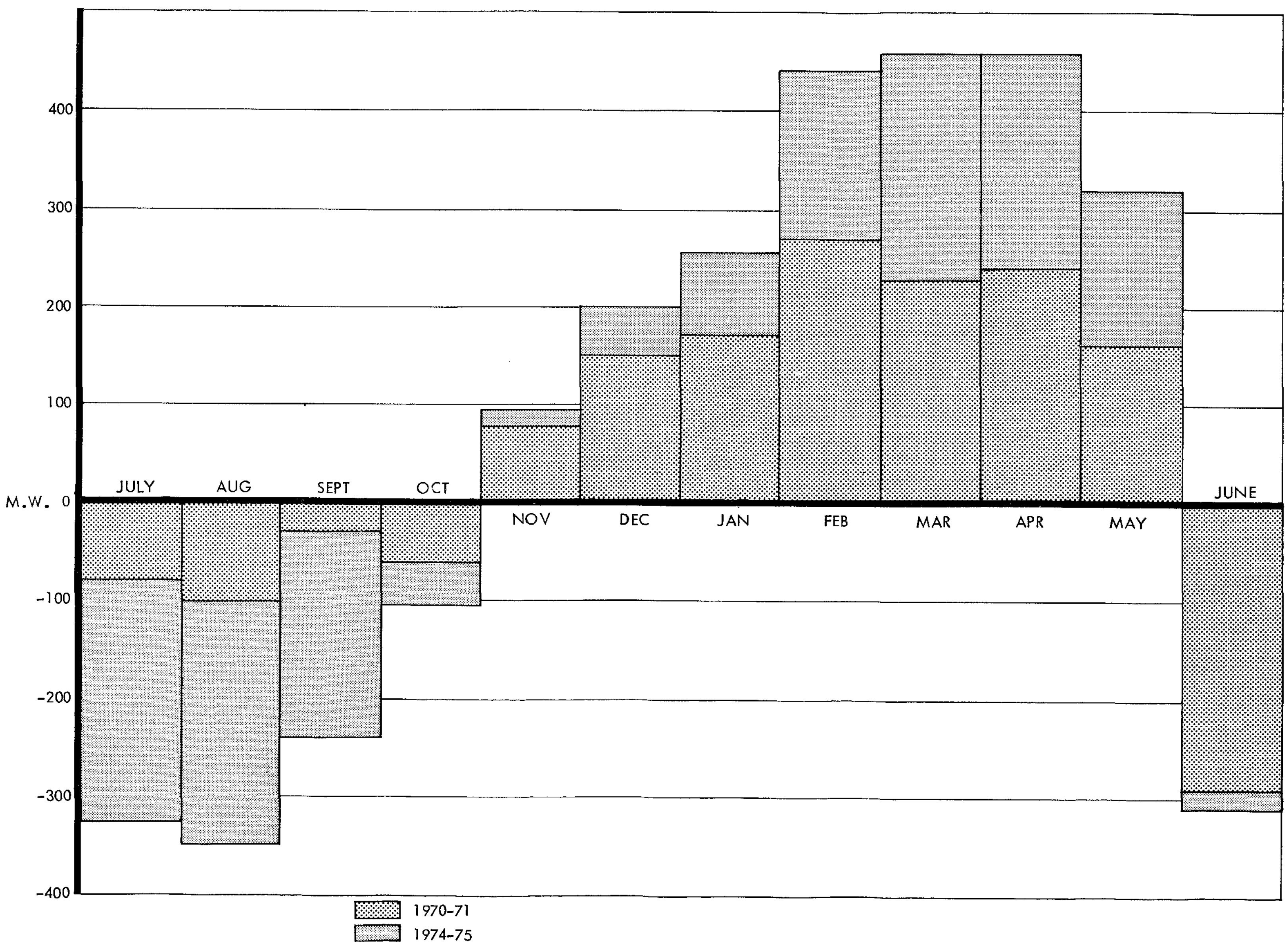


Figure 5.18

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5.29 The savings to be realized from shifting industrial load from winter-spring to summer-fall have not been estimated. Tariff adjustments could be readily made in a way such that the industrial consumer taking the same load and consuming the same energy month after month would during the course of a year incur the same annual bill for electric service as he does under existing tariffs -- that the consumer who concentrates his load and energy off-take during the summer-fall months will realize a saving and he who concentrates it during the winter-spring months will incur additional expense. If consumers were not to react at all to the incentives the new seasonal tariff could be set at levels so that total WAPDA revenues from industrial consumers would not be affected. To the extent that the customers do respond, the tariffs can be in due course adjusted so as to ensure that WAPDA cost savings from the seasonally restructured load exceed any revenue losses. Given the present and prospective state of cost accounting within WAPDA, even approximate evaluations of cost savings to be realized under various assumed demand shifts may be quite difficult. But there seems to be no doubt (1) that demand shifts from winter-spring to summer-fall are cost-saving to WAPDA and (2) that tariffs can be changed so as to ensure that total revenues need not decline. It is believed that any additional costs incurred by consumers to take advantage of the price differentials will be less in overall terms than the savings in the cost of economic resources by WAPDA.

5.30 WAPDA should also explore the possibility of introducing optional time-of-day industrial tariffs with a view toward shifting load to night-time. This report does not endorse a specific experiment because industrialists who were interviewed and whose enterprises were not now operating night shifts saw great difficulties in substituting night-time for day-time operations. They emphasized various institutional difficulties, most of them centering on problems relating to the labor force. Foreign researchers, as those who undertook the study leading to this report, spending barely two months in a country as strange, vast and complex as West Pakistan, can hardly be expected to be able to resolve such questions. Enforcement of existing two-part tariffs is, as was pointed out in earlier chapters, already fraught with difficulties. But perhaps WAPDA could offer to small categories of industrial customers tariffs related to the time of day on an experimental and optional basis as soon as the metering and billing problems can be solved.

Agricultural Tariffs

5.31 Agricultural pumping loads, it is believed, may be particularly sensitive to time-of-day tariff variation. It is recommended that WAPDA undertake some specific experiments with time-of-day tariffs for private tubewell operators. The details of the recommended experiments will be outlined below. However, first, the characteristics of the private tubewell demand as projected for this study for the next twenty years will be explored. Then, alternative demands, which appropriate tubewell tariff construction may be able to effectuate, will be analyzed. Finally with the help of the World Bank's computer model (the Jacoby model) of the

West Pakistan power system, the benefits to the power system of the alternative demands will be evaluated and related to the costs to be incurred in restructuring private tubewell power demands.

5.32 The earlier presentation of private tubewell load curves (Chapter 4), the earlier discussion in this chapter and also the data of Table 5.4 make it quite evident that monthly utilization rates of private tubewells, though variable from month to month and location to location, average probably less than 25% and may even be as low as 20%.

TABLE 5.4

PRIVATE TUBEWELL UTILIZATION RATES FROM SAMPLE SURVEY

(per cent)

Area	Type of Area	Early Kharif	Late Kharif	Kharif	Early Rabi	Late Rabi	Rabi	Annual
Pakpattan	Non-Perennial	21.0	22.6	21.8	31.9	26.2	29.0	25.4
Lodhran	" "	21.1	17.2	19.2	23.0	36.5	29.8	24.5
Khanewal	Perennial	15.0	11.1	13.1	22.8	14.3	18.5	15.8
Samundri	"	15.5	18.5	17.0	23.2	20.5	21.8	19.4
Kasur	Non-Perennial and Uncommanded	11.0	19.5	15.2	12.4	13.7	13.1	14.2
Kanganpur	Non-Perennial	13.8	6.9	10.4	8.5	21.5	15.0	12.7
Kamoke	" "	23.8	21.7	22.8	16.0	9.8	12.9	17.9
Haifizabad	" "	17.4	33.2	25.3	18.8	13.9	16.4	20.9
Average (uncorrected)		17.3	18.8	18.1	19.6	19.6	19.6	18.8
Average corrected for theft		18.3	19.9	19.2	20.8	20.8	20.8	20.0

Source: Sir Alexander Gibb & Partners and Associates, Report of Indus Basin Review Mission June 1970, P. 74.

5.33 The cost-benefit calculation involved estimation of benefits for the power sector that would be derived from keeping each day the amounts of electric energy devoted to the operations of private tubewells unchanged, at the same time that the time profile of the rates of consumption of the energy would be altered in one or the other of two specific ways. Thus, the amount of water to be available from each tubewell every day was assumed to be unchanged.

5.34 Tariff plan A 1/ for private tubewells is one which imposes an effective penalty charge for kWh consumed during a four-hour period from 16.30 to 20.30 hours, the time period coincident with the system peak. Because of the relatively short duration (four hours) over which penalties are to be incurred in operating tubewells and their relatively low intensity of use during typical days, the assumption in carrying out the calculations is that the decrease in load occurring during these four hours will be added during the rest of the day without raising the night-time minimum between midnight and 05.00 of the load curve. Table 5.5 (a) sketches the assumed realignment of the load for an assumed change in load ΔL. Table 5.5 (b) illustrates the implications of these assumptions for the private tubewell load for an assumed "75% effectiveness" of the tariff. This assumption of 75% effectiveness of the type A tubewell tariff and the corresponding reduction in Northern Grid's monthly peak loads without either raising monthly minimum loads or altering monthly total system energy supply 2/ provide the load changes for the analysis and computer simulation of tariff plan A.

5.35 Tariff plan B for private tubewells is essentially a day-night tariff. For the purposes of the computer simulation and analysis it was imagined that the higher rates would be in effect perhaps for 14 daytime and evening hours and the lower rates for the rest of the time. This tariff plan is assumed to be structured so as to leave average daily energy consumption unchanged in order to be faithful to the self-imposed ground rules regarding irrigation requirements. At the same time that the peak of the private tubewell demand is reduced by an assumed 53%, the trough of the tubewell demand is increased by 53%. Tables 5.6, 5.7 and 5.8 show the relationships of monthly maximum loads, ratio of minimum to maximum load, and load factors for the three alternative system demands. Table 5.9 gives the basis for the assumption that only demand in the North is affected by tariff plans A & B.

5.36 It must be emphasized that the assumed effects of the tariff changes are rough estimates. One cannot at this time know exactly how agricultural electricity consumption would respond to time-of-day variations for kWh consumed. Nevertheless, it is believed that relatively simple rate changes could be made which, when used in conjunction with available meters and timing devices, would have the sort of responses assumed for the computer simulations. All this assumes that the problems caused by dishonesty are effectively controlled.

1/ Also called pricing strategy or simply plan.

2/ Monthly system load factors are accordingly increased.

TABLE 5.5

PRIVATE TUBEWELLS

Assumed result of Load-Control Differential Pricing

Section (a) Energy Balance for Equal Pumping Before and After

Integrating Period	Duration hours	On-hour reading	Assumed Load Change	Energy Balance
00:30 - 5:30	5	1 - 5	0	0
5:30 - 11:30	6	6 - 11	+ 0.2△L	+ 1.2△L
11:30 - 16:30	5	12 - 16	+ 0.4△L	+ 2.0△L
16:30 - 20:30	4	17 - 20	-△L	- 4.0△L
20:30 - 00:30	4	21 - 24	+ 0.2△L	+ 0.8△L
	24	24		0

Section (b) Demand Changes Assumed in Section (a) with 75% effectiveness

Integrating Period	Duration hours	Existing load, %	+ Load increments %	Effectiveness Proportion of farmers responding
00:30 - 5:30	5	-	0	None
5:30 - 11:30	6	-	+ 15	1 in 7
11:30 - 16:30	5	-	+ 30	1 in 3
16:30 - 20:30	4	100*	- 75	3 in 4
20:30 - 00:30	4	-	+ 15	1 in 7
	24			

* Averaged over the four hours, i.e. quarter sum of 5 to 8 p.m. readings on station ammeters.

\+ Tariff assumed 75% effective, including an allowance for meter, time-switch tampering. Note that this column means that 15% of the load between 4.30 and 8.30 p.m. is to be added to that existing between 5.30 and 11.30 a.m., and so on.

TABLE 5.6

WEST PAKISTAN INTEGRATED POWER SYSTEM - BASIC

MARKET DATA

MARKET NUMBER 1 (NORTHERN GRID)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	920.	944.	944.	870.	918.	986.	988.	1025.	1067.	1047.	1014.	1037.
1972	1025.	1052.	1052.	970.	1023.	1099.	1101.	1142.	1189.	1167.	1130.	1155.
1973	1136.	1165.	1165.	1074.	1133.	1217.	1219.	1265.	1317.	1293.	1252.	1280.
1974	1252.	1284.	1284.	1184.	1250.	1342.	1344.	1395.	1452.	1426.	1380.	1411.
1975	1365.	1400.	1400.	1291.	1362.	1462.	1465.	1520.	1583.	1554.	1505.	1538.
1976	1500.	1539.	1539.	1419.	1497.	1607.	1611.	1671.	1740.	1708.	1654.	1690.
1977	1647.	1689.	1689.	1557.	1643.	1764.	1768.	1835.	1910.	1875.	1815.	1856.
1978	1802.	1848.	1848.	1704.	1798.	1931.	1935.	2007.	2090.	2052.	1986.	2031.
1979	1983.	2034.	2034.	1875.	1979.	2125.	2129.	2209.	2300.	2258.	2186.	2235.
1980	2127.	2182.	2182.	2012.	2123.	2279.	2284.	2370.	2467.	2422.	2345.	2397.
1981	2302.	2361.	2361.	2177.	2297.	2467.	2471.	2565.	2670.	2621.	2538.	2594.
1982	2488.	2551.	2551.	2353.	2482.	2665.	2670.	2771.	2885.	2832.	2742.	2803.
1983	2673.	2741.	2741.	2528.	2667.	2864.	2869.	2978.	3100.	3043.	2946.	3012.
1984	2850.	2923.	2923.	2695.	2844.	3053.	3059.	3174.	3305.	3244.	3141.	3211.
1985	3018.	3095.	3095.	2854.	3011.	3233.	3240.	3362.	3500.	3436.	3326.	3400.
1986	3190.	3272.	3272.	3017.	3184.	3418.	3431.	3561.	3707.	3639.	3522.	3600.
1987	3372.	3459.	3459.	3189.	3367.	3614.	3634.	3772.	3926.	3854.	3729.	3812.
1988	3564.	3657.	3657.	3371.	3560.	3821.	3849.	3995.	4158.	4082.	3948.	4036.
1989	3767.	3866.	3866.	3563.	3764.	4040.	4076.	4232.	4403.	4323.	4074.	4273.
1990	3982.	4087.	4087.	3766.	3980.	4271.	4317.	4483.	4662.	4578.	4314.	4524.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.310	0.330	0.300	0.270	0.290	0.330	0.300	0.310	0.320	0.320	0.290	0.280
1972	0.310	0.330	0.300	0.270	0.290	0.330	0.300	0.310	0.320	0.320	0.290	0.280
1973	0.310	0.330	0.300	0.270	0.290	0.330	0.300	0.310	0.320	0.320	0.290	0.280
1974	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1975	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1976	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1977	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1978	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1979	0.310	0.330	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1980	0.310	0.320	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1981	0.310	0.320	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1982	0.310	0.320	0.300	0.270	0.290	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1983	0.310	0.320	0.300	0.270	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1984	0.310	0.320	0.300	0.270	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.280
1985	0.310	0.320	0.300	0.270	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290
1986	0.310	0.320	0.300	0.270	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290
1987	0.310	0.320	0.300	0.280	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290
1988	0.310	0.320	0.300	0.280	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290
1989	0.310	0.320	0.300	0.280	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290
1990	0.310	0.320	0.300	0.280	0.300	0.320	0.300	0.310	0.320	0.320	0.290	0.290

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.625	0.654	0.615	0.553	0.593	0.650	0.609	0.620	0.645	0.648	0.591	0.576
1972	0.624	0.654	0.615	0.552	0.592	0.650	0.608	0.620	0.645	0.648	0.591	0.575
1973	0.623	0.653	0.615	0.551	0.591	0.650	0.608	0.620	0.645	0.648	0.590	0.574
1974	0.621	0.653	0.614	0.549	0.591	0.649	0.607	0.619	0.644	0.647	0.590	0.573
1975	0.620	0.652	0.614	0.548	0.590	0.649	0.607	0.619	0.644	0.647	0.589	0.572
1976	0.619	0.651	0.614	0.547	0.589	0.649	0.606	0.619	0.644	0.647	0.588	0.571
1977	0.620	0.651	0.613	0.547	0.590	0.648	0.606	0.620	0.643	0.646	0.588	0.572
1978	0.622	0.650	0.612	0.548	0.591	0.648	0.607	0.620	0.642	0.644	0.589	0.573
1979	0.624	0.650	0.611	0.548	0.593	0.648	0.608	0.620	0.640	0.642	0.589	0.574
1980	0.625	0.649	0.610	0.549	0.594	0.647	0.609	0.621	0.638	0.640	0.590	0.574
1981	0.626	0.649	0.609	0.550	0.595	0.647	0.610	0.621	0.637	0.638	0.590	0.575
1982	0.625	0.648	0.609	0.550	0.597	0.647	0.610	0.621	0.637	0.637	0.591	0.576
1983	0.625	0.648	0.608	0.552	0.598	0.646	0.609	0.620	0.636	0.636	0.592	0.577
1984	0.624	0.647	0.608	0.554	0.600	0.646	0.609	0.620	0.636	0.635	0.593	0.578
1985	0.624	0.647	0.607	0.556	0.602	0.645	0.608	0.619	0.635	0.634	0.594	0.579
1986	0.623	0.646	0.607	0.558	0.602	0.645	0.608	0.619	0.635	0.633	0.595	0.580
1987	0.623	0.646	0.606	0.560	0.604	0.644	0.607	0.618	0.634	0.632	0.596	0.581
1988	0.622	0.645	0.606	0.562	0.604	0.644	0.607	0.618	0.634	0.631	0.597	0.582
1989	0.622	0.645	0.605	0.564	0.606	0.642	0.606	0.617	0.633	0.630	0.598	0.583
1990	0.621	0.644	0.605	0.566	0.606	0.642	0.606	0.617	0.633	0.630	0.598	0.584

TABLE 5.6 - MARKET NUMBER 2 (KARACHI-LOWER SIND)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	323.	324.	327.	330.	338.	347.	348.	351.	360.	368.	359.	368.
1972	371.	372.	375.	379.	388.	399.	400.	403.	414.	422.	412.	422.
1973	424.	426.	429.	434.	444.	456.	457.	460.	473.	482.	471.	482.
1974	479.	480.	484.	489.	501.	514.	513.	517.	536.	542.	530.	543.
1975	534.	535.	540.	546.	558.	573.	571.	576.	592.	603.	590.	604.
1976	594.	595.	600.	606.	621.	637.	647.	652.	570.	682.	667.	683.
1977	670.	671.	677.	684.	700.	719.	719.	723.	744.	757.	741.	759.
1978	742.	743.	750.	757.	775.	796.	797.	802.	825.	839.	811.	842.
1979	821.	822.	828.	836.	855.	879.	866.	873.	897.	913.	893.	916.
1980	889.	890.	897.	906.	926.	952.	955.	962.	989.	1006.	984.	1010.
1981	978.	979.	985.	995.	1018.	1047.	1038.	1044.	1074.	1092.	1069.	1097.
1982	1059.	1059.	1067.	1078.	1102.	1133.	1122.	1131.	1163.	1182.	1157.	1186.
1983	1141.	1142.	1151.	1163.	1189.	1221.	1207.	1216.	1250.	1271.	1244.	1277.
1984	1224.	1224.	1234.	1246.	1274.	1310.	1291.	1300.	1336.	1359.	1330.	1374.
1985	1308.	1308.	1318.	1331.	1361.	1400.	1378.	1388.	1427.	1451.	1421.	1457.
1986	1395.	1396.	1407.	1421.	1453.	1493.	1471.	1482.	1524.	1549.	1518.	1545.
1987	1488.	1490.	1502.	1517.	1551.	1592.	1570.	1581.	1628.	1654.	1622.	1638.
1988	1587.	1590.	1603.	1620.	1656.	1698.	1676.	1688.	1739.	1766.	1733.	1737.
1989	1693.	1697.	1711.	1730.	1768.	1811.	1789.	1802.	1857.	1885.	1852.	1842.
1990	1806.	1811.	1826.	1847.	1887.	1931.	1909.	1924.	1983.	2012.	1979.	1953.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.300	0.300	0.300	0.310	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1972	0.300	0.300	0.300	0.300	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1973	0.290	0.300	0.290	0.300	0.300	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1974	0.290	0.300	0.290	0.290	0.290	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1975	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.300	0.310	0.300	0.300
1976	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290	0.310	0.300	0.300
1977	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.300
1978	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1979	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1980	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1981	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1982	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1983	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1984	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1985	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1986	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1987	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1988	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1989	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290
1990	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.660	0.662	0.661	0.665	0.670	0.663	0.665	0.658	0.664	0.668	0.666	0.667
1972	0.660	0.662	0.660	0.662	0.666	0.662	0.665	0.657	0.663	0.668	0.665	0.665
1973	0.659	0.660	0.659	0.660	0.662	0.661	0.664	0.656	0.662	0.667	0.664	0.664
1974	0.658	0.660	0.658	0.657	0.658	0.660	0.663	0.654	0.661	0.667	0.663	0.662
1975	0.658	0.658	0.657	0.654	0.654	0.657	0.662	0.653	0.660	0.666	0.662	0.661
1976	0.657	0.657	0.657	0.652	0.650	0.655	0.660	0.652	0.658	0.665	0.662	0.660
1977	0.657	0.657	0.657	0.652	0.650	0.655	0.659	0.652	0.657	0.665	0.663	0.660
1978	0.658	0.657	0.658	0.651	0.651	0.655	0.658	0.653	0.656	0.666	0.663	0.659
1979	0.658	0.658	0.658	0.651	0.651	0.655	0.657	0.654	0.655	0.666	0.664	0.659
1980	0.659	0.658	0.659	0.650	0.652	0.655	0.656	0.655	0.655	0.667	0.664	0.658
1981	0.659	0.658	0.659	0.650	0.653	0.655	0.655	0.656	0.654	0.667	0.665	0.658
1982	0.658	0.657	0.658	0.651	0.653	0.655	0.654	0.656	0.654	0.666	0.665	0.657
1983	0.658	0.657	0.658	0.651	0.654	0.654	0.654	0.655	0.654	0.665	0.664	0.657
1984	0.657	0.656	0.657	0.652	0.654	0.654	0.653	0.655	0.653	0.664	0.664	0.656
1985	0.657	0.656	0.657	0.653	0.654	0.653	0.653	0.654	0.653	0.663	0.663	0.656
1986	0.656	0.655	0.656	0.654	0.654	0.653	0.652	0.654	0.652	0.662	0.662	0.655
1987	0.656	0.655	0.656	0.655	0.654	0.652	0.652	0.653	0.652	0.661	0.661	0.655
1988	0.655	0.654	0.655	0.655	0.654	0.652	0.651	0.653	0.651	0.660	0.660	0.654
1989	0.655	0.654	0.655	0.655	0.654	0.651	0.651	0.652	0.651	0.660	0.659	0.654
1990	0.654	0.653	0.654	0.655	0.654	0.651	0.650	0.652	0.651	0.660	0.658	0.653

TABLE 5.6 MARKET NUMBER 3 (UPPER SIND)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	42.	43.	42.	37.	41.	44.	40.	42.	42.	47.	50.	50.
1972	50.	51.	50.	44.	49.	52.	48.	50.	50.	56.	60.	60.
1973	59.	60.	59.	51.	57.	61.	56.	59.	59.	65.	70.	70.
1974	68.	69.	68.	59.	66.	71.	65.	68.	68.	75.	81.	81.
1975	78.	80.	78.	68.	77.	82.	75.	78.	78.	87.	94.	94.
1976	89.	90.	89.	77.	87.	92.	85.	89.	89.	98.	106.	106.
1977	102.	104.	102.	89.	100.	106.	98.	102.	102.	113.	122.	122.
1978	112.	114.	112.	97.	110.	117.	107.	112.	112.	124.	134.	134.
1979	116.	119.	116.	101.	114.	121.	111.	116.	116.	129.	139.	139.
1980	133.	136.	133.	116.	130.	139.	128.	133.	133.	148.	159.	159.
1981	143.	146.	143.	125.	140.	149.	137.	143.	143.	159.	171.	171.
1982	152.	155.	152.	132.	149.	159.	146.	152.	152.	169.	182.	182.
1983	162.	166.	162.	141.	159.	169.	155.	162.	162.	180.	194.	194.
1984	171.	175.	171.	149.	168.	179.	164.	171.	171.	190.	205.	205.
1985	179.	183.	179.	156.	176.	187.	172.	179.	179.	199.	215.	215.
1986	187.	191.	187.	163.	183.	195.	180.	187.	187.	208.	225.	225.
1987	196.	199.	196.	170.	190.	203.	189.	196.	196.	218.	236.	236.
1988	205.	208.	205.	178.	198.	212.	198.	205.	205.	228.	247.	247.
1989	214.	217.	214.	186.	206.	221.	208.	215.	215.	239.	259.	259.
1990	224.	226.	224.	194.	214.	230.	218.	225.	225.	250.	272.	272.

TABLE 5.7

WEST PAKISTAN INTEGRATED POWER SYSTEM - ALTERNATIVE A

MARKET DATA

MARKET NUMBER 1 (NORTHERN GRID)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	870.	930.	842.	819.	867.	769.	753.	751.	844.	880.	947.	978.
1972	969.	1035.	939.	913.	972.	858.	840.	839.	942.	983.	1056.	1096.
1973	1075.	1146.	1041.	1011.	1070.	953.	934.	932.	1047.	1091.	1171.	1208.
1974	1185.	1263.	1148.	1115.	1181.	1053.	1032.	1032.	1157.	1206.	1291.	1333.
1975	1292.	1377.	1253.	1217.	1287.	1151.	1127.	1127.	1265.	1317.	1410.	1454.
1976	1422.	1515.	1381.	1339.	1417.	1273.	1251.	1253.	1401.	1456.	1553.	1601.
1977	1564.	1663.	1521.	1473.	1558.	1410.	1386.	1391.	1551.	1608.	1708.	1762.
1978	1714.	1821.	1670.	1615.	1708.	1557.	1531.	1538.	1710.	1770.	1872.	1931.
1979	1890.	2005.	1846.	1781.	1884.	1730.	1703.	1715.	1900.	1960.	2066.	2130.
1980	2029.	2152.	1984.	1913.	2023.	1864.	1836.	1851.	2047.	2110.	2220.	2287.
1981	2199.	2329.	2154.	2073.	2193.	2033.	2003.	2023.	2231.	2295.	2407.	2479.
1982	2381.	2518.	2335.	2245.	2373.	2212.	2182.	2205.	2427.	2492.	2605.	2683.
1983	2561.	2706.	2516.	2415.	2554.	2392.	2361.	2389.	2624.	2689.	2804.	2887.
1984	2734.	2887.	2689.	2578.	2726.	2563.	2531.	2562.	2810.	2876.	2993.	3081.
1985	2897.	3058.	2852.	2732.	2889.	2724.	2692.	2727.	2987.	3056.	3173.	3266.
1986	3066.	3234.	3022.	2892.	3058.	2896.	2869.	2910.	3182.	3249.	3366.	3463.
1987	3244.	3422.	3203.	3061.	3238.	3079.	3058.	3105.	3388.	3454.	3569.	3672.
1988	3433.	3617.	3395.	3240.	3428.	3273.	3259.	3312.	3607.	3673.	3784.	3892.
1989	3633.	3825.	3597.	3428.	3629.	3479.	3472.	3533.	3839.	3904.	3906.	4126.
1990	3845.	4045.	3812.	3628.	3842.	3697.	3699.	3768.	4085.	4150.	4142.	4373.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.328	0.335	0.336	0.287	0.307	0.423	0.394	0.423	0.405	0.381	0.311	0.297
1972	0.328	0.335	0.336	0.287	0.307	0.423	0.393	0.422	0.404	0.380	0.310	0.297
1973	0.328	0.335	0.336	0.287	0.307	0.422	0.392	0.421	0.403	0.379	0.310	0.297
1974	0.328	0.335	0.336	0.287	0.307	0.408	0.391	0.419	0.402	0.378	0.310	0.296
1975	0.328	0.335	0.335	0.286	0.307	0.406	0.390	0.418	0.400	0.376	0.310	0.296
1976	0.327	0.335	0.334	0.286	0.306	0.404	0.386	0.414	0.397	0.375	0.309	0.296
1977	0.326	0.335	0.333	0.285	0.306	0.400	0.383	0.409	0.394	0.373	0.308	0.295
1978	0.326	0.335	0.332	0.285	0.305	0.397	0.379	0.405	0.391	0.371	0.308	0.295
1979	0.325	0.335	0.331	0.284	0.305	0.393	0.375	0.399	0.387	0.369	0.307	0.294
1980	0.325	0.324	0.330	0.284	0.304	0.391	0.373	0.396	0.386	0.367	0.306	0.293
1981	0.325	0.324	0.329	0.284	0.304	0.388	0.370	0.393	0.383	0.365	0.306	0.293
1982	0.324	0.324	0.328	0.283	0.303	0.386	0.367	0.390	0.380	0.364	0.305	0.293
1983	0.324	0.324	0.327	0.283	0.313	0.383	0.365	0.386	0.378	0.362	0.305	0.292
1984	0.323	0.324	0.326	0.282	0.313	0.381	0.362	0.384	0.376	0.361	0.304	0.292
1985	0.323	0.324	0.326	0.282	0.313	0.380	0.361	0.382	0.375	0.360	0.304	0.302
1986	0.323	0.324	0.325	0.282	0.313	0.378	0.359	0.379	0.373	0.358	0.303	0.301
1987	0.322	0.323	0.324	0.292	0.312	0.376	0.357	0.377	0.371	0.357	0.303	0.301
1988	0.322	0.323	0.323	0.291	0.312	0.374	0.354	0.374	0.369	0.356	0.303	0.301
1989	0.321	0.323	0.322	0.291	0.311	0.372	0.352	0.371	0.367	0.354	0.302	0.300
1990	0.321	0.323	0.322	0.291	0.311	0.370	0.350	0.369	0.365	0.353	0.302	0.300

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.661	0.664	0.689	0.587	0.665	0.833	0.799	0.846	0.815	0.771	0.633	0.611
1972	0.660	0.665	0.689	0.586	0.623	0.832	0.797	0.844	0.814	0.769	0.632	0.609
1973	0.658	0.664	0.688	0.585	0.626	0.830	0.794	0.841	0.811	0.768	0.631	0.608
1974	0.656	0.664	0.687	0.583	0.626	0.827	0.790	0.837	0.808	0.765	0.631	0.607
1975	0.655	0.663	0.686	0.581	0.624	0.824	0.789	0.835	0.806	0.763	0.629	0.605
1976	0.653	0.661	0.684	0.580	0.622	0.819	0.780	0.825	0.800	0.759	0.626	0.603
1977	0.653	0.661	0.681	0.578	0.622	0.811	0.773	0.818	0.792	0.753	0.625	0.602
1978	0.654	0.660	0.677	0.578	0.622	0.804	0.767	0.809	0.785	0.747	0.625	0.603
1979	0.655	0.659	0.673	0.577	0.623	0.796	0.760	0.799	0.775	0.740	0.623	0.602
1980	0.655	0.658	0.671	0.577	0.623	0.791	0.758	0.795	0.769	0.734	0.623	0.602
1981	0.687	0.658	0.668	0.578	0.623	0.785	0.752	0.787	0.762	0.729	0.622	0.602
1982	0.653	0.656	0.665	0.576	0.624	0.779	0.746	0.780	0.757	0.724	0.622	0.602
1983	0.652	0.656	0.662	0.578	0.624	0.773	0.740	0.773	0.751	0.720	0.622	0.602
1984	0.650	0.655	0.661	0.579	0.626	0.769	0.736	0.768	0.748	0.716	0.622	0.602
1985	0.650	0.655	0.659	0.581	0.627	0.765	0.732	0.763	0.744	0.713	0.623	0.603
1986	0.648	0.654	0.657	0.582	0.627	0.761	0.727	0.757	0.740	0.709	0.623	0.603
1987	0.648	0.653	0.654	0.583	0.628	0.756	0.721	0.751	0.735	0.705	0.623	0.603
1988	0.646	0.652	0.653	0.585	0.627	0.752	0.717	0.745	0.731	0.701	0.623	0.603
1989	0.645	0.652	0.650	0.586	0.629	0.745	0.711	0.739	0.726	0.698	0.624	0.604
1990	0.643	0.651	0.648	0.588	0.628	0.742	0.707	0.734	0.722	0.695	0.623	0.604

TABLE 5.7 - MARKET NUMBER 2 (KARACHI-LOWER SIND)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	323.	324.	327.	330.	338.	347.	348.	351.	360.	368.	359.	368.
1972	371.	372.	375.	379.	388.	399.	400.	403.	414.	422.	412.	422.
1973	424.	426.	429.	434.	444.	456.	457.	460.	473.	482.	471.	482.
1974	479.	480.	484.	489.	501.	514.	513.	517.	536.	542.	530.	543.
1975	534.	535.	540.	546.	558.	573.	571.	576.	592.	603.	590.	604.
1976	594.	595.	600.	606.	621.	637.	647.	652.	670.	682.	667.	683.
1977	670.	671.	677.	684.	700.	719.	719.	723.	744.	757.	741.	759.
1978	742.	743.	750.	757.	775.	796.	797.	802.	825.	839.	811.	842.
1979	821.	822.	828.	836.	855.	879.	866.	873.	897.	913.	893.	916.
1980	889.	890.	897.	906.	926.	952.	955.	962.	989.	1006.	984.	1010.
1981	978.	979.	985.	995.	1018.	1047.	1038.	1044.	1074.	1092.	1069.	1097.
1982	1059.	1059.	1067.	1078.	1102.	1133.	1122.	1131.	1163.	1182.	1157.	1186.
1983	1141.	1142.	1151.	1163.	1189.	1221.	1207.	1216.	1250.	1271.	1244.	1277.
1984	1224.	1224.	1234.	1246.	1274.	1310.	1291.	1300.	1336.	1359.	1330.	1374.
1985	1308.	1308.	1318.	1331.	1361.	1400.	1378.	1388.	1427.	1451.	1421.	1457.
1986	1395.	1396.	1407.	1421.	1453.	1493.	1471.	1482.	1524.	1549.	1518.	1545.
1987	1488.	1490.	1502.	1517.	1551.	1592.	1570.	1581.	1628.	1654.	1622.	1638.
1988	1587.	1590.	1603.	1620.	1656.	1698.	1676.	1688.	1739.	1766.	1733.	1737.
1989	1693.	1697.	1711.	1730.	1768.	1811.	1789.	1802.	1857.	1885.	1852.	1842.
1990	1806.	1811.	1826.	1847.	1887.	1931.	1909.	1924.	1983.	2012.	1979.	1953.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.300	0.300	0.300	0.310	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1972	0.300	0.300	0.300	0.300	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1973	0.290	0.300	0.290	0.300	0.300	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1974	0.290	0.300	0.290	0.290	0.290	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1975	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.300	0.310	0.300	0.300
1976	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290	0.310	0.300	0.300
1977	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.300
1978	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1979	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1980	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1981	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1982	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1983	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1984	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1985	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1986	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1987	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1988	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1989	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290
1990	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.660	0.662	0.661	0.665	0.670	0.663	0.665	0.658	0.664	0.668	0.666	0.667
1972	0.660	0.662	0.660	0.662	0.666	0.662	0.665	0.657	0.663	0.668	0.665	0.665
1973	0.659	0.660	0.659	0.660	0.662	0.661	0.664	0.656	0.662	0.667	0.664	0.664
1974	0.658	0.660	0.658	0.657	0.658	0.660	0.663	0.654	0.661	0.667	0.663	0.662
1975	0.658	0.658	0.657	0.654	0.654	0.657	0.662	0.653	0.660	0.666	0.662	0.661
1976	0.657	0.657	0.657	0.652	0.650	0.655	0.660	0.652	0.658	0.665	0.662	0.660
1977	0.657	0.657	0.657	0.652	0.650	0.655	0.659	0.652	0.657	0.665	0.663	0.660
1978	0.658	0.657	0.658	0.651	0.651	0.655	0.658	0.653	0.656	0.666	0.663	0.659
1979	0.658	0.658	0.658	0.651	0.651	0.655	0.657	0.654	0.655	0.666	0.664	0.659
1980	0.659	0.658	0.659	0.650	0.652	0.655	0.656	0.655	0.655	0.667	0.664	0.658
1981	0.659	0.658	0.659	0.650	0.653	0.655	0.655	0.656	0.654	0.667	0.665	0.658
1982	0.658	0.657	0.658	0.651	0.653	0.655	0.654	0.656	0.654	0.666	0.665	0.657
1983	0.658	0.657	0.658	0.651	0.654	0.654	0.654	0.655	0.654	0.665	0.664	0.657
1984	0.657	0.656	0.657	0.652	0.654	0.654	0.653	0.655	0.653	0.664	0.664	0.656
1985	0.657	0.656	0.657	0.653	0.654	0.653	0.653	0.654	0.653	0.663	0.663	0.656
1986	0.656	0.655	0.656	0.654	0.654	0.653	0.652	0.654	0.652	0.662	0.662	0.655
1987	0.656	0.655	0.656	0.655	0.654	0.652	0.652	0.653	0.652	0.661	0.661	0.655
1988	0.655	0.654	0.655	0.655	0.654	0.652	0.651	0.653	0.651	0.660	0.660	0.654
1989	0.655	0.654	0.655	0.655	0.654	0.651	0.651	0.652	0.651	0.660	0.659	0.654
1990	0.654	0.653	0.654	0.655	0.654	0.651	0.650	0.652	0.651	0.660	0.658	0.653

TABLE 5.7 - MARKET NUMBER 3 (UPPER SIND)
PMAX (MW)

MU =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	42.	43.	42.	37.	41.	44.	40.	42.	42.	47.	50.	50.
1972	[illegible]	51.	50.	44.	49.	52.	48.	50.	50.	56.	60.	60.
1973	59.	60.	59.	51.	57.	61.	56.	59.	59.	65.	70.	70.
1974	68.	69.	68.	59.	66.	71.	65.	68.	68.	75.	81.	81.
1975	73.	[illegible]	78.	68.	77.	82.	75.	78.	78.	87.	94.	94.
1976	89.	[illegible]	89.	77.	87.	92.	85.	89.	89.	98.	106.	106.
1977	102.	104.	102.	89.	100.	106.	98.	102.	102.	113.	122.	122.
1978	112.	114.	112.	97.	110.	117.	107.	112.	112.	124.	134.	134.
1979	116.	119.	116.	101.	114.	121.	111.	116.	116.	129.	139.	139.
1980	133.	136.	133.	116.	130.	139.	128.	133.	133.	148.	159.	159.
1981	143.	146.	143.	125.	140.	149.	137.	143.	143.	159.	171.	171.
1982	152.	155.	152.	132.	149.	159.	146.	152.	152.	169.	182.	182.
1983	162.	166.	162.	141.	159.	169.	155.	162.	162.	180.	194.	194.
1984	171.	175.	171.	149.	168.	179.	164.	171.	171.	190.	205.	205.
1985	179.	183.	179.	156.	176.	187.	172.	179.	179.	199.	215.	215.
1986	187.	191.	187.	163.	183.	195.	180.	187.	187.	208.	225.	225.
1987	196.	199.	196.	170.	190.	203.	189.	196.	196.	213.	236.	236.
1988	205.	208.	205.	178.	198.	212.	198.	205.	205.	226.	247.	247.
1989	214.	217.	214.	186.	206.	221.	208.	215.	215.	239.	259.	259.
1990	224.	228.	224.	194.	214.	230.	218.	225.	225.	[illegible]	272.	272.

TABLE 5.8

WEST PAKISTAN INTEGRATED POWER SYSTEM - ALTERNATIVE B

MARKET DATA

MARKET NUMBER 1 (NORTHERN GRID)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	884.	934.	872.	834.	882.	832.	821.	830.	909.	928.	966.	995.
1972	985.	1040.	972.	929.	987.	928.	916.	927.	1014.	1036.	1077.	1109.
1973	1093.	1152.	1077.	1029.	1088.	1030.	1017.	1029.	1125.	1150.	1194.	1229.
1974	1204.	1269.	1187.	1135.	1201.	1137.	1122.	1137.	1243.	1270.	1317.	1356.
1975	1313.	1384.	1296.	1238.	1309.	1241.	1225.	1241.	1357.	1386.	1437.	1478.
1976	1444.	1522.	1427.	1362.	1440.	1370.	1355.	1374.	1499.	1529.	1582.	1627.
1977	1588.	1671.	1570.	1497.	1583.	1513.	1497.	1520.	1655.	1685.	1739.	1789.
1978	1739.	1829.	1722.	1641.	1734.	1665.	1648.	1674.	1820.	1851.	1905.	1960.
1979	1917.	2014.	1901.	1808.	1912.	1845.	1826.	1858.	2016.	2047.	2101.	2160.
1980	2057.	2160.	2042.	1942.	2052.	1984.	1966.	2001.	2169.	2200.	2256.	2319.
1981	2229.	2338.	2214.	2103.	2223.	2159.	2139.	2180.	2358.	2389.	2445.	2512.
1982	2412.	2527.	2398.	2276.	2405.	2343.	2323.	2369.	2560.	2590.	2645.	2718.
1983	2594.	2716.	2581.	2448.	2587.	2529.	2508.	2560.	2762.	2792.	2845.	2923.
1984	2767.	2897.	2757.	2612.	2760.	2705.	2684.	2739.	2953.	2983.	3036.	3119.
1985	2932.	3068.	2922.	2767.	2924.	2871.	2851.	2911.	3136.	3166.	3218.	3305.
1986	3102.	3245.	3095.	2928.	3095.	3047.	3032.	3099.	3334.	3362.	3411.	3503.
1987	3281.	3433.	3277.	3098.	3276.	3234.	3225.	3299.	3544.	3570.	3615.	3712.
1988	3471.	3628.	3471.	3278.	3466.	3432.	3430.	3510.	3767.	3791.	3832.	3934.
1989	3672.	3837.	3675.	3467.	3668.	3642.	3647.	3736.	4002.	4026.	3955.	4169.
1990	3885.	4057.	3892.	3668.	3882.	3863.	3878.	3975.	4252.	4274.	4192.	4417.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.363	0.345	0.407	0.326	0.343	0.576	0.564	0.618	0.549	0.489	0.354	0.334
1972	0.363	0.345	0.407	0.326	0.343	0.575	0.562	0.614	0.548	0.487	0.353	0.333
1973	0.362	0.345	0.406	0.326	0.343	0.571	0.558	0.610	0.545	0.484	0.353	0.333
1974	0.362	0.345	0.406	0.325	0.343	0.558	0.557	0.607	0.542	0.482	0.351	0.332
1975	0.362	0.345	0.404	0.324	0.342	0.555	0.555	0.605	0.540	0.480	0.351	0.332
1976	0.361	0.345	0.402	0.323	0.341	0.548	0.546	0.593	0.532	0.475	0.349	0.330
1977	0.359	0.344	0.399	0.321	0.339	0.539	0.535	0.581	0.523	0.469	0.346	0.328
1978	0.357	0.344	0.395	0.319	0.338	0.531	0.526	0.570	0.516	0.463	0.345	0.326
1979	0.355	0.343	0.391	0.317	0.335	0.520	0.516	0.557	0.506	0.456	0.342	0.324
1980	0.355	0.333	0.389	0.316	0.335	0.516	0.510	0.551	0.501	0.453	0.341	0.323
1981	0.353	0.333	0.386	0.315	0.333	0.508	0.502	0.543	0.495	0.448	0.339	0.322
1982	0.351	0.333	0.383	0.313	0.331	0.501	0.494	0.532	0.488	0.443	0.337	0.320
1983	0.350	0.332	0.381	0.312	0.340	0.495	0.487	0.524	0.482	0.439	0.336	0.319
1984	0.349	0.332	0.378	0.310	0.340	0.490	0.482	0.518	0.477	0.435	0.335	0.318
1985	0.348	0.332	0.377	0.310	0.339	0.486	0.477	0.513	0.473	0.433	0.333	0.327
1986	0.347	0.331	0.374	0.309	0.337	0.481	0.471	0.505	0.468	0.428	0.332	0.326
1987	0.346	0.330	0.372	0.317	0.336	0.475	0.465	0.498	0.462	0.425	0.331	0.325
1988	0.345	0.330	0.370	0.316	0.335	0.470	0.459	0.491	0.457	0.421	0.329	0.323
1989	0.344	0.330	0.368	0.315	0.334	0.464	0.453	0.480	0.452	0.417	0.329	0.322
1990	0.343	0.330	0.365	0.314	0.333	0.459	0.447	0.477	0.447	0.414	0.328	0.321

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.650	0.661	0.666	0.577	0.617	0.770	0.733	0.766	0.757	0.731	0.620	0.600
1972	0.649	0.662	0.666	0.576	0.614	0.770	0.731	0.764	0.756	0.730	0.620	0.599
1973	0.647	0.660	0.665	0.575	0.615	0.768	0.729	0.762	0.755	0.729	0.619	0.598
1974	0.646	0.661	0.664	0.573	0.615	0.766	0.727	0.759	0.752	0.726	0.618	0.596
1975	0.645	0.659	0.663	0.571	0.614	0.765	0.726	0.758	0.751	0.725	0.617	0.595
1976	0.643	0.658	0.662	0.570	0.612	0.761	0.720	0.753	0.747	0.723	0.615	0.593
1977	0.643	0.658	0.659	0.569	0.612	0.755	0.716	0.748	0.742	0.719	0.614	0.593
1978	0.645	0.657	0.657	0.569	0.613	0.751	0.713	0.743	0.737	0.714	0.614	0.594
1979	0.645	0.656	0.654	0.568	0.614	0.746	0.709	0.639	0.730	0.719	0.613	0.594
1980	0.646	0.656	0.652	0.569	0.615	0.743	0.707	0.736	0.726	0.705	0.613	0.593
1981	0.646	0.655	0.649	0.569	0.615	0.739	0.705	0.731	0.721	0.700	0.612	0.594
1982	0.645	0.654	0.648	0.569	0.616	0.736	0.701	0.726	0.718	0.696	0.613	0.594
1983	0.644	0.654	0.646	0.570	0.616	0.732	0.697	0.721	0.714	0.693	0.613	0.595
1984	0.643	0.653	0.645	0.572	0.618	0.729	0.694	0.718	0.712	0.690	0.613	0.595
1985	0.642	0.653	0.643	0.573	0.620	0.726	0.691	0.715	0.709	0.688	0.614	0.596
1986	0.641	0.651	0.642	0.575	0.619	0.723	0.688	0.711	0.706	0.685	0.614	0.596
1987	0.640	0.651	0.640	0.576	0.621	0.720	0.684	0.707	0.702	0.682	0.614	0.597
1988	0.639	0.650	0.638	0.578	0.620	0.717	0.681	0.703	0.700	0.679	0.615	0.597
1989	0.638	0.650	0.636	0.580	0.622	0.712	0.677	0.699	0.696	0.676	0.616	0.598
1990	0.636	0.649	0.635	0.581	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE 5.8 - MARKET NUMBER 2 (KARACHI-LOWER SIND)

PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	323.	324.	327.	330.	338.	347.	348.	351.	360.	368.	359.	368.
1972	371.	372.	375.	379.	388.	399.	400.	403.	414.	422.	412.	422.
1973	424.	426.	429.	434.	444.	456.	457.	460.	473.	482.	471.	482.
1974	479.	480.	484.	489.	501.	514.	513.	517.	536.	542.	530.	543.
1975	534.	535.	540.	546.	558.	573.	571.	576.	592.	603.	590.	604.
1976	594.	595.	600.	606.	621.	637.	647.	652.	670.	682.	667.	683.
1977	670.	671.	677.	684.	700.	719.	719.	723.	744.	757.	741.	759.
1978	742.	743.	750.	757.	775.	796.	797.	802.	825.	839.	811.	842.
1979	821.	822.	828.	836.	855.	879.	866.	873.	897.	913.	893.	916.
1980	889.	890.	897.	906.	926.	952.	955.	962.	989.	1006.	984.	1010.
1981	978.	979.	985.	995.	1018.	1047.	1038.	1044.	1074.	1092.	1069.	1097.
1982	1059.	1059.	1067.	1078.	1102.	1133.	1122.	1131.	1163.	1182.	1157.	1186.
1983	1141.	1142.	1151.	1163.	1189.	1221.	1207.	1216.	1250.	1271.	1244.	1277.
1984	1224.	1224.	1234.	1246.	1274.	1310.	1291.	1300.	1336.	1359.	1330.	1374.
1985	1308.	1308.	1318.	1331.	1361.	1400.	1378.	1388.	1427.	1451.	1421.	1457.
1986	1395.	1396.	1407.	1421.	1453.	1493.	1471.	1482.	1524.	1549.	1518.	1545.
1987	1488.	1490.	1502.	1517.	1551.	1592.	1570.	1581.	1628.	1654.	1622.	1638.
1988	1587.	1590.	1603.	1620.	1656.	1698.	1676.	1688.	1739.	1766.	1733.	1737.
1989	1693.	1697.	1711.	1730.	1768.	1811.	1789.	1802.	1857.	1885.	1852.	1842.
1990	1806.	1811.	1826.	1847.	1887.	1931.	1909.	1924.	1983.	2012.	1979.	1953.

PMIN (RATIO OF MINIMUM TO MAXIMUM LOAD)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.300	0.300	0.300	0.310	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1972	0.300	0.300	0.300	0.300	0.310	0.300	0.310	0.290	0.300	0.310	0.310	0.310
1973	0.290	0.300	0.290	0.300	0.300	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1974	0.290	0.300	0.290	0.290	0.290	0.300	0.300	0.290	0.300	0.310	0.300	0.300
1975	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.300	0.310	0.300	0.300
1976	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290	0.310	0.300	0.300
1977	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.300
1978	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1979	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1980	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1981	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1982	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.310	0.300	0.290
1983	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1984	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1985	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1986	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1987	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1988	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.300	0.290
1989	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290
1990	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.290	0.300	0.290	0.290

LOAD FACTOR

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	0.660	0.662	0.661	0.665	0.670	0.663	0.665	0.658	0.664	0.668	0.666	0.667
1972	0.660	0.662	0.660	0.662	0.666	0.662	0.665	0.657	0.663	0.668	0.665	0.665
1973	0.659	0.660	0.659	0.660	0.662	0.661	0.664	0.656	0.662	0.667	0.664	0.664
1974	0.658	0.660	0.658	0.657	0.658	0.660	0.663	0.654	0.661	0.667	0.663	0.662
1975	0.658	0.658	0.657	0.654	0.654	0.657	0.662	0.653	0.660	0.666	0.662	0.661
1976	0.657	0.657	0.657	0.652	0.650	0.655	0.660	0.652	0.658	0.665	0.662	0.660
1977	0.657	0.657	0.657	0.652	0.650	0.655	0.659	0.652	0.657	0.665	0.663	0.660
1978	0.658	0.657	0.658	0.651	0.651	0.655	0.658	0.653	0.656	0.666	0.663	0.659
1979	0.658	0.658	0.658	0.651	0.651	0.655	0.657	0.654	0.655	0.666	0.664	0.659
1980	0.659	0.658	0.659	0.650	0.652	0.655	0.656	0.655	0.655	0.667	0.664	0.658
1981	0.659	0.658	0.659	0.650	0.653	0.655	0.655	0.656	0.654	0.667	0.665	0.658
1982	0.658	0.657	0.658	0.651	0.653	0.655	0.654	0.656	0.654	0.666	0.665	0.657
1983	0.658	0.657	0.658	0.651	0.654	0.654	0.654	0.655	0.654	0.665	0.664	0.657
1984	0.657	0.656	0.657	0.652	0.654	0.654	0.653	0.655	0.653	0.664	0.664	0.656
1985	0.657	0.656	0.657	0.653	0.654	0.653	0.653	0.654	0.653	0.663	0.663	0.656
1986	0.656	0.655	0.656	0.654	0.654	0.653	0.652	0.654	0.652	0.662	0.662	0.655
1987	0.656	0.655	0.656	0.655	0.654	0.652	0.652	0.653	0.652	0.661	0.661	0.655
1988	0.655	0.654	0.655	0.655	0.654	0.652	0.651	0.653	0.651	0.660	0.660	0.654
1989	0.655	0.654	0.655	0.655	0.654	0.651	0.651	0.652	0.651	0.660	0.660	0.654
1990	0.654	0.653	0.654	0.655	0.654	0.651	0.650	0.652	0.651	0.660	0.658	0.653

TABLE 5.8 - MARKET NUMBER 3 (UPPER SIND)
PMAX (MW)

MO =	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1971	42.	43.	42.	37.	41.	44.	40.	42.	42.	47.	50.	50.
1972	50.	51.	50.	44.	49.	52.	48.	50.	50.	56.	60.	60.
1973	59.	60.	59.	51.	57.	61.	56.	59.	59.	65.	70.	70.
1974	68.	69.	68.	59.	66.	71.	65.	68.	68.	75.	81.	81.
1975	78.	80.	78.	68.	77.	82.	75.	78.	78.	87.	94.	94.
1976	89.	90.	89.	77.	87.	92.	85.	89.	89.	98.	106.	106.
1977	102.	104.	102.	89.	100.	106.	98.	102.	102.	113.	122.	122.
1978	112.	114.	112.	97.	110.	117.	107.	112.	112.	124.	134.	134.
1979	116.	119.	116.	101.	114.	121.	111.	116.	116.	129.	139.	139.
1980	133.	136.	133.	116.	130.	139.	128.	133.	133.	148.	159.	159.
1981	143.	146.	143.	125.	140.	149.	137.	143.	143.	159.	171.	171.
1982	152.	155.	152.	132.	149.	159.	146.	152.	152.	169.	182.	182.
1983	162.	166.	162.	141.	159.	169.	155.	162.	162.	180.	194.	194.
1984	171.	175.	171.	149.	168.	179.	164.	171.	171.	190.	205.	205.
1985	179.	183.	179.	156.	176.	187.	172.	179.	179.	199.	215.	215.
1986	187.	191.	187.	163.	183.	195.	180.	187.	187.	208.	225.	225.
1987	196.	199.	196.	170.	190.	203.	189.	196.	196.	218.	236.	236.
1988	205.	208.	205.	178.	198.	212.	198.	205.	205.	228.	247.	247.
1989	214.	217.	214.	186.	206.	221.	208.	215.	215.	239.	259.	259.
1990	224.	226.	224.	194.	214.	230.	218.	225.	225.	250.	272.	272.

TABLE 5.9

PROJECTED PRIVATE TUBEWELL GROWTH 1970 - 1975

('000 wells)

year	Mid-1970	Mid-1974		Mid-1975	
		3,000 public tubewells case	7,000 public tubewells case	3,000 public tubewells case	7,000 public tubewells case
Peshawar Region	1.1	1.3	1.3	1.4	1.4
Lahore Region	75.3	98.0	94.0	102.6	97.4
Hyderabad Region	4.6	10.7	10.5	12.0	11.7
West Pakistan	81.0	110.0	105.8	116.0	110.5

Source: Sir Alexander Gibb & Partners and Associates, Report of Indus Basin Mission June 1970, P. 270.

5.37 To interpret correctly the computer simulations the limitations of the World Bank's (Jacoby) model, which has been described in Volume III (Background and Methodology) Water and Power Resources of West Pakistan, by Pieter Lieftinck and Associates, are critically important. The benchmark for the calculations is provided by the expansion program outlined to the year 1985 by the Harza projections given in Tables B-4, C-4 and C-5 of Annex 7 and the modifications for the early years provided in the excerpt from the Fourth Five-year Plan document in Annex 3. A summary of the development of the system to 1990 was given earlier by Table 5.2. The expansion program for 1985-90, which the computer program requires, has been arbitrarily sketched with nuclear and conventional thermal capacity.

5.38 The benchmark hydrological data, the cost data associated with each installation and projected installation, and the assumed shapes of the load curves are those which have been used earlier in the Bank's own computer simulations of the West Pakistan power systems. Only very minor editing of these data was undertaken, although the passage of time undoubtedly calls for major revisions of most cost estimates. It is for these reasons that estimates of dollar figures stemming from the computer program are considered particularly unreliable, and are not presented in this report. Relative cost savings may be of somewhat greater reliability.

5.39 Assuming the benchmark basic investment strategy, outlined in Table 5.2, one may calculate the fuel cost savings resulting from pricing strategies A and B. Using the Bank's central estimate with regard to the cost of fuel, one obtains a 7.0% fuel cost saving from plan A and a 6.4% fuel cost saving as a result of plan B as an average over the 11 calendar years 1971-81. The model thus does not discriminate sharply in fuel cost saving between the two sets of alternative tubewell demand estimates. For some of the years A is reported to be slightly more economical than B, for other years it is the other way around. During the first five years, the fuel cost savings of each of the two plans amount to about 4.1%. As the interconnection of all of West Pakistan is completed and Tarbela units are installed the fuel cost savings relative to the benchmark fuel cost for plan A over the next 6 years average 11% and for plan B 9.5%. The fuel cost savings for the decade of the eighties continue, but it does not seem necessary here to go into detail. The relative fuel cost savings do not seem sensitive to which of the Bank's fuel cost figures are used.

5.40 The fuel cost savings are only part of the story. There can also be capital cost savings. Clearly by reducing monthly peaks through pricing strategies A or B, the benchmark expansion program either creates additional reserve capacity and/or makes possible modifications resulting in the saving of capital costs. In Table 5.10 are shown the reserves created through the calendar year 1982 from the adoption of tariff plans A & B relative to the basic expansion plan. If roughly 200 MW per year are on average to be added to the West Pakistan system over the coming twelve years, plan A might make possible a postponement of the expansion plan by half a year or a saving of somewhat more than 100 MW indefinitely. For plan B the capital cost savings would be less -- about two-thirds of those from plan A. The magnitude of the savings does not continue to increase rapidly because the tubewell demand forecast beyond 1975 assumes a falling off in the rate of growth of private tubewell load (see Annex 7). A sketch of the capacity savings can be obtained by comparing maximum demand forecasts for plan A and plan B with the basic benchmark forecast during critical months. The critical months for the decade of the 'seventies start in March and move to April and May by the beginning of the decade of the 'eighties. By the end of the 'eighties, as Mangla and Tarbela become relatively less significant and private tubewell loads become a smaller share of total loads, the winter months could well become critical.

TABLE 5.10

RESERVES CREATED* FROM ADOPTION OF TARIFF PLANS A AND B IN COMPARISON TO THE BASIC BENCHMARK EXPANSION PROGRAM

Year	Reserves in MW Plan A	Plan B
1971	102	72
1972	113	80
1973	124	88
1974	136	97
1975	147	104
1976	158	112
1977	76	41
1978	92	47
1979	92	67
1980	96	70
1981	94	73
1982	98	70
Arithmetic Mean	120	77

* Increases in reserves are obtained by subtracting for each year from the calculated reserve under plan A and plan B during the critical month (March, April or May) the calculated reserve under the basic program for its critical month.

5.41 No attempt is made here to price closely the fuel and capital savings. The cost data available for this study are simply too rough. A sketch of metering costs associated with the introduction of tariff types A and B for tubewells is provided in Tables 5.11, 5.12 and 5.13. The metering costs can be broken down into two parts. The first consists of replacing the meters for private tubewells existing in 1970, and the second consists of installing alternative meters rather than those of existing types for the roughly 80,000 additional private tubewells projected to be electrified in 1990. 1/

1/ 1990 is taken as the planning horizon, and the present discounted value of metering cost for the tubewells expected for years subsequent to 1990 becomes quite small.

TABLE 5.11

METERING COST CALCULATION FOR PRIVATE TUBEWELLS

(US$)

	No.	Price per tubewell	Total Price (Thousands)
Type II Meter*			
Existing supply (1970)	34,400+	52.80ϕ	1,816
New supply (1970-1990)	29,169+	16.80⌘	490
Total Cost			2,306
Type III Meter*			
Existing supply (1970)	34,400+	41.88ϕ	1,440
New supply (1970-1990)	29,169+	5,88*	172
Total Cost			1,612

* See Table 5.12

\+ See Table 5.13

ϕ Purchase price only, salvage value and labor cost assumed to balance out.

⌘ Purchase price difference between Meter Type II, III and Meter Type I.

TABLE 5.12

PURCHASE PRICE OF METERING FOR PRIVATE TUBEWELL TARIFFS

(US$)

Type	Description	Price per tubewell supply Ł	US$
I	Existing Metering	15	36.00
II	2-Register, Single-Phase, Time of Day	22	52.80
III	Single-Register, Single-Phase, Time of Day	17.45	41.88

TABLE 5.13

ESTIMATED NUMBER OF PRIVATE TUBEWELLS AND NEW ADDITIONS DISCOUNTED AT 12% PER ANNUM TO JANUARY 1970

Year	Number of Electric Private Tubewell	Increases Per Annum	Discount Factor (12%)
Jan. 1970	34,400		
1971	38,500	4100 x .893 =	3661
1972	42,800	4300 x .797 =	3427
1973	47,100	4300 x .712 =	3061
1974	51,600	4500 x .636 =	2862
1975	56,000	4400 x .567 =	2495
1976	60,200	4200 x .501 =	2104
1977	64,000	3800 x .452 =	1717
1978	67,800	3800 x .404 =	1535
1979	71,600	3800 x .361 =	1371
1980	75,400	3800 x .322 =	1224
1981	79,000	3600 x .287 =	1033
1982	82,400	3400 x .257 =	874
1983	85,900	3500 x .229 =	802
1984	89,400	3500 x .205 =	718
1985	92,800	3400 x .183 =	622
1986	95,700	2900 x .163 =	473
1987	98,100	2400 x .146 =	350
1988	100,500	2400 x .130 =	312
1989	102,900	2400 x .116 =	278
1990	105,300	2400 x .104 =	250
Total Discounted Additions			29,169

5.42 For this calculation three types of meters are considered (see Chapter 6 for details). The existing meter (Type I) priced at £15, a two-register, single-phase, time-of-day meter (Type II) at £22 and a single-register, 1/ single-phase, time-of-day meter (Type III) at £17.45. The prices are estimates of the cost of such meters from a supplier in the U.K. in 1970. The purchase prices for the hardware are likely to be subject to quantity discounts and, indeed, prices may be lower for hardware produced elsewhere.

5.43 Discounting future costs at 12% per annum, assuming labor costs of replacing existing meters to be matched by salvage costs of the existing meters, and ignoring installation costs of meters since they are about the

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1/ This single-register meter would apply a price differential by charging zero price for certain hours, i.e. the meter would then be stopped.

same regardless of the meter type, one obtains as estimates of present value of additional metering costs US$1.6 to US$2.3 million at a dollar/pound-sterling exchange rate of 2.40.

5.44 If one neglects fuel cost savings from plans A or B, which the computer simulation suggests can be substantial, and one postulates an arbitrary annual capacity saving of 50 MW per year for twenty years, an underestimate from the average savings in reserves from plan A over the first 12 years by 70 MW and an underestimate by 27 MW of the savings in reserves from plan B, one obtains at a 12% discount rate an equivalent current capacity saving of 45 MW. 1/ At estimated costs of around US$400 per kW at the official exchange rate for the first 420 MW of the Gudu thermal power station now partially under construction this most conservative evaluation of benefits relative to costs is 8 or 11 to one, depending on which meters are used. 2/ No closer costing of fuel cost savings seems necessary to demonstrate that if metering and associated tariffs can be enforced in the West Pakistan social and political environment, the cost savings promise to be very substantial indeed.

Tubewell Tariff Experiments

5.45 The analyses of private tubewell demands and of the possible benefits from time-of-day tariffs call for some specific experiments by WAPDA as a next step. It is recommended that WAPDA undertake an experiment involving private tubewell customers. Tubewell customers taking their supply from especially selected 11-kV feeders should be offered the opportunity to be billed on an optional time-of-day tariff. The object of the experiment is to discover (a) whether, in fact, the consumers would adjust their consumption patterns when provided with the appropriate incentives, (b) how their consumption would respond to specific tariffs, and (c) whether the tariff and the associated metering can be made to work in West Pakistan, given sufficient staff and attention.

1/ $$\sum_{1}^{20}(.12 \times 50) / (1.12)^t = \sum_{1}^{20} 6/(1.12)^t = 6/.12 - 6(1.12)^{-20}/ .12$$

$$= 45 \text{ MW}$$

2/ According to WAPDA September 1969 estimates (P.C.I. Proforma), the first 420 MW at the Gudu thermal power station would cost PRs 788 million. At the official 4.76 = US$1.00 exchange rate this is close to US$400 per kW. Of this total 47% requires foreign exchange. The correct value of the Pakistan rupee for economic decision making is substantially lower. But even if 100% of the additional metering costs require foreign exchange, the tubewell tariff proposals seem economical by a very considerable margin.

5.46 Feeders should be selected having a high concentration of private tubewell loads. This will allow comparison, month-by-month, of the hourly logs maintained at the grid station of the kWh sent out on a feeder after the experiment has commenced with the hourly kWh readings for the feeder during corresponding months in the previous year before the experimental tariff was in effect. It would also allow day-by-day comparison of log sheets for tubewell feeders where customers are allowed to participate in the experiment with those for similar feeders where customers are not participating.

5.47 The precise characteristics of the experimental tariff should be worked out by WAPDA officials with a view toward the public relations problems to be anticipated. But the basic purpose of the tariff design should be to ensure that a high percentage of customers on the selected feeders will choose the tariff. The level of the experimental rates, therefore, needs to be made attractive in relation to existing rates, and not much concern should be given to the level of rates ultimately to prevail for tubewell customers if the results of the experiment prove promising.

5.48 One possibility for the experimental tariff would be the fixed charge currently in effect, but with the kWh charge equal to zero, except during the hours from 4:30 to 9:00 p.m. During these critical evening hours the kWh charge would continue in effect or, if there are fears of the public relations or precedent-setting aspects of the tariff, the energy charge during the critical hours could be increased by, say, 50% or even 100% over that currently in effect for all 24 hours. Such a surcharge would still appear to give the tubewell customer substantial opportunities to lower his monthly electricity bills and therefore encourage him to choose the optional tariff after obtaining careful and complete explanation from WAPDA officials of the advantages to be derived from this choice. This version of the experiment would require a single-register, single-phase, time-of-day meter complete with timeswitch (Type III, Table 5.12), costing between £17 and £18 in the U.K.

5.49 A slightly more complicated experimental tariff would involve, say, the same fixed charge as is now in effect, with an energy charge during the off-peak hours higher than zero. To ensure that tubewell customers selected for the experiment would generally choose the new tariff over the old, the enhanced rate for energy during peak hours might be 50% higher than that currently in effect and say 50% lower during other hours. But even substantially higher surcharges relative to existing energy charges could seem attractive if the high-priced period were of sufficiently short duration. This version of the experiment would, of course, require installation of the double-register meter, referred to above as the Type II meter, estimated to cost around £22 in the U.K.

5.50 To undertake the experiment successfully, sufficient personnel must be assigned to explain the tariff, to monitor closely the metering of those who chose the experimental tariff and (perhaps especially) of those who do not, and to analyze the results. The experiment probably should take a minimum of twelve months, and it should be understood that changed tubewell utilization patterns require some learning and adaptation to time-of-day tariffs before their full consequences show up on the grid station log sheets. It is recommended that the experiment receive high level supervision within WAPDA. Perhaps an Assistant Director of Planning, on equal footing with the Director of the Power Market Survey and reporting directly to the Director of Planning, should be given the responsibility for the overall conduct of the experiment, although WAPDA might see fit to place responsibility for it elsewhere in the organization at a similar responsible level.

WAPDA Reorganization

5.51 With the break-up of West Pakistan as of July 1, 1970, into its component provinces, there has come much speculation on the consequences of this for the WAPDA power organization. This study, of course, does not make any recommendations for appropriate reorganization, if any, for WAPDA. The study would be remiss to ignore completely the possibility that (a) WAPDA as a whole be divided into separate but interconnected provincial power generating, transmission and distribution companies, or (b) WAPDA's distribution system might be separated from WAPDA's generation and transmission system and formed into independent provincial energy retailing organizations. In either of these eventualities it would be of utmost importance that bulk power for sale in the wholesale market for electricity be sold at prices reflecting costs at the time that energy is transferred from one organization to the other. Indeed, if a WAPDA furcated into separate power generation systems is not to lead to substantial inefficiency in the development of generation facilities, careful costing of transfers of power from one organization to another becomes of the essence. Pricing that would fail in transmitting cost messages could lead to the development of smaller and more costly generating facilities in each province rather than of those facilities that minimize costs for all of West Pakistan. Similarly, in separating distribution in each province from an integrated WAPDA generation and transmission company, appropriately fluctuating wholesale prices for power can become important instruments for transmitting the generating cost messages through the retail power companies to the final consumers. The retailer will be encouraged to pass on both high costs and low costs in correspondingly high and low costs to his customers.

5.52 In the United States there is considerable experience with pricing wholesale power within power pools, and in England and Wales with pricing power to retailing organizations. Any planning of the reorganization of WAPDA along one line or the other requires that the very closest attention be paid to the advantages to be had from seasonal and time-of-day pricing. It should be added that considerable technical problems need to be solved if large blocks of power transferred in the wholesale market are to be properly metered.

6. HARDWARE FOR ELECTRICITY PRICING

General Principles

6.01 The purpose of this chapter is to set out the various items of hardware, notably electricity meters, which are, or could be, used for electricity pricing. The explanations are mainly in terms of what the hardware does and the performance limitations rather than how the duty is performed in terms of gear trains. However non-technical readers need some insight into the complexity or otherwise of the various items to form a view as to the immediate feasibility of application of more complex metering in developing countries such as West Pakistan. In explaining what the hardware does in terms of tariff pressures or pricing, approval of that kind of pricing from an economic viewpoint should not be assumed. The aim is to catalog what could be done instead of arguing whether it should be done.

6.02 In principle any electrical quantity however complex the definition can be metered, but at a price. Electricity meters are remarkably versatile. This ability is likely however to be severely curtailed in developing countries by the lack of suitable test and maintenance facilities, and by the absence of local experts trained in the installation and maintenance of small mechanisms and electronics. Equally the usual practice of manufacturing such hardware in remote countries hampers dialogue between the user and the manufacturer. This dialogue, if it could conveniently take place, would lead in time to installation practices and meter designs better suited to the developing country concerned.

6.03 Again there are facets of the environment of West Pakistan which are clearly inimical to metering. These are high temperatures, strong sunlight, dust, tampering and poor voltage and frequency regulation. However, little is to be gained by focusing attention only on the difficulties likely to be experienced. More positive thinking suggests that the procedure should be to make a preliminary choice of metering for any new electricity tariff, to gauge the benefits likely to arise, and with these benefits in mind to assess the cost of resources necessary to make the hardware work successfully even in an inimical environment. Of course, the costs might then turn out to exceed the benefits. However, the reasonable expectation is that some of these costs will fall in time as developing countries grow more expert in meter engineering.

6.04 The cost of metering a novel electricity tariff includes the development costs of the hardware, tooling costs, especially the press tools for plastic casings and working parts, the cost of overcoming teething troubles and the cost of training staff and providing test equipment. If the requirement that the hardware should be specifically adapted to the environment be set on one side, some items can be purchased fairly easily from a very limited number of suppliers. This facility depends upon the frequency of batch production of the items and hence upon the demands made by other customers. Generally speaking, only the standard items of hardware used in popular tariff structures are likely to be available out of a manufacturer's stock or, since stocks are rarely held, out of the batch currently in production.

6.05 Quite small changes in the design, as suggested by the customer, are likely to have a surprising and unhelpful impact on the price, delivery time and freedom from teething troubles. Particular difficulties will arise when a request is made for a quotation covering a small number of meters of an unusual design. Under such circumstances, the manufacturer might well expect to be assured of repeat orders and, in addition, may expect a share of orders for standard designs. Such considerations should be borne in mind when discussing the price of hardware; as the market becomes more specialized, the "price" becomes less meaningful.

6.06 Some of the adaptation to environment could take the form of protective boxes which leave the meter itself unmodified. In Chapter 3 boxes have been illustrated which seek to prevent pilferage but which also help to keep dust out of the mechanism. Plastic gear chains, nowadays in widespread use, are particularly affected by a combination of direct sunlight and high temperatures. One solution is to mount the protective box in the shade of a building. Another is to provide a (metal) sunshade with an air gap between the shade and the box.

6.07 Poor voltage and frequency regulation hinder differential pricing. Once the simple single-register meter is superseded by almost any form of meter for differential pricing, miniature synchronous motors are almost certain to be a component of the meter and its time control. These low-cost items rotate at a fixed speed governed by the supply frequency, or not at all, and hence provide the time scale for most time-rate or time-incidence pricing of electricity. In addition to their dependence on the accuracy of system frequency control, they are more likely to adopt the zero-speed mode when the voltage is low. For a 240 V system, 1/ the permissible range of variation that keeps the motor in synchronism extends from 270 V down to 180 V. This range is about as far as designs can be stretched.

6.08 The ability of the meter disc to rotate at a speed proportional to the rate of using energy is not significantly affected by poor voltage and frequency regulation. Given only a little care in testing, transport and installation, the usual rotating disc meter is capable of remarkable accuracy, measuring energy to within a few per cent, with loads ranging from full load to as low as one-fortieth of full load. The accuracy is also maintained over very many years in temperate climates.

1/ Manufacturers usually ask what is the nominal voltage and have been known to express surprise when the equipment fails to operate with lower actual voltages or burns out with higher actual voltage.

6.09 Rotating disc meters remain quite firmly the market leader in energy measurement. In fact it could appear as if newer electronic metering devices had not even secured a foothold. But at the upper end of the market where metering covers bulk supplies to electricity distributors or very large industries, electronics are beginning to displace electro-mechanical devices.

6.10 The remarkable accuracy of rotating disc meters seems to have been secured at little cost per meter. However, it could well be that substantial incremental expenditures have been and will be incurred to reach high levels of accuracy, e.g. better than 2% at a fractional load, that may not be compensated by appropriate benefits. Meter engineers stress accuracy and often imply that a more costly meter with only a 1% error is "better" than one with a 3% error; and metering arrangements which reduce costs, but at a risk of some inaccuracy, tend to be condemned. This stress on accuracy as an end in itself can be said to be a luxury in a developing country. However, associated with the fine workmanship and careful design needed to reach greater accuracy are the valuable attributes of longevity and long-term stability. Another useful attribute of accurate metering, or perhaps of the pursuit of accuracy, is that disputes with consumers are reduced.

6.11 The versatility of such hardware as meters and timeswitches is much greater than might be judged from a catalog of items. This is because there are several ways in which the items can be connected into circuits. Also tariffs can be formulated which use the component information displayed on the one, two or three registers of a meter, and other information, in some more sophisticated way than the application of a price to each component. It follows, therefore, that the various items of hardware can be exploited to give an almost indefinite number of different tariffs. Of course, many of them would be assessed as having little economic merit.

Energy Meters

6.12 First, a technicality. The wires from the supplier to the consumer must number at least two. These wires are concerned with the supply of electricity; there may be others concerned with safety or communications. A 2-wire system requires a single-element meter, whereas each extra wire requires in principle another element to be added to the meter. By element is meant the assembly of coils of wire and magnetic paths which drives the meter forward as energy is consumed via that particular pair of wires. In fact each element could be a separate (single-element) 2-wire meter, but more usually the elements are assembled so as to drive a single shaft. This gives rise, for example, to a 3-wire, 2-element meter.

6.13 Quite generally the price of the meter climbs with the number of elements as it does with the number of registers displaying the output.

However, under some circumstances, especially a relaxed attitude to the need for accuracy, fewer elements can be used than is given by the "one less than the number of wires" rule. Such relaxations might be of particular application in developing countries. 1/

6.14 A fundamental characteristic of a meter is, therefore, the number of elements. Each element has a voltage coil and a current coil; the interaction of these two indicates energy. For the majority of meters, the voltage and current coils are simply inserted between the supply and the consumer without any transformations. However, for currents in excess of 100 A or for voltages in excess of 500 V, transformers are used to reduce the quantities handled by the meter, usually to 5 A and 110 V, respectively. The "meter" is then, of course, an assembly of the meter itself, some current transformers and a voltage transformer, and its accuracy has to be determined overall.

6.15 With the aid of current and voltage transformers and a several-element meter any practical alternating current supply system can be metered. Direct current systems present greater difficulty but fortunately are nowadays rarely encountered. For the WAPDA system, the meters used are single-element for single-phase (residential) supplies, two-element for three-phase, three-wire supplies often at high voltage to industry, and three-element for three-phase, four-wire supplies at 240/415 V to industry and the larger commercial premises.

6.16 Another classification of meters, important in Britain but of less interest elsewhere, is between the credit meter and the prepayment (slot) meter. The credit meter needs no explanation, though it should be realized that the meter has to be backed up by a system of assessing creditworthiness, collecting and refunding deposits, and using legal procedures to collect outstanding debts. With the prepayment meter, this set of responsibilities falls more or less on the meter mechanism -- it is therefore particularly suited to the residences of unsettled, mobile groups who have difficulty establishing credit.

6.17 While traditionally the prepayment meter is disliked by supply authorities, even though an annual surcharge of about one pound sterling is made in Britain, the device is found useful both to avoid getting the improvident into debt and to collect "bad debts" arising from credit meters. Theft from prepayment meters is a serious problem. An allied (and cheaper) device is the fixed-charge collector which disconnects the supply unless fed with coins at a certain time rate independent of the energy consumed.

1/ Crudely (but effectively with motor loads) three of the four wires of the usual low-voltage power system (3-phase, 4-wire) can be assumed to carry equal energies, the so-called balanced load, thus permitting a single-element meter to replace a 3-element one. More subtly a 2-element meter may be employed which does not assume a balanced load but which assumes -- more safely -- that the alternating supply voltages peak as they should at equal intervals in time.

6.18 For normal credit meters the drive spindle from the meter element(s) turns the register of, say, five dials, i.e. zero to 99,999. These dials have a tens-transmission mechanism and are either of the pointer type or the cyclometer (roller) type. Roller dials, following some early technical difficulties, are growing in popularity and can now be obtained with large digits to facilitate meter reading.

6.19 Instead of the single register, a meter may be fitted with a double or triple register to apply two or three prices. Figure 6.1 shows a double-register meter with large-figure roller dials. Effectively there are five digits since the 1/10th position is normally ignored. The change-over mechanism, which disengages the drive from one register and simultaneously engages with the other, also controls the "rate now operating" pointer on the right. This mechanism requires to be energized when one or the other rates 1/ is in operation, usually but not invariably by means of a time switch.

6.20 Figure 6.2 shows a triple-register meter with pointer dials. From the viewpoint of passing cost signals to the consumer, the rate-pointers at the top right are often not immediately understood. Also the fifteen (or eighteen) pointer dials running clockwise and anti-clockwise alternately look forbidding. Proposals have been made to signal the "rate now operating" more effectively to the consumer by using miniature traffic lights, remotely operated by the same timeswitch that controls the rate change. However the cost of the wiring and of maintaining the lights and the fear of disputes when a light fails and high-price energy is consumed without warning are deterrents to the realization. However, see paragraph 6.33 below, signals in the form of a separate switched electricity supply are being provided with the British day/night residential rate (named the white-meter rate).

6.21 By extending the design, 4-rate or even 5-rate meters could be manufactured. The task of reading such meters and billing consumers begins to look formidable if applied to more than a few consumers. A more practical approach, granted the engineering skills, is to design a self-calculating meter to give the price-weighted energy consumed. A (single-register) meter would be fitted with impulse contacts. Such contacts would transmit a signal to a second register whenever, say, a kWh had been consumed. Normally a fixed impulse rate would be used of, say, 1 impulse per kWh. But fairly easily, the impulse rate could be varied with the relative price in operation. The end result would be the price-weighted energy consumed displayed on the second (electrically driven) register, supported by the unweighted energy displayed on the normal (mechanically driven) meter register. Of course, such complexity of metering is not likely to have an application with residential consumers, though with large industries

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1/ The choice is often made to energize the mechanism when the low rate is to operate; that is failure tends to be to the high rate. This avoids the situation where the consumer is content to be permanently on the low rate owing to a bad connection.

this kind of metering is not much more complex, if at all, than the present assembly of energy meter, maximum demand indicator, resetting timeswitch and power factor penalty meter. Figure 6.3 illustrates this point: all the equipment shown is tariff metering, though the small subsidiary panel (top right) is for load research purposes.

6.22 At the other end of the range of metering complexity, a no-meter solution can be adopted particularly for the smallest residential consumer. Some other basis then has to be used for the electricity billing. These no-meter methods are discussed in Annex 9. The assumptions are that the investment in metering above that required for the alternative is unjustified by any improvement in resource allocation, and that the technical possibilities of wasting electricity owing to the zero-marginal-cost message are small. These assumptions clearly hold in the frequent case of time-switched, no-meter street lighting where the lamp wattage and timeswitch schedule are publicly evident.

Timeswitches

6.23 To achieve temporal variations in prices by time of day or day of week a timeswitch is necessary -- there are alternatives giving much the same result but for the moment these will be ignored. Temporal price variations by month or season of year can be made via the meter reading cycle, granted regular and sufficiently frequent readings. But even here a timeswitch, perhaps better called a "date switch", can be used to ensure the prices vary on the declared dates.

6.24 The timeswitch, usually boxed separately from the meter, signals the two or three register meter that it is time to vary the rate. This requires only a very small current so that the timeswitch is said to be a light-duty one (usually up to 2 A). In contrast a heavy-duty timeswitch is capable of making and breaking the consumer's supply of up to 100 A.

6.25 A timeswitch consists of four sub-assemblies: the constant-speed motor or clock mechanism; the engraved time dial(s) carrying pins to strike the switches; the quick-acting switches tripped "on" or "off" by the pins; and the case and terminal block. Of these four, the most characteristic of a design is the type of constant speed motor and this choice has the greatest influence on price for a given quality of construction.

6.26 Even a small error in timekeeping soon accumulates to a large error if maintained. For example, a steady loss or gain of only 1 minute a day, i.e. 1 part in 1,440, accumulates to 30 minutes in a month and to 6 hours in a year. Most tariff applications require timekeeping to be

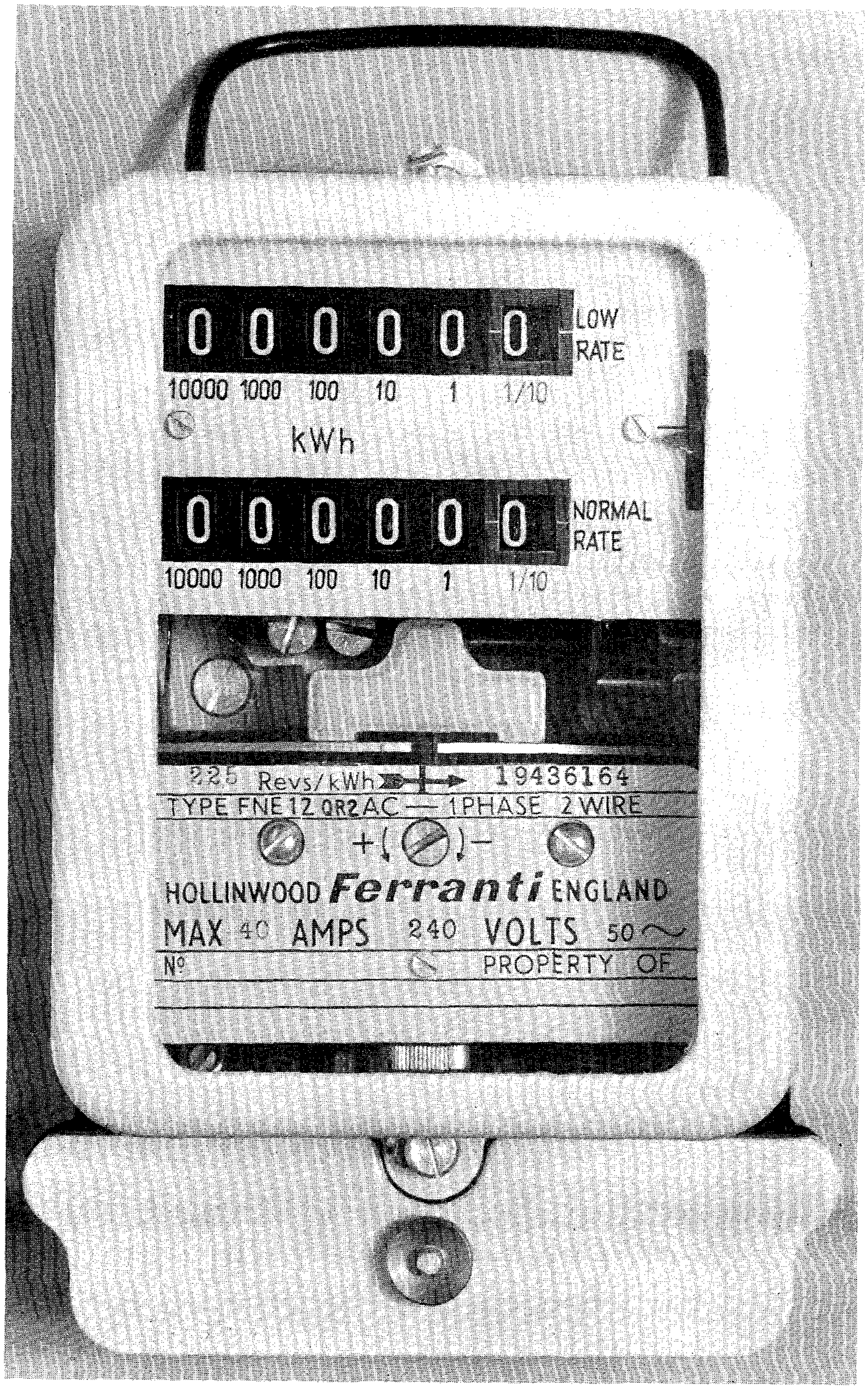

Figure 6.1 - A double-register meter with large-figure roller dials.

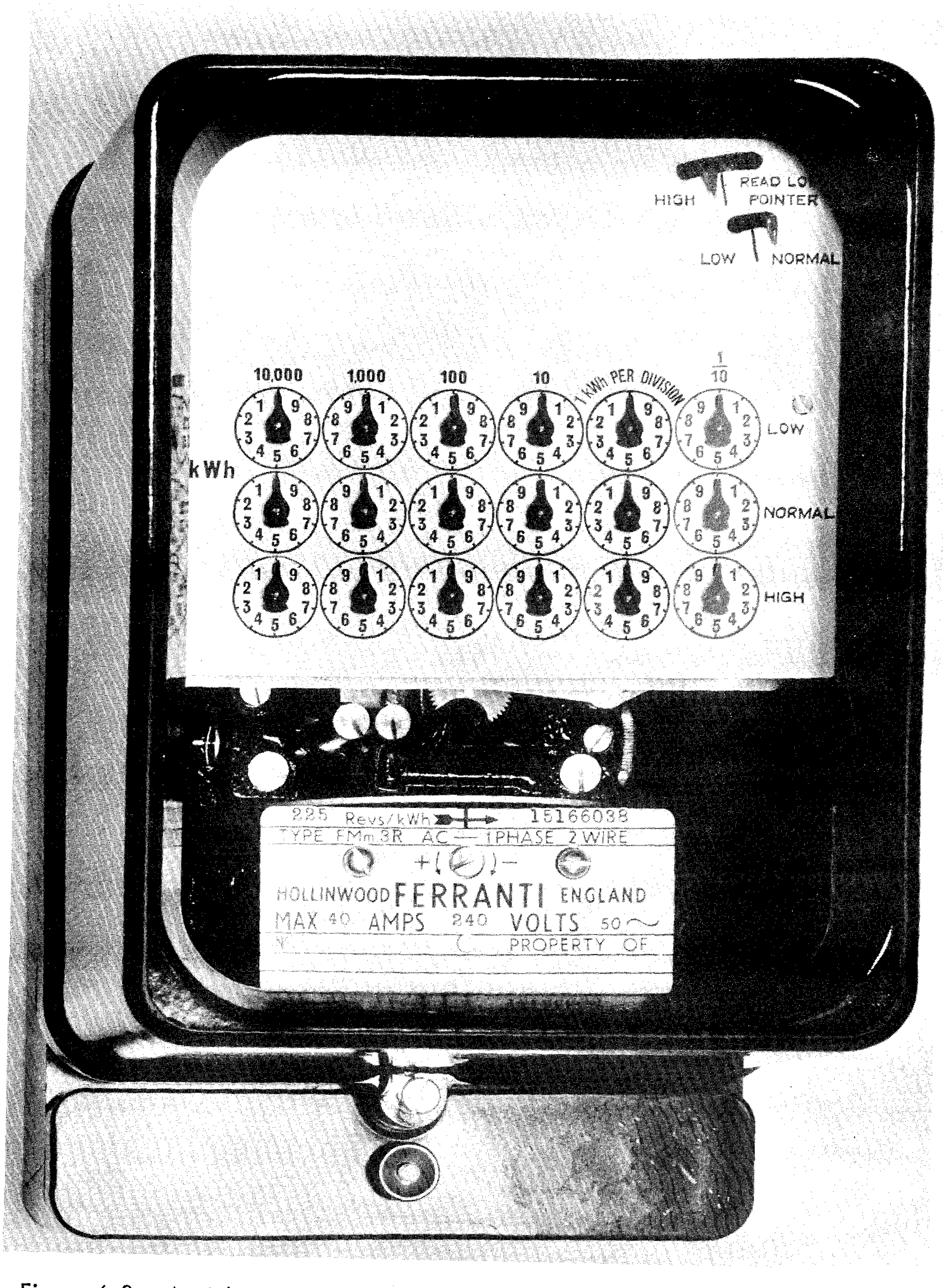

Figure 6.2 – A triple-register meter with pointer dials.

Figure 6.3 - Metering installation for a large industry with several incoming supplies.

within, say, 10 minutes. A good-quality escapement can keep time to within 5 minutes a month so that it would need manual correction every few months. 1/

6.27 Escapement timeswitches with the usual clock mainspring which do not demand a controlled frequency of the power supply can be hand-wound, but more usually will be wound by the power supply. The spring in one example of such a mains-wound escapement (11-jewel lever, fully compensated for temperature variation) keeps the clock running for only 9 hours without power supply. However, up to 144 hours spring reserve is readily attainable. The escapement requires cleaning and oiling, say, every two years, whereas other kinds of timeswitches (which place little or no reliance upon escapements) should be overhauled every seven to ten years.

6.28 The simplest and cheapest form of constant speed motor is the synchronous motor. For accurate timekeeping, the supply has to be controlled cumulatively in frequency and be unfailing. Failures of significant duration, if very infrequent, can be dealt with by visiting consumers to reset timeswitches after each failure. Generally, however, it is accepted that synchronous timeswitches are unsuitable for tariff purposes. 2/

6.29 Granted a controlled frequency, the most satisfactory timeswitches for tariff purposes combine the virtues of the two different kinds of timekeeping described in the two previous paragraphs. The result is called a synchronous spring-reserve timeswitch 3/ and can be had with up to 30 hours reserve. When the power supply is on the synchronous motor drives the time dial but whenever power fails the escapement, driven by a reserve mainspring, takes over. The escapement therefore has only a light duty and its timekeeping errors have little

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1/ After reading Chapter 3 "Obstacles to Revenue Assessment and Collection" the reader might feel apprehensive about giving this additional duty to the meter reader but, of course, every step necessary towards the eventual bill can be made falsely. Perhaps some false steps are more inviting than others.

2/ Two exceptions can be noted. One is the resetting of maximum demand integrating periods, that is every quarter or half hour, if a clock-time regime is not thought imperative. WAPDA uses synchronous timeswitches for this purpose. Another is the date switch, see Figure 6.4, where the dial makes a revolution once a year and the design assumes that, in aggregate, power failures are only a small proportion of a year.

3/ This definition includes rocking-escapement or forced oscillation models which achieve the same end by different means.

impact on the overall timekeeping. The overall timekeeping has, more or less, zero cumulative error depending of course on the continuity of supply. Annex 10 proposes an experiment with controlling the frequency of the WAPDA system in such a way as to make this kind of timeswitch keep satisfactory time. If the frequency cannot be controlled, then the next best type of timeswitch for temporal pricing on the WAPDA system would be that using a mains-wound escapement.

Services Provided by Timeswitch

6.30 The essential service for tariff purposes is of course to vary the rate applied by a two(or three) register meter. For a day/night or time-of-day tariff the timeswitch dial revolves once every 24 hours. The high rate can be applied more than once each day to cope with, say, an early morning peak and an evening peak. The minimum dwell on any rate cannot for mechanical reasons be less than 30 minutes. Day-of-week omitting devices are readily available so that the low rate can, if desired, be applied to the whole of Sunday.

6.31 Figure 6.5 illustrates a variety of temporal tariffs that might be applied to a winter peaking system. Reference 1 (a) is a simple day/night rate, whereas 1 (b) employs a day-omission device to give Sunday relief from the high price. Reference 2 (a) is for a double-peaking system with a midday valley as well as the night-time one. Reference 2 (b) gives Sunday relief. Reference 3 (a) again shows a simple day/night rate but 3 (b) gives relief in summer. The result is a rudimentary seasonal time-of-day tariff. Reference 4 (a) applies the high prices to a narrow time band as might be employed for a system dominated by the lighting load and 4 (b) implies the possibility of Sunday or summer relief.

6.32 Reference 5 of Figure 6.5 shows a sophisticated seasonal time-of-day rate requiring the 3-register meter of Figure 6.2 and the elaborate timeswitch of Figure 6.6. This has a weekly dial running through 7 days by 24 hours and a 52 week dial. Since the high price is applied for relatively short intervals with a medium price available to dampen intermediate demands in neighboring time periods, the high price conveys a firmer cost message and hence this rate may be more effective than rates of simpler design. However, the necessary timeswitch presents engineering problems in its design and manufacture.

6.33 Where a timeswitch controls the price to a consumer, he needs to know that rate is operating and what rates are coming in the future. The "flags" on the meter indicating the rate currently in effect were earlier described. Clearer signals of this rate are felt desirable than that provided either by the flags or by the consumer remembering the time.

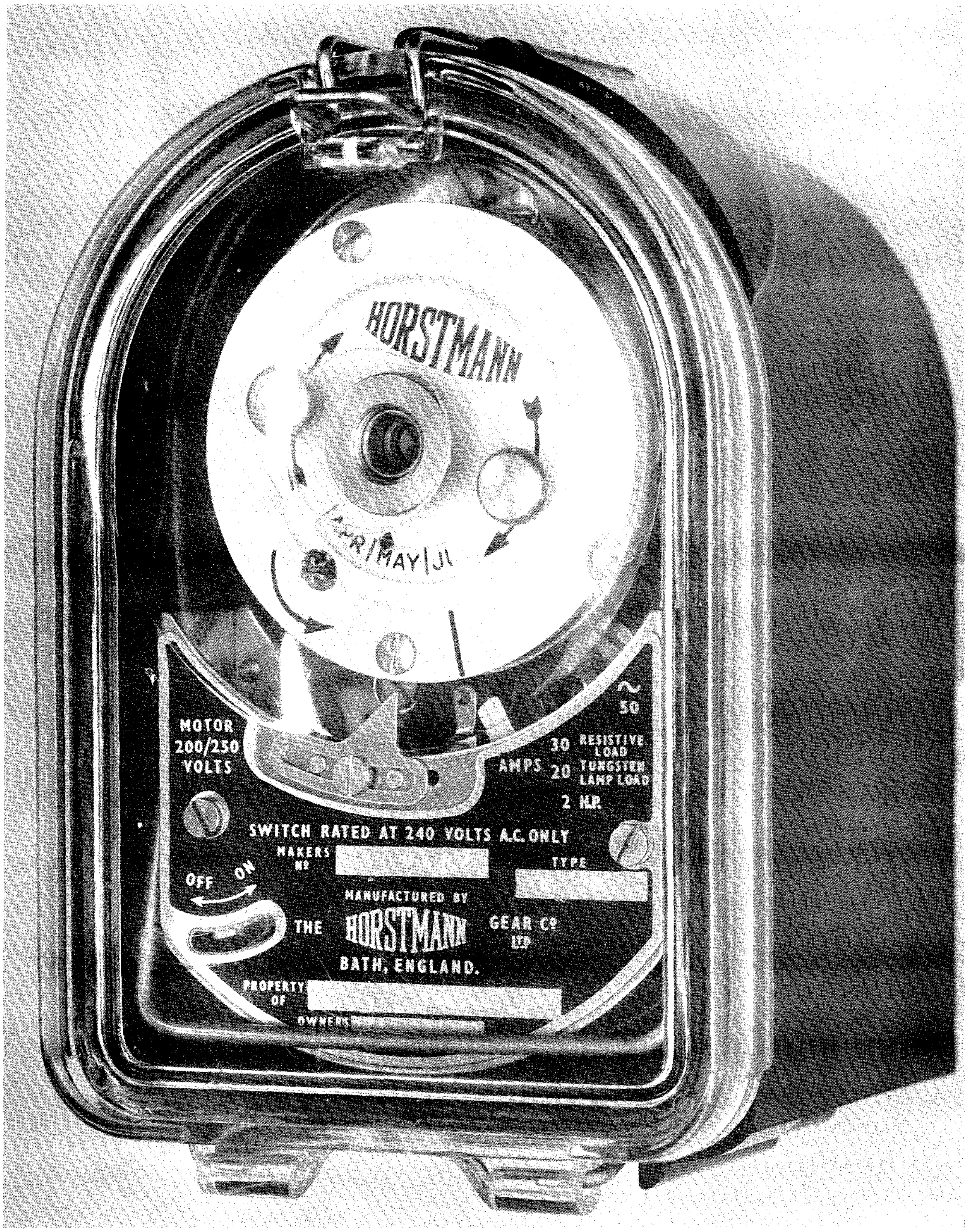
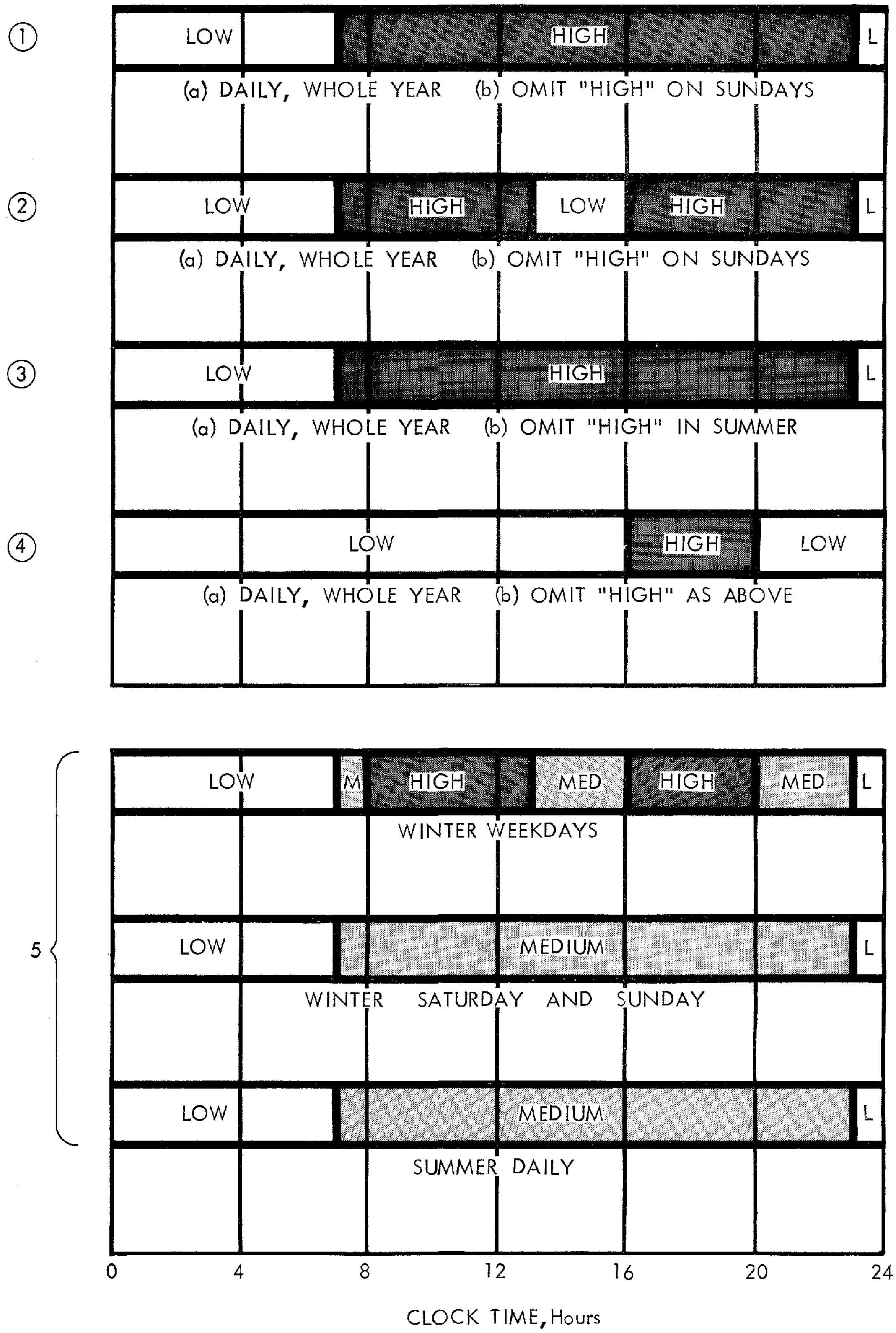


Figure 6.4 - A date switch to control a seasonal tariff which uses a synchronous motor without spring reserve.

EXAMPLES OF TEMPORAL PRICING
(POWER SYSTEM WITH WINTER PEAK)



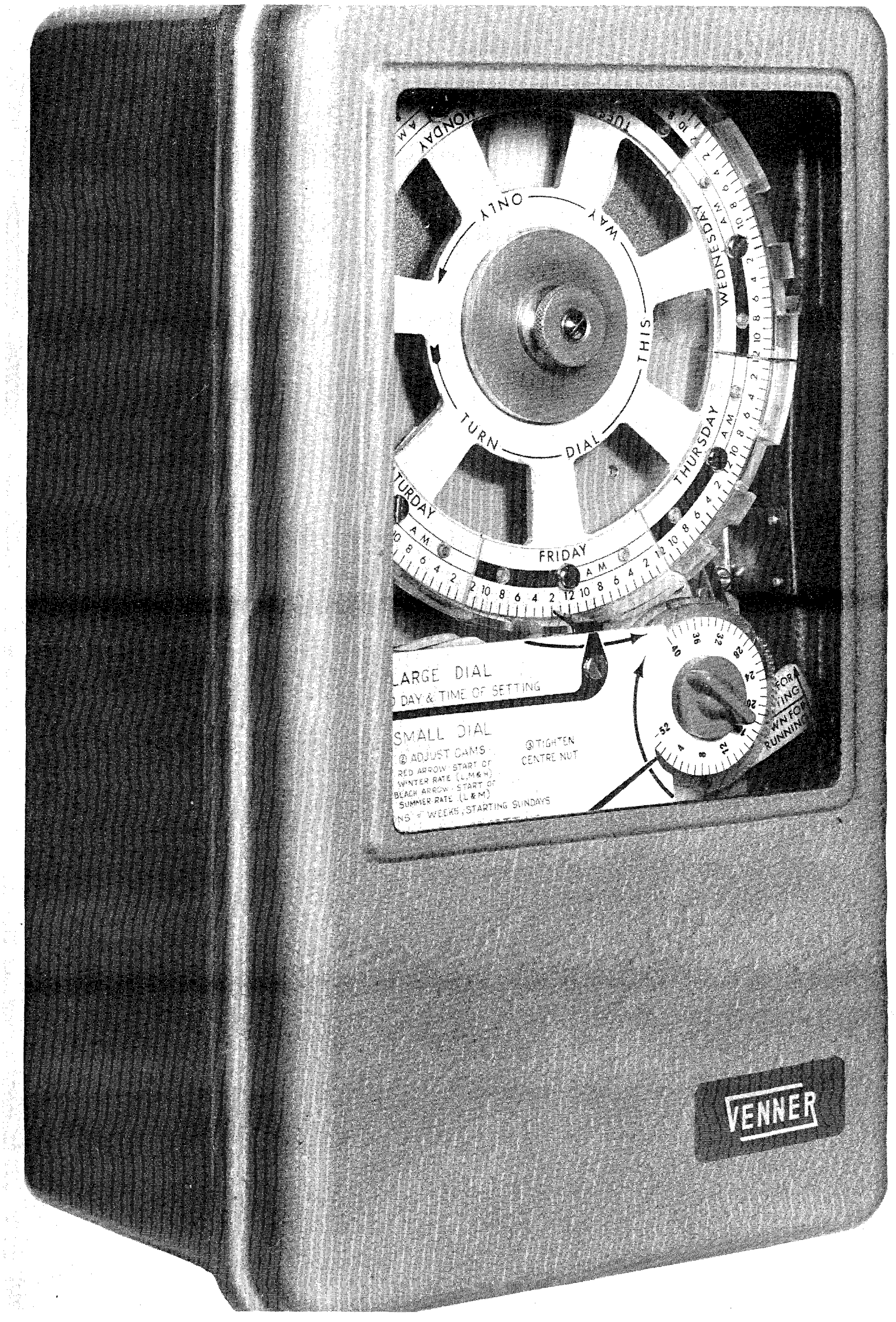


Figure 6.6 - An elaborate timeswitch designed to switch a triple-register meter for a seasonal

One answer is for the consumer to have his own timeswitches synchronized with the supplier's switch and controlling non-essential usages. Another, adopted in Britain for the domestic day/night rate, is to fit a heavy-duty pair of contacts 1/ to the supplier's timeswitch to control the consumer's loads as the latter sees fit. In practice the consumer will connect storage water heating and storage room heating to the controlled circuit so that he automatically takes advantage of the cheap night rate.

6.34 Closely allied to the day/night rate is the restricted-hour domestic rate used for storage heating in Europe. Other uses for electricity are supplied at the normal rate and with 24-hour availability. The restricted supply or circuit is fed through a separate single-register meter and charged at a low rate. This supply is disconnected by the tariff timeswitch except during off-peak periods. Obviously this arrangement provides a very clear signal as to when the cheap rate applies: at other times this circuit is disconnected. But the consumer has to be discouraged from duplicating the storage appliances on the restricted circuit with others on the normal 24-hour supply.

Demand Metering

6.35 Temporal modulation of demand pricing is certainly possible and examples of seasonal/maximum demand tariffs are given in Chapter 2 where two-part tariffs are discussed in general. The normal task of a maximum demand tariff, however, is to apply pressure to the consumer's use of electricity when it is running at an above normal rate so that he smooths his demand.

6.36 The normal maximum demand indicator is an attachment to a standard energy meter. A moving pointer is driven over a scale as energy is consumed but is reset to zero at the end of each integrating period. The resetting signal is either given by an internal synchronous clock or by an external synchronous spring-reserve timeswitch. 2/ The moving pointer drives a slave pointer upwards only so that the latter indicates the maximum demand reached since the meter reader last called and set the slave pointer back to zero. These readings are held close to the end of each month because the time between readings can affect the indicated demand.

1/ The consumer cannot share the circuit to the rate-changeover mechanism since then he could manipulate the mechanism.

2/ Precision pendulum clocks are sometimes used for important industrial supplies. Usually the integrating period is a half or quarter hour.

6.37 The meter for important supplies is often read by an engineer and the consumer provides a witness. This approach is necessary because the demand reading is lost forever once the slave pointer has been set back to zero. Two solutions have been proposed to overcome this meter reading difficulty with maximum-demand tariffs. For smaller consumers, the maximum demand is to be displayed on the usual slave pointer which when reset to zero, even without a witness, throws the reading into a roller-figure cumulative register. In this way, it is proposed, maximum demand tariffs could be applied on a wider scale with less risk of fraud.

6.38 The other solution could only apply to the largest consumers since the hardware is very expensive. A complete record is to be kept of the half-hourly demands either on a printed tape (the printometer or "Maxiprint") or on a punched paper tape or magnetic tape. The last is an innovation by two American manufacturers and so far has had very little practical application.

6.39 An energy meter can also be fitted with two maximum demand indicators and they can be arranged to operate alternately in winter and summer to form a seasonal maximum demand tariff without relying on the date of the meter reading. In like manner a double maximum-demand meter could be used for a day/night tariff.

6.40 For the smaller industrial consumer of less than, say, 50 kW maximum demand, the need is felt for lower-cost metering than that provided by the standard device. These alternatives are less satisfactory from an engineering viewpoint. A thermal demand indicator is often used in which the heating effect of the current taken by the consumer is stored in a thermal mass but the heat is drained away by natural cooling. A maximum-reading thermometer gives some indication of the consumer's maximum demand but, as may be gathered, the precise definition of the measured quantity is uncertain.

6.41 Other low-cost capacity assessment devices are available. These can be briefly listed as:

Main supply fuses
Supply-circuit fuses
Thermal load limiter
Electromagnetic load limiter

Some of these are described in Annex 9.

6.42 Another low-cost demand pricing device is the load-rate meter used for domestic supplies in Norway. While it is a complex device it is well-engineered, and the large market in Norway for the meter prevents the complexity from greatly affecting the price. The meter, see Figure 6.7, has three price scales. The "normal" register is charged at a normal

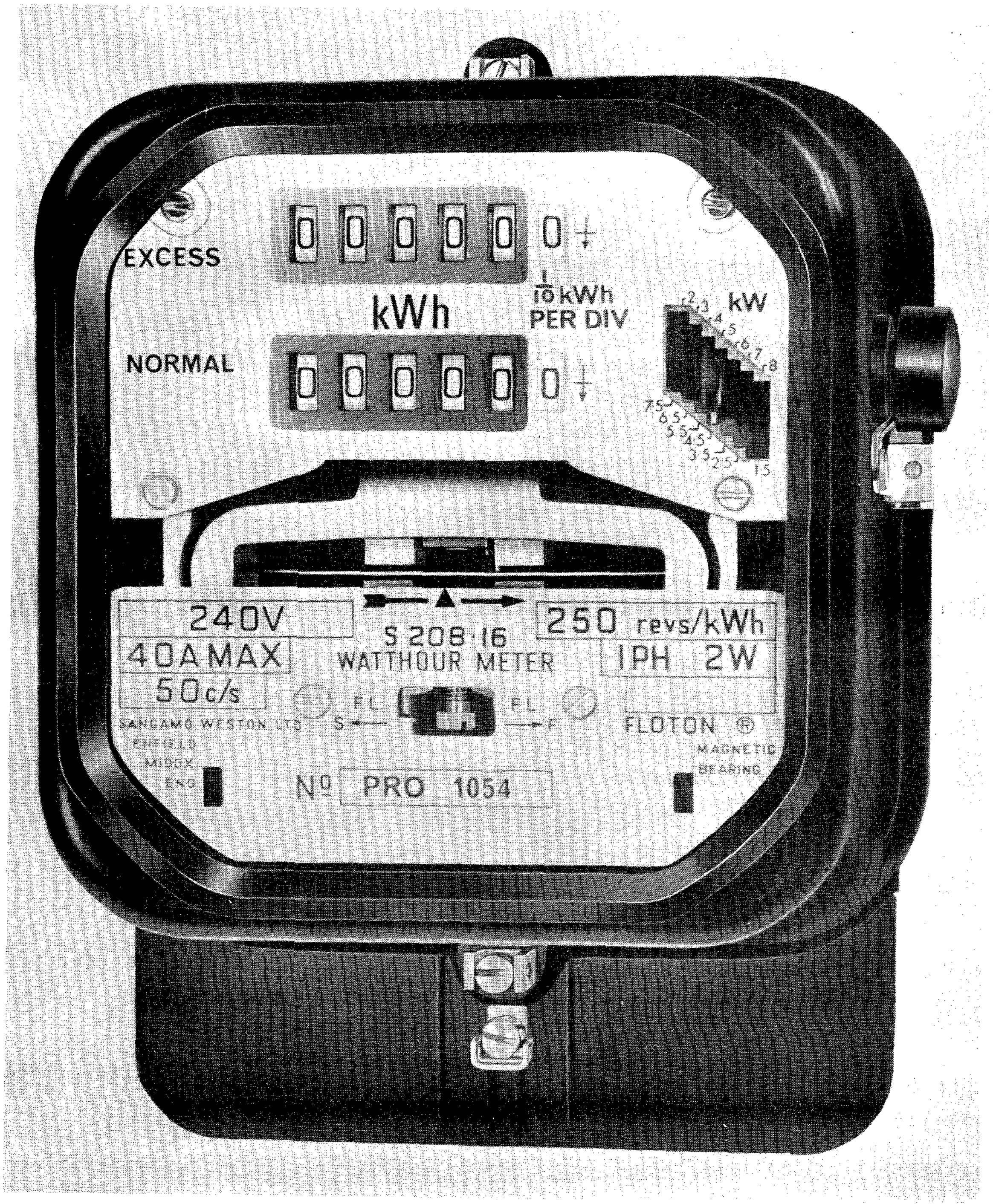


Figure 6.7 - The load-rate meter is extensively used in Norway.

price, whereas the "excess" register carries a surcharge. The demand scale bears an annual rental of the order of US$10 per kW of "subscribed demand". Whenever, even momentarily, the consumer's demand exceeds the subscribed demand, the excess register is driven to record the excess consumption in kWh.

6.43 The impact of these prices is to make a consumer avoid unplanned excess consumption by renting sufficient subscribed demand for nearly all his needs. Equally the consumer is encouraged to have a level load curve 1/ as with a maximum-demand rate. Indeed it might be argued that this kind of meter can give an incentive to smooth demand that is more effective than that provided by a maximum-demand meter. With the latter, once a high demand has been set up in a month, the only incentive is to avoid a still higher demand.

Remote Meter Reading

6.44 So far the hardware has been regarded as a meter perhaps associated with a timeswitch where the output is displayed on registers to be read by a meter reader. Methods have been proposed involving various items of ancillary hardware to assist the meter reader with his task. These can be called "slick meter reading" methods and have little interest from the viewpoint of differential pricing.

6.45 A more radical proposal than merely to assist the meter reader with his task is to eliminate the visit to the consumer's premises. The consumer's meter then has to be fitted with impulsing contacts or with a register read-out device. Impulsing contacts have to be continuously interrogated whereas read-out devices only require interrogation whenever an electricity account is being prepared. By interrogation is meant the act of opening a communications channel between the meter and a remote central point where the billing data are collected, usually envisaged as equipped with a computer.

6.46 Such installations do not as yet exist in the sense that a large number of meters are read in this way on a commercial basis. Instead there are several experimental installations. The lack of commercial exploitation of these inventions arises because they fail to compete economically with existing practices even in the most developed countries where labor costs of meter reading relative to the cost of hardware should be greatest.

6.47 Various communications channels can be used. Special "pilot" wires can be installed. The public telephone system can be used, even without interrupting the use of the telephone. Spare channels are often available on wired television networks where the programs are brought to

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1/ The excess-consumption register can be disengaged by the action of an external timeswitch at, say, night time to give preference to night usage.

the homes over a special network. Naturally, the power supply network itself is favored as a communications channel by the supply authorities but, technically, sending signals from the consumer to a central point -- rather than the other way round -- presents formidable difficulties. Nonetheless the remote reading of consumers' meters over the supply network has been demonstrated with the readings collected at a central point.

6.48 Looking into the future these developments are of great interest to the tariff maker in that they would facilitate temporal pricing. The consumer's meter would merely record the total energy consumed but would be interrogated at every price change and the readings recorded centrally and priced. Obviously this would permit complete flexibility of pricing. However, unless a price schedule by time of day and so on had been agreed beforehand, audible and visual signaling devices would be required to let the consumer know the price he is paying. 1/

6.49 These developments seem of little immediate interest to supply authorities in developing countries. However, since they present engineers with fascinating problems, they tend to attract inventive ability and considerable attention in the literature on metering innovations.

Telecontrol and Rates for Interruptible Supplies

6.50 In Chapter 7, hardware, known as telecontrol, for the remote operation of switches in consumers' premises will be described. The supply mains provide the path for the control signal. Telecontrol can be used to operate the changeover mechanisms of two or three-register meters and seems particularly appropriate to replace more complex timeswitches. The relative economics of timeswitches and telecontrol are, however, critically dependent on the density of application within the area of the signal-transmitting (injection) equipment with low density, or slow rate of rise of density, favoring timeswitches. Again this is described in Chapter 7.

6.51 Tariffs can be based upon the telecontrol facility. The tariff most frequently applied is a preferential rate for domestic water heating where the supply to a storage water heater can be interrupted at will by the supply authority. Preferential rate contracts can be negotiated with very large industrial consumers, which permit the authority to restrict their supplies to some agreed level on so-many occasions for up to so-many hours. With such consumers there is little point in using telecontrol, and a telephone message, confirmed in writing by teleprinter, provides a more effective link.

1/ As Chapter 2 emphasized, pricing for efficiency would also require knowledge of future prices.

Application

6.52 The above descriptive catalog of hardware for electricity pricing, with the emphasis on differential pricing, is fairly complete insofar as the devices are now in manufacture, or have been recently, and their application has found favor somewhere. An historic view would bring to light other devices. Equally, as with temporal pricing using remote meter reading, a future view would embrace developments which are not yet commercially exploited. All the emphasis has been on the energy consumed, that is, the working component of the electricity current, but Annex 11 has been added to broaden the discussion to include the magnetizing component.

6.53 The catalog is nowhere near complete if the various items of hardware are regarded as building bricks. The mechanisms can also be modified slightly from an engineering viewpoint, but the impact of such minor modifications on the practical application may be very great.

6.54 Apart from whether hardware is available in terms of practical designs, the most pertinent question to ask is how expensive is the metering required for the desired pricing. Then some view can be formed as to whether the application is worthwhile. Annex 12 tabulates the prices of some of the hardware that has been cataloged but these prices are no more than rough guides. As already explained, apparently minor modifications required to make the equipment suitable for use on a given system or in a given environment may greatly affect the price. The price is also dependent upon the quality of the engineering. For example, if a large industrialist rather than a residential consumer is to be metered, high-quality precision metering may well be justified.

6.55 As well as increases in the quality of meter engineering, decreases can be envisaged. For example, the present practice with private tubewells is to install a 3-phase, 4-wire single register meter listed as Ł15 (US$36) in Annex 12. If, however, single-phase (assumed balanced load) metering were accepted, then day/night or time-of-day rates could be applied with a metering purchase price of Ł22 (US$53) for a double-register, single-phase meter plus an escapement mains-wound timeswitch.

6.56 As another example of quality reduction, suppose that it is desired to apply temporal pricing to private tubewells in West Pakistan with the <u>minimum investment in metering</u>. The proposal then might be:

a. to install a single-phase, single-register meter, i.e. the cheapest kind, and

b. to disconnect the voltage coil of this meter by means of a timeswitch at times of ample supply so that supply is then free. 1/

The farmer thus faces a two-price tariff of which one price is zero. Revenue would also be collected, as partly at present, by a monthly levy on the size of tubewell motor, or by some other unmetered basis. The incentives to tamper with the metering would seem to be less than at present, and the purchase price of the metering would increase from Ł15 (US$36) to only Ł17.45 (US$42). Obviously the trade-off is quality of measurement for significance of cost message.

1/ The meter has to be adjusted so as not to creep forwards or backwards when current is flowing through the current coil but the voltage coil is disconnected.

7. PHYSICAL LOAD CONTROL

7.01 As was emphasized in Chapter 2, one of the principal functions of electricity prices is to ration the use of electricity and hence the resources going into electricity production. To emphasize this point boldly: prices are charged for kWh in order to discourage their consumption. Indeed it might be possible to operate an electric power system that offers electricity to all users free of cost, much as highway or police services are offered by government. That is, each consumer's electricity or tax bill, as the case may be, would depend on factors other than amounts of energy consumed. Such an electric system clearly would divert a larger quantity of capital, fuel and other resources into the electric power sector -- the more so if the electricity or tax bills were to be independent of electricity consuming capacity. 1/ Economists would agree, however, that a country with "free" electricity would be a "poorer" country. Resources would almost surely be diverted to many electricity uses that are quite unimportant and wasteful -- resources that could be better used elsewhere.

7.02 A price mechanism, however, clearly is not the only method by which electricity consumption can be rationed. As the discussion below emphasizes, there are many practical ways that may be used as substitutes for a price mechanism to perform this function. This chapter discusses the various physical rationing techniques and devices.

7.03 A major argument against all physical rationing devices is that they generally require someone other than the users to determine priorities for the use of electricity. This in itself may not be a persuasive argument for someone who has a strong predisposition to believe that efficiency comes with centralization of decision making. Yet physical rationing of electricity is essentially an all-or-nothing proposition for a group of consumers, for a specific consumer, or for a particular use of electricity by a consumer group. The more fine is its discrimination, the more expensive is a physical rationing scheme likely to be. On the other hand, the more fine is the discrimination, the less objectionable can be the consequences of the all-or-nothing decision. All this should become clearer from the discussion to follow.

7.04 The fundamental objection to the consequences of all-or-nothing decisions to furnish electricity supply or not to furnish it over some interval of time is that not all of the electricity delivered to a consumer at any instant of time is of equal value to him; moreover, electricity at one instant of time is not a perfect substitute for electricity at other instants of time.

1/ Some rationing of highways is realized by taxing the use of motor vehicles, gasoline, tires, drivers, etc.

7.05 The fact that the first increments of electricity delivered to a consumer at any moment of time are of more value to him than the last is quite generally accepted. The economist refers to it as the principle of diminishing marginal utility. It is the basis of what practitioners call value-of-service pricing. It explains why a consumer almost always obtains more value for the electricity provided at a fixed price during, say, an hour, than he voluntarily pays for it; it explains why he would generally be willing to pay extra not to have his service interrupted. This excess in value over what the consumer pays for electricity consumed was already emphasized by the French highway engineer, Dupuit, in the 1840's before economists elaborated this concept of "consumer's surplus".

7.06 Evidently the amount of consumer's surplus destroyed by a decision to interrupt service over an interval of time can be reduced with increases in the selectivity of the application of the interruption. By cutting off the storage water-heating element only of all consumers in a system, relatively little consumer surplus may be destroyed if the time period is sufficiently short, although many consumers may be much inconvenienced <u>occasionally</u> as a result of this device. The reason why little consumer's surplus is destroyed by chopping off the storage water-heating load is that electricity consumed in one hour for this purpose is a close substitute for electricity consumed the next hour. Cutting off the supply of a particular consumer in all uses evidently cuts off not only his low priority stored-energy applications, but even the high priority lighting or motive power applications. In the extreme the cutting-off, as a matter of policy, of the highest priority uses of a particular consumer will encourage him to buy costly stand-by generation just for these uses, or to substitute more expensive or inferior technology that does not critically depend on a steady uninterrupted power supply. Finally, if physical rationing involves cutting off all of the supply of a group of diverse customers who happen to be connected to a common feeder, the chances are that even the careful and thoughtful planner will destroy thereby even more consumer's surplus.

7.07 In contrast to an all-or-nothing method of physical rationing, a method may be used which in fact assigns quotas to individual consumers or groups of consumers. That is, a device cutting off a consumer completely comes into play only if the consumer exceeds some predetermined magnitude of load or energy. Such rationing methods do have the advantage of allowing each consumer to allocate the amounts available to him to the uses he considers most important. A simple example of such a rationing device is the load limiter. If used as a substitute for a meter, it has the disadvantage of providing energy at zero marginal cost which was held to be ill-advised in Chapter 2. If, in contrast, the device were to put a ceiling on the amount of energy used over a period of time, it could cause hardship to a consumer who has used up his energy quota but who has a long time to wait for his next quota. The fundamental argument against quotas as substitutes for meters is that they do not allow for individual differences. Thus they tend to cause inefficiency. The relative value of the incremental use of electricity may be very different to different consumers. Yet the rationing system does not allow for these differences. Of course, physical devices can also be used in connection with tariffs. In such cases, they provide examples of two-part tariffs as discussed in Chapter 2 and they should be evaluated as such.

7.08 Using an ideal price system as a substitute for physical rationing maximizes the consumer's surplus accruing to the economy. 1/

7.09 Physical rationing schemes which involve the selection of specific customers without any compensation may encourage a "black market" for electricity during periods of short supply. Because the value to the consumer of the electricity not to be supplied to him exceeds the cost to him of this electricity, a consumer can be expected to offer money not to be cut off. These revenues are not likely to accrue to the electricity supply authority. Such side payments, moreover, will probably not have much of a rationing impact because they are likely to be structured so as to leave incremental costs unchanged. If such a system of extra payments accompanies a physical rationing system, the politically weak, the less influential people, and the poorer consumers may be cut off rather than the incremental uses of a wider class of consumers. It is the former who might most unfairly be called on to bear the brunt of the shortages.

7.10 Discussion on the physical rationing of electricity is sparse. 2/ Equally it is rarely practiced using hardware other than that already provided to deal with emergency overloads. An electricity authority often seems to see its prime duty as the provision of adequate capacity. It does not question the merit of the demand for electricity placed upon it.

1/ The theoretical economist will wish to point out that this proposition needs to be qualified for producer's surplus and also for weighting different consumers' surpluses to allow for inequities in income distribution.

2/ "Report of the Group of Experts on the Quality of Service - Generation and Transmission" by Stasi and Janin. UNIPEDE Congress, 1970. This report recognizes both the distributive and selective approaches to a supply deficit, as the following extract shows:
"It is necessary to prepare a strategy in order to share the inevitable load shedding as much as possible. This strategy should obviously be determined according to the nature of the consumer, the type of equipment involved, the duration of the deficit, etc. However, it should be noted that interruptions to supply, even those of short duration, sometimes have considerable consequences on certain mechanical operations when they involve electronic processes, even simplified ones. Furthermore, the density of housing, places of work or transport give rise to considerable troubles when incidents, even short ones, occur. In addition to the direct disturbances affecting a large number of persons, there are the indirect risks which are sometimes serious, such as the consequences of individual or collective panic.

"Supply interruptions in the security services (public health, police, priority telecommunications, signalling, etc.) would have dramatic consequences.

"The particularly vulnerable consumers are generally prepared for interrruptions of whatever kind they may be (generation, transmission or distribution) by having stand-by sets, accumulators or special emergency supplies."

Any shortage is seen as a temporary affair to be dealt with by acquiring capacity and not by eliminating demand. In fact, measures taken to suppress demand are likely to be taken by an electricity supply undertaking as a confession of failure rather than as a solution to a problem. There is, therefore, a thinness of discussion and experience relating to physical rationing. The account given here is not based on the same directed opinion and thoughtful experience as could be readily found concerning temporal electricity pricing. The introduction of such pricing policies in France and Britain provides a working basis for an adaptation to the special circumstances of a developing country. In contrast, the examples that could be quoted of physical rationing turn out on closer examination to be examples of price rationing where the hardware involved (telecontrol, load limiters) has only the overtones of physical limitation. 1/

7.11 Discussion on some matters closely allied to the physical rationing of electricity is, however, to be found, for example the following:

Risk of Failure
one paper 2/ describes the connection between the plant margin (spare capacity) and the risk of failure of supply, at full voltage and at reduced voltage, in terms of the expected proportion of winters in which supply fails in an indefinitely large number of winters.

System Collapse
Concatenation of plant malfunctions and human error can bring about a total collapse of the system. 3/ This differs from supply failure where, by the emergency or hand tripping of certain feeders, the bulk of consumers are kept supplied.

Costs of Interruptions in Electricity Supply
This document 4/ describes the application of a questionnaire to industrial, agricultural and commercial consumers in Sweden seeking the estimated costs of the impact of loss of supply of various durations: for example, 0-1h, 1-2h, 2-8h, 8-24h and 24-48h. Estimates were also prepared for doméstic consumers. The work is thoughtfully executed and fourteen references are given.

1/ A physical limit that can be lifted at a price is of course merely another tariff.

2/ "Economics of System Planning" by T. W. Berrie, Electrical Review 15/22/29 September 1967.

3/ "The Blackout: It All Happened in 12 Minutes", by L. M. Olmsted, Electrical World, 24th January, 1966.

4/ "Costs of Interruptions in Electricity Supply" (Report from Committee on Supply Interruption Costs), O.A. Translation 450, Electricity Council, London.

Quality of Supply

One paper 1/ gives the following list as the attributes of supply quality:

1. supply continuity
2. maintenance of frequency
3. wave purity
4. voltage regularity

    4.1 maintenance of voltage

        4.11 rapid and cyclical voltage drops (flicker)
        4.12 slow voltage variation
        4.13 short voltage drops (voltage dips caused by faults)

    4.2 equality of multiphase voltages

Quality therefore embraces continuity as well as other attributes such as a steadily maintained voltage.

7.12 The general direction of these papers is the search for some ground rules in the provision of "adequate" generation, transmission and distribution facilities taking into account the loss of social product or consumer's surplus consequent upon an imperfect electricity supply. So far the search is in its early stages, but there is already a recognition that the working solution "as perfect as we can" may not turn out to be the most economical solution.

Emergency vs. Routine Outages

7.13 In an emergency with the plant and lines overloaded and liable to be damaged, the usual engineering practices come into play. These range from the automatic tripping of circuit breakers without regard to the inconvenience caused to the public, to the selective interruption of supplies where circuits have been classifed as having or not having priority. Such emergency measures shade imperceptibly into routine measures when the aim is to distribute the inconvenience in a less arbitrary way than with emergency tripping. Equipment requiring investment can be proposed to aid the engineer in his task of limiting demand in a selective way having regard to the impact of the loss of electricity supply.

Global Demand Reduction

7.14 For the system as a whole as opposed to any circuit, the first restraining influence on demand is the voltage regulation (fall). This occurs naturally in times of heavy demand, particularly where, as in West Pakistan, the distribution system is strained and tap-changing transformers are not operated to raise the voltage. With an unstrained distribution system normally giving full voltage at times of heavy demand, tap-changing transformers could be operated to lower the voltage and hence reduce demand. Thus by supplying everyone with lower "quality" there is an increase in quantity.

1/ "Report of the Joint Group of Experts on the Quality of Supply Distribution" by P. Gaussens, UNIPEDE, September 13-17, 1970.

7.15 When interviewed, several manufacturers complained of the excessive voltage reductions of the WAPDA supply. In particular motors were liable to burn out when the voltage was low, and sometimes work was stopped for fear of such damage. 1/ Although the specific voltage drops reported by consumers may have been the result of weakness of the distribution system, the alternative to low voltage might well be disconnection.

7.16 Another restraint, affecting powered machines rather than lighting and resistive loads, is provided by falling system frequency. To a very limited extent frequency can be deliberately reduced but at, say, 48 Hz for a 50 Hz system there is a risk of a complete shut down should the synchronized generators fall out of step. Nonetheless, frequency reduction may be a useful load reduction method particularly for systems whose customers do not rely, e.g. for timing devices, on precise control of frequency.

7.17 Frequency reduction, whether spontaneous or induced, signals that the system is heavily loaded. In consequence frequency-sensitive relays are sometimes installed to protect a system from cascading failure (shut down). In Electricite de France, for example, these disconnect 20% of the load at each of the following frequencies: 49, 48.5, 47.75, 47 Hz. Relays are fitted at 20 kV levels on each outgoing feeder. The feeders are combed to find hospitals and industries which are believed to suffer most from interruptions in order to decide on appropriate frequency settings for the feeders.

Selective Demand Reduction

7.18 Feeders can of course be tripped by hand following instructions given by more or less centralized controllers. This is WAPDA's present method and has the advantage of requiring neither staff (substations are already manned) nor investment in equipment. It may be done on the basis of rotation of the 11 kV feeder disconnections so as to "spread the misery", by disconnecting feeders that are believed to have less important loads, or by disconnecting feeders of customers with least influence. Sometimes, as in West Pakistan, the overloading of certain transformers, particularly those at grid substations, narrows considerably the choice of feeders to be disconnected.

7.19 In many countries domestic storage water heating is singled out for selective disconnection, though this is coupled with a preferential price. Selective disconnection of 11 kV feeders obviously permits only a coarse discrimination between the different kinds of consumer. For example, a sample of 11 kV feeders with a predominance of private tubewell load had a median value of about 150 tubewells per feeder, but small industries and residential loads are intermingled.

1/ In one instance a recently completed cotton spinning mill had to replace the windings of practically all the electric motors during their first year of operation because of low supply voltage. However, the replacement windings were designed to be suitable for the low voltages actually supplied.

7.20 The use of under-frequency relays has already been mentioned but no-volt relays 1/ would have a similar task of disconnecting the outgoing 11 kV feeders whenever the system is overloaded. By briefly opening, one at a time, the 132 kV or 66 kV feeders running from main substations, it would be possible for the senior control engineers remotely to trip those 11 kV outgoing feeders at distant substations which are fitted with no-volt relays. Unfortunately, the senior control engineers cannot signal that the supply should be reconnected by the same method though the local staff at 11 kV substations could be required to seek telephone permission before restoring supply.

7.21 The use of telecontrol to control circuit breakers at 11 kV requires ripple receiving relays to be fitted to the 11 kV outgoing feeders. Also required would be central transmitting equipment injecting into the 132 kV or 66 kV system. The cost of these telecontrol devices will be set out later; it suffices to note here that the investment required would be fairly substantial. This sytem has, however, the greatest flexibility and the facility to command the disconnection and reconnection of load as required.

7.22 Timeswitches have been described in Chapter 6 and can easily be arranged (standard option) to omit the disconnection on certain days. They can be expected to be competitive with telecontrol provided the flexibility of the latter is not thought essential.

7.23 Another method of selective load control, but not requiring a technical device, is to seek the voluntary cooperation of large industries and public tubewells and to ask them to assist with load staggering arrangements. While there has been for some time a moratorium on new connections and extensions, the possibility of granting an extended supply provides WAPDA with a lever in securing the cooperation of the consumers concerned. Public tubewells have been asked to restrict demand over the daily peak period but the load curves in Chapter 4 indicate that such cooperation was not fully secured. While orders for staggering arrangements have been issued and also advertised from time to time in the press, industrial customers, when interviewed, generally professed ignorance of such arrangements Also WAPDA had no records showing how completely they were enforced. There seemed to be no central organization responsible for enforcing the rationing rules.

1/ A no-volt relay is an inexpensive device which recognizes that the supply has been interrupted. It is used in conjunction with a circuit breaker or motor-starting switch and disconnects supply whenever the supply is interrupted, even momentarily. The usual purpose is to prevent a restored supply causing machines to start again without the consumer being aware of any possible danger when a stationary machine suddenly rotates. However, in this case the function is to disconnect a feeder by recognizing that the supply has been momentarily disconnected. For this kind of duty the no-volt relay would have to have a small time delay to prevent its operation on every surge on the system.

7.24 Another administrative method of controlling load is to make use of the kilowatthour meter as a rationing instrument. In Norway, for example, whenever water power happens to be in very short supply, a penalty price is applied to consumers if they use more energy than they did last year. This operates as an automatic "fair-shares" rule, though the fairness is open to argument. Note that, while this method reintroduces the concept of pricing, it can be argued that the tariffs themselves remain essentially unchanged. Both this penalty and the moratorium on new connections employ the principle that past usage of electricity by a consumer justifies priority in the allocation of scarce resources: the doctrine of the regular customer.

Devices on Consumers' Premises to Control Load

7.25 The technical devices that might be employed on a consumer's premises to restrict demand or to disconnect supply for the whole or part of his installation are: (i) timeswitch; (ii) telecontrol receiving relay; and (iii) load limiter. To this list could possibly be added fuses if the inconvenience aspects were to be ignored.

Timeswitches

7.26 These have been described in Chapter 6. While it can be claimed that it is easier for the consumer to adapt to supply cuts originating from a timeswitch, in that such cuts will have a fixed, known regime, the obvious objection to such rigid control is that many supply cuts will be made unnecessarily. Nonetheless the use of timeswitches in this way should be given serious consideration if the aim is to restrict demand with the minimum investment. For example, public tubewells could be prevented by timeswitches from operating during peak periods. This should secure an effective cut in the public tubewell load.

Telecontrol

7.27 Telecontrol, also called centralized telecontrol, requires detailed consideration owing to its practical importance and frequent application. 1/ Telecontrol is a well-established method of operating switches in consumers' premises remotely from a central point without using control wires. The usual signal path is the supply system and the most frequently used signal is a ripple of audio frequency. The method is in consequence often called "ripple control", though telecontrol properly embraces signals such as direct current and impulses which could not be

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1/ The possibilities are many but in practice an installation tends to be confined to one or two applications. Suggested applications are:

(i) load control
(ii) meter register control
(iii) resetting signals for maximum demand tariffs, e.g. half-hourly
(iv) switching street lighting
(v) calling out emergency personnel, including fire and police

Where an economic justification for a proposed investment in telecontrol has to be based on more than one application, the difficulty of selling the proposed service to the various responsible authorities should be recognized.

termed ripples. By audio frequency is in practice meant a frequency in the band 150 to 1500 Hz.

7.28 The signal is injected at one or more points in the supply system where the energy is taken from the 50 Hz system and converted by a motor-generator set, or by a static-frequency converter, to the required signal frequency. As a rough guide, the output of the transmitter (motor generator or frequency converter) has to equal in kVA the maximum possible load in MVA at the point of injection. For example a 50 MVA power system requires 50 kVA of signal generation capacity.

7.29 Various signaling methods 1/ have been proposed but one frequently employed uses a single audio frequency transmitted as a series of pulses. The first one is a start pulse which is followed at a pre-determined time by an act pulse, where the action can be to switch OFF or ON. Up to 50 orders can be received and separately identified by the simplest receiver, but since ON and OFF operations are needed in pairs, effectively the control system in its simplest form provides control for up to 25 circuits. A seasonal time-of-day tariff with a 3-register meter, for example, has 2 circuits in the meter to be controlled (1-ON, 2-OFF; 1-OFF, 2-ON; 1-OFF, 2-OFF).

7.30 At the transmitter or injection point, the audio frequency generator is connected to the 50 (or 60) Hz system in such a way that the audio signal can easily enter the power system but the 50 Hz power is prevented from flowing back into the generator and destroying it. This coupling, particularly if the injection is carried out at 132 kV and above, is a substantial item of equipment.

7.31 The audio signal readily flows through the power system to the consumers' premises, passing through the various transformations, e.g. 66/11 kV, 11 kV/415-240 V. At any consumer's service position a receiver can be fitted which will disconnect on command the whole or part of the installation or perform any control or warning function. The receiver recognizes the audio frequency signal, rejects the power component at 50 Hz, and hopefully ignores unwanted signals collectively called noise. The first signal received, that is a recognized valid one, starts a miniature synchronous (constant speed) motor which measures time. This start pulse, half a second of the audio frequency, also causes every other receiver on the power system to start its synchronous motor. Some seconds later an act pulse is transmitted which is again recognized by all receivers but which causes the switch to open (or close) only in those receivers adjusted to that particular time delay. The sequence is, therefore:

1/ The Landis & Gyr system is described to provide a concrete example.

recognize start pulse

start constant speed motor

recognize act pulse

act if the time delay between
the two pulses is correct

After 30 seconds the motor stops and returns to its zero position ready to discriminate among any other signals received.

7.32 Figure 7.1 shows a standard receiver of the simplest kind. Overall it is a little larger than a household meter. The numbered wheel, 1-25, is set to control the acceptance or rejection of one of the 25 pairs of ON/OFF signals. More complex receivers are available which interpret a series of signals as a coded message and hence are able to provide far more than 25 ON/OFF operations.

7.33 The normal switching capacity of these receivers is 10 to 20 A (60 A contacts might be available) so that a supplementary circuit breaker to handle higher currents would often be required if the receiver were required to handle loads, rather than meter registers. The receiver is, therefore, best classed as light duty in its ability to control loads directly.

7.34 Apart from the flexibility of control, the receiving relay provides a service essentially similar to a timeswitch. Most studies of the economics of telecontrol compare the present value of the investment in telecontrol with that required to carry out the "same" function using timeswitches, with the flexibility of telecontrol regarded as a bonus. Some insight into this calculation is given by the following cost data, which are taken from Annex 13:

Injection equipment	US$750 per MVA of system demand
Receiver	US$ 35
Timeswitch	US$ 40

A naive (but illuminating) breakeven calculation, assuming that maintenance costs are not greatly different for the alternatives and that lives are much the same, runs:

$$\text{Breakeven density of application} = \frac{750}{40-35}$$
$$= 150 \text{ receivers per MVA of system demand}$$

7.35 For a 100 MVA system, for example, consideration should be given to the installation of telecontrol instead of 100x150 = 15,000 timeswitches. The paper by Michez and Schmucki, see Annex 13, puts the last figure as low as 1000. The cost differential between timeswitches and receivers is of course crucial to this calculation and to reach the lower figure, the following assumptions were made in that paper:

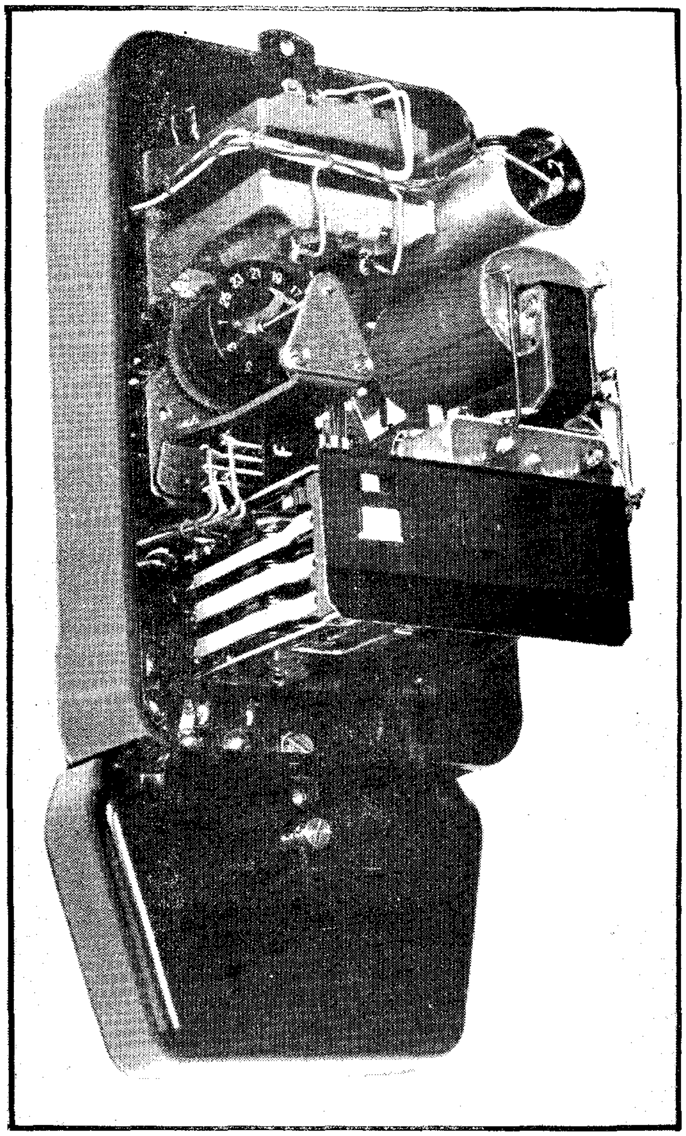

Figure 7.1 - A telecontrol receiver of the time-coded type capable of differentiating between 25 pairs of ON/OFF commands.

a. A timeswitch costs 1.6 times a receiver instead of 1.14 (40/35) as in Annex 13.

b. A timeswitch is amortized in 10 years but a receiver has a life of 15.

c. The maintenance cost ratio of a timeswitch/receiver is put at 33, with US$2 per annum for timeswitches and 6 US cents for receivers.

d. Nothing is said about maintenance of the central injection equipment.

7.36 In another example taken from the same paper, the pivotal figure in the calculation leading to an equally low breakeven guide density was the very significant addition of "setting time" to the annual costs of time-switches. Evidently, these timeswitches were being used for the (unsuitable) task of controlling some form of time-of-day rate with seasonal variation in the timing and hence had to be regularly adjusted. 1/

7.37 While there is room for differences of opinion, the breakeven guide density of 150 receivers per MVA of system demand is thought more realistic than the figure of 10. In particular, the view that the tele-control installation, including the central equipment, requires insignificant maintenance in contrast to the regular maintenance required for timeswitches is rejected. Annex 14 comments on some maintenance and operational difficulties experienced with telecontrol installations. Again the view that the purchase-price-ratio timeswitch/receiver is much greater than unity is discounted based on the realization that the receiver has to be precision engineered if it is to respond to valid signals and to reject spurious signals.

7.38 An overall view of this discussion leads to the following recommendations:

a. Below 100 controlled consumers per MVA of system demand give preference to timeswitch control rather than telecontrol, provided the flexibility of the latter is only desirable and not essential.

b. Above 200 controlled consumers per MVA of system demand (but see Annex 13 on the dynamic aspects) examine telecontrol.

1/ This unfavorable view of timeswitches and their maintenance and setting costs may also arise from the widespread use of escapement models in which the escapement has to run all the time. These models require regular maintenance and attention.

c. At an intermediate level pay particular regard to any engineering problems of the system concerned which might act as determinants.

This discussion is in the context of a well-maintained and staffed European electricity supply system.

7.39 However, for a developing country such as West Pakistan, perhaps a more stringent view should be taken of telecontrol in that some investment in central equipment will have to be made before any experience of the difficulties and benefits can be gained. Successful operation is questionable, especially if the supply frequency cannot be controlled. The signal frequency is tied to the supply frequency of 50 Hz and while the receivers permit some latitude, this might be exceeded. Again favorable experience with telecontrol applied to compact supply systems, especially towns, cannot be relied upon where the application is perhaps mainly to rural areas. Those engineering aspects which combine to give poor voltage regulation and high energy losses for the power frequency equally and adversely affect ripple signals.

7.40 The position might improve in that development work is still taking place and eventually costs may fall. One radically different method is the use of radio control. Radio receivers made by Motorola are being used by the Detroit Edison Company, Michigan, to control domestic water-heating. 1/ This approach avoids the need to add to injection capacity sympathetically with additions to system capacity. Another promising approach in the experimental stage is to use time-spaced pulses and electronic solid-state logic (as used in computers) to differentiate between wanted signals by a complex code. 2/

Load Limiters

7.41 Load limiters (circuit breakers) with settings related to current are operated by electromagnetic or thermal elements or a combination of

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1/ "Radio Control of Water Heaters and Distribution Station Voltage Regulators", J. B. Oliver, IEEE Paper No. 69-CP666-PWR, 1969. This paper describes the use of 200,000 radio control switches to disconnect storage water heaters and a further 800 to initiate voltage reduction on the system. Cost data are not available to permit comparison of radio control with ordinary telecontrol, though a radio receiver/decoder is believed to cost US$40.

2/ "Solid State Remote Control System", J. W. Townsend, Electrical Power Engineer, June 1970.

both which open the circuit when a given current is exceeded. If this happens the load limiter can easily be reset to restore supply by the consumer pushing a button once he has sufficiently reduced his demand. The load which causes the circuit breaker to open is not precisely determined and there is a time delay before the device operates. However, to simplify discussion it will be assumed that load limiters act precisely at the nominal setting value and act immediately.

7.42 Two kinds of load limiters are available. One kind of limiter has to be replaced to alter the setting, whereas the other, see Figure 7.2, has a few adjustable settings: for example, 5, 10, 15 A or again 15, 25, 30 A, or in the largest size 40, 50, 60 A. The non-adjustable version costs about US$3 whereas the adjustable one costs US$10. Yet another kind is often used in France 1/ where adjustable load limiters have the additional and important function of protecting the consumer's installation from earth leakage and are, therefore, fitted with a sensitive earth leakage device.

7.43 Load limiters are inexpensive devices and since they ostensibly limit load are worthy of serious consideration in any study of load control. However, as described in Annex 9, these devices are widely employed as a basis for levying the fixed charge of a two-part tariff or as the basis for a single-part tariff without an energy meter. The first question to be answered, therefore, is whether a load limiter used in this tariff context has any significant load limiting effect.

7.44 This question cannot be firmly answered since load research data are not available on matched groups of consumers where the control group have energy meters and the treatment group have energy meters plus load limiters. Conjectured load data are of little value, because either a significant (to investment) load cut or an insignificant cut can be brought about by manipulating the assumptions. For example, for British households, the following claims could be made in the absence of load research data:

a. the system peaks in winter when it is cold and dark;

b. households contribute to that peak;

c. when they are cold, or are short of other fuels, they will turn to electricity for heating to a greater extent than usual;

d. this action will increase both (i) the system peak and (ii) the individual's peak;

1/ Electricite de France or an associate issue a performance specification and obtain supplies from seven local manufacturers.

e. hence restricting the individual's peak to its normal level will significantly reduce investment in system capacity.

7.45 This kind of reasoning could easily be extended to other consumers on other power systems. The essence is that sometimes consumers need more electricity and that, under certain circumstances, these enhanced needs will coincide with system peak. However, the proposal is not to reduce the individual's demand at such times, for example by doubling the price using telecontrol and a 2-register meter, but to limit the individual's demand at all times. The weakness of the argument lies in item d.(ii) where it is claimed that an increase in system peak coincides with an increase in the individual's peak. Extensive load research in Britain 1/ on the problem of domestic electric heating using radiant electric fires, which usually equal in installed load the total generating capacity, on the whole firmly rejects conclusion e. 2/ and assumption d.(ii).

7.46 Based on recorded demands of individual domestic consumers, studies have shown, fairly conclusively, that the British domestic consumer on ordinary tariffs makes his individual maximum demand across the seven days of the week, and across the waking hours of the day, almost at random. Certainly the randomness, i.e. lack of a coherent pattern, is sufficient to refute any suggestion that the domestic consumer should properly have his individual maximum demand restricted as an investment-saving device.

7.47 However, these data relate to consumers on a winter-peaking system with average annual consumptions between, say, 3,000 kWh and 15,000

1/ For example, see Utilization Research Reports Nos.

55) Characteristics of the Socket Outlet Load in
) Domestic Premises
)
56) Diary of Household Heating
)
57) A.G.B. Home Audit - Use of Fuels for Space Heating
) and Water Heating.
)
58) Cold Snap Survey

Electricity Council, London. Circulation is restricted. In one volume.

Also see "Research into Unrestricted Domestic Space Heating" J.G. Boggis, Electrical Review, 21st June, 1968.

2/ Within reason, of course: if individual demands were to be sufficiently limited then system demand would be reduced. That the sum of zeros is zero provides no clue, however, to the behavior of electricity consumers granted feasible restrictions.

Figure 7.2 - An adjustable current-operated load limiter with settings of 5,10 or 15A. The "button" to restore supply is in this example a toggle.

kWh. Obviously they cannot apply in West Pakistan to any proposal to limit residential demand. Nonetheless they demonstrate that conjecture is a poor substitute for measurement, and that the essential "obvious" assumption that limiting individual demand reduces investment in system capacity should not form the basis of investment in load limiters without substantiating measurements.

7.48 In France, where load limiters are used extensively as the basis of the fixed charge of a domestic two-part tariff, no claim is made by Electricite de France that load control is achieved. They report that limiters (disjoncteurs) very rarely indeed operate on overload, but that the tariff and the price applied to the limiter setting might have a depressing effect on the growth of domestic electricity.

7.49 The second question to be answered is whether load limiters could have any application outside the tariff context. For example, could they be installed in homes, in factories and on farms to limit demand to some level which has been fixed by an authority such as WAPDA? If the aim is to limit individual demand as may happen where a large industrialist is supplied from a grid sub-station and has agreed not to take up too much of the local capacity, then obviously a load limiter 1/ could be used to prevent the consumer breaking his contract, though precisely the same effect could be obtained by a penalty on the maximum demand charge for exceeding an agreed level. Owing to the starting currents taken by the electric motors, there is little question of installing load limiters for the control of private tubewells and in any case these loads are usually of the all-or-nothing variety with the farmer having little or no control over his electricity demand.

7.50 For residential consumers using only electric lighting, load limiters could be installed to restrict the growth of demand and insofar as the lighting demand is likely to be coincident with the system peak, it could be claimed that this approach would reduce investment in system capacity. However, this kind of proposal, if seriously made, ignores the possibility that the other uses to be made of electricity beyond the first one or two lights might consist of applications outside the peak hours. The consumer is to be threatened with disconnection should he exceed the setting on the current limiter, whereas the supply system at that time might be fully capable of meeting the proposed increment of demand.

1/ It would have to have an extended time delay to prevent frequent operation on motor starting currents and would, therefore, be priced at more than US$10. There are other technical issues which would inflate the price.

7.51 Load limiters could be prevented from operating at certain times (by-passed) by means of timeswitches or telecontrol. This combination of devices, costing perhaps US$50 per consumer, would circumvent the objections of the previous paragraph. The combination is analogous to a time-of-day tariff where the tariff pressure at times of high system demand has been replaced by pressure on the rate of utilization when and only when it is required. The combination device also makes it possible to select a much lower limiter setting than would be possible with continuous operation of the limiter. The cost of US$50 seems high in relation to only a partial load reduction if the application is to domestic consumers.

Social Costs

7.52 This chapter has so far discussed the various methods of physical rationing, mainly using technical devices, with the assumption that load control is not to be weighed against the alternative of providing additional system capacity: supply capacity was taken to be fixed. There is clearly a need, however, to show under what circumstances expenditure on load control devices would be thought to be more desirable than investment in capacity. These alternatives are, of course, to be compared on a basis of equal effectiveness in meeting/suppressing demand increments, in excess of the supply capacity.

7.53 Equal effectiveness is a difficult concept if pursued in detail. 1 MW suppressed at consumers' terminals has the benefit of zero transmission losses. But 1 MW of generating capacity can be seen to have a tangible output, whereas 1 MW of demand-cut will lead to no investment savings until the cut is proven and has found its way through the demand forecasting procedures. 1/ Again a load cannot be cut if it is not present, so that the hoped-for cut of 1 MW might not always prove to be effective. 2/

7.54 Granted, however, that the problem of what is a megawatt in this context has been overcome, the two main approaches to physical rationing could be compared with the provision of additional generating plant in accordance with the following formulation:

Let C_1= Present worth of social product lost by repressing selectively 1 MW of load

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1/ But distributors often buy electricity in bulk from a generating authority under the terms of an annual maximum demand tariff. Such distributors therefore regard load control, especially telecontrol of domestic water heating, as giving rise to immediate tangible savings. The generating authority might not share this view.

2/ Conversely, a cut might grow in depth over the years with a given investment in rationing devices.

C_2= Present worth of social product lost by shedding unselectively 1 MW of load

C_3= Present worth of resources used by providing 1 MW of generating capacity

h = Cost of hardware associated with selective load control of 1 MW

Then, we postulate

$$C_3 > C_2 > C_1$$

But social cost of selective load control is $C_1 + h$

and $$C_3 > C_2 \lesseqgtr C_1 + h$$

Only if $$C_3 > C_2 > C_1 + h$$

should selective load control be considered as an alternative to unselective load control.

7.55 In this formulation, selective load suppression requires hardware to discriminate between consumers and possibly between peak and offpeak times, whereas unselective load shedding is achieved, as at present, by manually tripping circuit breakers at grid substations. The final inequality says that investment in hardware physically to ration consumers is only worthwile if the social costs with unselective shedding exceed those with selective suppression (load control) by a margin greater than the cost of the hardware.

7.56 Estimates of "the present worth of social product lost" under the two regimes have not been made. However, interviews with industrialists tended to show that the degree of unselective load shedding now applied was well tolerated. No clear-cut solution to the problem of excess demand has been brought out by this study of physical rationing devices. However, as an opinion-forming guide, the following ranking of load-control schemes is thought to be broadly appropriate:

Price rationing with temporal pricing.
Price rationing with existing metering.
Unselective load shedding.
Selective load shedding using timeswitches or telecontrol.
Restraint by load limiters.

WEST PAKISTAN

WATER AND POWER DEVELOPMENT AUTHORITY

REPORT ON LOAD CONTROL STUDY

ABSTRACT FROM TERMS OF REFERENCE

1. The Bank is interested in trying to determine through a practical case study the responsiveness of power demands in a developing country to pricing policy and other commercial arrangements and the feasibility and effectiveness of controlling the load through engineering devices. In addition to helping the particular country concerned, it is hoped that such a study will serve the wider purposes of enabling the Bank to provide better advice to borrowers on methods of raising system load factor economically and to improve its techniques for appraising power projects.

2. West Pakistan and specifically the supply area of the Water and Power Development Authority (WAPDA) has been selected for this study in agreement with the Government and WAPDA. WAPDA has been experiencing increasing difficulty in meeting the demand on its system for various reasons, including shortage of capital in the face of rapidly growing load, and the quality of service has been deteriorating in consequence. The role that pricing or other control measures could play in alleviating the situation calls for investigation. Moreover, the pattern of system capability is changing with the growing amount of storage hydro capacity, leading to wide seasonal variations in the costs of supplying the peak demand; it is desirable therefore to examine the extent to which the shape of the load curve might be altered to match the changing pattern of supply by commercial arrangements or other devices.

3. You should therefore make a study of the economic, technical and administrative feasibility of the various methods available for controlling the load on the WAPDA system. The main tasks to be covered during the study will be as follows:

(a) to identify loads which might be adjusted in response to differential pricing or other commercial arrangements such as supply agreements with the load cut-off or contingent load shedding (with or without warning). This will involve detailed discussion with selected consumers (industrial, commercial and agricultural) and investigation of the alternative types of power consuming equipment and of energy available to them;

(b) to estimate the magnitude and timing of changes in the global pattern of power demand which might result from the application of such pricing or other commercial techniques;

(c) to develop data on the costs of power supply at different times of day and seasons and in different areas. (A computer model in the Bank of the WAPDA system will help in generating information about bulk supply costs or different shapes of load curve under different reservoir conditions and you should obtain data in Pakistan on transmission and distribution costs);

(d) to review the various technical methods of load control, such as off-peak metering, ripple control and load limiters, with particular reference to the costs and feasibility of applying them in the WAPDA system;

(e) to determine whether the savings from the adoption of the load control measures referred to in (a) and (d) above would outweigh their costs; and

(f) to make recommendations regarding the specific measures which should be adopted by WAPDA to adjust demand to system capability, and how these measures should be implemented.

4. You should arrive in Lahore on or about June 4, 1970. En route you should visit the Electricity Council in London on June 1 and Electricite de France in Paris on June 2 for briefings which have been arranged on their experience of methods of load control.

5. During the course of the study Mr. Boggis may also be required to visit Djakarta 1/ or some other developing country where load limiters have been used extensively and possibly an area where ripple control has been used.

1/ Another engineer went in October and reported on his findings to Mr. Gavin E. Wyatt on November 30th.

ANNEX 2

AN ENQUIRY INTO TAXATION APPLIED TO

ELECTRICITY ACCOUNTS

The questionnaire for the enquiry of 1965 asked for information for each country on any taxes that were imposed on L. V. consumers' electricity accounts.

It was understood that the taxes referred to were those explicitly charged to the consumer when drawing up his account and not taxes that the electricity producing and/or distributing undertakings had to pay in respect of certain aspects of their activities such as personnel employed, installed capacity, etc. or as tax on turnover or profits.

The following countries reported no such taxes were levied:

Austria	Hungary	Portugal
Finland	Ireland	Switzerland
Great Britain	Poland	Yugoslavia

Other countries replied as follows:

Country	Tax Rate	Type of Tax
Algeria	7%	Production Tax
Denmark	12.5%	Value Added Tax (VAT)
Spain	1.5-10%	Transfer Tax ("Derechos Reales")
Greece	6.5-10%	5% Turnover Tax plus Stamp Duty
Norway	N.A.	Fixed Amount per kWh
Sweden	7%-10%	Fixed Percentage per 40,000 kWh or more
West Germany	11%	VAT
Belgium	7%	Taxe de Transmission
Netherlands	4%	VAT
France	15%	VAT plus Municipal or Departmental Taxes
Italy	N.A.	Municipal, Government and General Receipt Tax (4%)

N.A. - Not available

SOURCE: "The Structure of Low Voltage Tariffs and the Degression of Low Voltage Tariffs for Domestic Use", Report by Jean Bossaert, Cannes Congress September 1970, International Union of Producers and Distributors of Electrical Energy (UNIPEDE).

EXCERPT FROM DRAFT FOURTH FIVE YEAR PLAN,

POWER SECTOR, JUNE 1970

Progress under Third Plan:

4. Power facilities in West Pakistan during the Third Plan continued to expand in spite of the severe power crisis in the first half of the Plan period due to the failure of major thermal power station at Multan (260 MW), delay in the completion of the Lyallpur power station (132 MW) and Hyderabad extension (23 MW) and shortage in number of grid stations and undercapacity of transformers. Some of the features of this expansion are: installed capacity from 1,000 MW to 1,920 MW, total generation from 3610 million kilowatt hours to 6,700 million kilowatt hours inclusive of captive industrial generation, per capita generation from 70 units to 112 units, length of transmission and distribution lines 11 kV and above from 13,500 miles to 38,000 miles, number of consumers from 0.84 to 1.48 million.

5. In spite of this expansion, however, complaints about the poor quality of service not only persisted but increased. Deficits appeared for the first time in the revenue accounts of WAPDA. It has, therefore, become imperative to improve the efficiency of the public utilities in order to improve the level of reliability and the quality of service to consumers.

Objectives:

6. The objectives during the Fourth Plan will be:

a. to remove the deficiencies which emerged during the Third Plan period;

b. to sustain economic growth by meeting the increasing needs of the productive industries; and

c. to strengthen social services and improve the economic efficiency of the rural areas by undertaking rural electrification in conjunction with tubewell electrification.

Strategy:

7. Greater emphasis will be placed on improving the operating efficiency of the public utilities, particularly that of the Water and Power Development Authority. Efficiency can be introduced by creating proper balance between generation and marketing facilities, reducing power losses (recorded as high as 32% of total generation) and employing better operating and maintenance techniques (the failure at the Multan Power Station was due to inefficient operation and poor maintenance). The Plan attempts

to achieve a balance between generation and marketing facilities through higher allocations to distribution than in the previous plans. WAPDA on the other hand will have to take concerted action to reduce the losses in the system and to evolve better operating and maintenance techniques and to improve its distribution system. Emphasis will be placed on creating more grid stations with shorter feeder circuits, renovating existing distribution mains through replacement of transformers and installation of shunt capacitors and feeder voltage regulators to stabilize voltage to consumers. These works will have to be undertaken simultaneously with extension works to give new connections for spreading the social benefits.

8. Serious doubts have been expressed on the ability of WAPDA to shoulder the responsibility of retail distribution of power along with the construction of major power and irrigation facilities. Consideration, therefore, should be given to the bifurcation of the power wing from WAPDA or at least the separation of retail distribution and its handing over to an autonomous power corporation in the province.

9. The different zonal systems which are at present isolated need to be interconnected by transmission lines capable of carrying large quantums of power in order to meet future needs at minimum costs. During the Fourth Plan the Northern system is proposed to be integrated with Upper Sind system by construction of E.H.V. interconnection between Gudu and Lyallpur and the lower Sind system with Karachi system by permanent 132 kV lines. The integration of the northern region with the southern region by means of the Gudu-Karachi E.H.V. link has been postponed to early Fifth Plan because:

(a) surplus hydro power from North becomes available in appreciable quantities justifying E.H.V. interconnection only after the commissioning of Tarbela in late 1975; and

(b) optimum utilization of Tarbela power is not possible till E.H.V. interconnection between Tarbela and Lyallpur is energized in 1975/76.

The Gudu to Karachi E.H.V. link, however, should proceed directly along the right bank of the Indus. It should be made to pass over Lakhra coal field which will facilitate the interconnection of a coal based station with the national grid later in the future. Besides, on this route the transmission line will traverse an area north of Karachi which has less alkalinity and salinity in the air compared to the Karachi-Kotri area.

10. Sizeable agricultural load has emerged during the Third Plan which contributes to large seasonal variations in peak demand particularly in WAPDA's Northern Grid system and Upper Sind. This seasonal variation for the integrated Northern Grid and Upper Sind system in 1975 is expected to vary from 1,355 MW in April to 1,520 MW in September which would include 95 MW of public tubewell load in April and 204 MW in September. It has been observed that the critical month in respect of supply is April when

the output of the hydroelectric power stations is greatly reduced due to fall in the reservoir water levels and not the month of September when the maximum demand occurs because the increase in demand is taken care of by the increased capability of the hydel power stations which is maximum at that time. Accordingly, the Plan program for additional generation for the Northern Grid and Upper Sind has been evolved after examining the computer run offs on a monthly basis in respect of generation capability versus demand with special reference to the month of April for average water years. Taking cognisance of the fact that the major generation scheme involving installation of a 200 MW unit at Gudu power station is progressing very slowly, the system capability has been tested against demand without this unit but including availabilities from ongoing Mangla units 5 & 6, Gudu units 1 & 2, and new Mangla units 7 & 8. Under the above condition, in April 1973-74 the system capability will be 1,448 MW, firm capability 1,348 MW as against peak load of 1,243 MW inclusive of 95 MW on account of public tubewells, which could be subtracted from the peak load. The reserves available are considered sufficient for the annual maintenance of generating units and spinning capacity inter alia for voltage and frequency control. In April 1974-75, however, the system capability and firm capability will be the same but peak load is estimated to reach 1,355 MW, 7 MW more than the firm capability if no allowance is made for shedding public tubewells. The position will be slightly tight for about 3 months if Gudu Unit 3 is delayed but with proper planning of system operation in respect of annual maintenance etc., it could be tided over till the advent of Tarbela Power in June, 1975.

11. The Hyderabad-Karachi pooled system in the Southern region will be interconnected with the Northern region in early Fifth Plan and as such the strategy for the Fourth Plan involves balancing the firm capability of the pooled system with the system demand in such a manner that after interconnection with the Northern region the excess on gross capacity matches the import from the North up to at least the mid-Fifth Plan period. This would require the commissioning of a 200 MW power station in the pooled system by 1974. Accordingly, the Plan includes investment for commissioning of a 200 MW power station at Karachi in the private sector not only because of cheaper sources of generation at Karachi but also because of financial constraints in the public sector program for the Power Sector in West Pakistan.

12. Peak lopping i.e. maximizing energy at the expense of demand capacity merits serious consideration during the Fourth Plan particularly in the Northern region. This would enable postponing investment in additional units at Gudu and possibly the later units at Tarbela. Peak lopping could be achieved by encouraging energy usage during off peak load hours through tariff incentives and/or by forced restricted hours of supply by installation of timeswitches at the consumers' premises. The additional cost involved in double metering and timeswitches will be negligible in comparison to capital cost of additional generating equipment.

13. Lag in the growth of agricultural and sales during the Third Plan was not only due to load shedding but also indicated widespread theft of energy by meter tampering, wrong reading, etc. With the introduction of double metering this danger may increase further. Obviously, there is an urgent need to eradicate these malpractices. An independent inspection squad could be created in WAPDA for inspection of consumer premises and checking of meter readings to reduce the losses. Cooperation from the consumer will be essential. The existing malpractices, however, should not deter WAPDA from embarking on a program of double metering at least in selected areas on an experimental basis to effect peak lopping, which besides postponing capital investment will also result in reduction of energy price, particularly the fixed part of the two part tariffs.

Program:

14. The program in the public sector provides for the speedy completion of the following on-going and new generation schemes:

Gudu units, 1& 2	220 MW in 1971-72
Gudu unit, 3	200 MW in 1974-75
Mangla unit, 5	100 MW in 1970-71
Mangla unit, 6	100 MW in 1971-72
Mangla unit, 7	100 MW in 1972-73
Mangla unit, 8	100 MW in 1973-74
Tarbela 1 & 2	350 MW in June 1975
Quetta 3 & 4	15 MW in 1973-74

15. The progress is behind schedule in respect of Gudu unit 3 of 200 MW and the commissioning of this set during the Plan period appears doubtful. It is possible, however, that the progress on this project may improve during the currency of the Plan period. In the private sector the Plan provides for the commissioning of a 200 MW conventional power station at Karachi. The need for additional generation at Karachi has been established on the basis of the planning criteria discussed in the strategy. The following table summarizes the different sources of generation which are included in the program:

WEST PAKISTAN
Installed capacity by source of generation

	1965	1970	Achievement 1970	Target 1975
Hydel	269.7	669.7	667.8	1,417.8
Steam (plus Gas turbines)	487.3	1,190.0	1,028.7	1,437.7
Diesel	58.0	28.0	46.9	20.0
Nuclear	-	125.0	-	125.0
Sub-total:	815.0	2,012.7	1,743.4	3,000.5
Captive Industrial Capacity	185.0	150.0	180.0	150.0
TOTAL:	1,000.0	2,162.7	1,923.4	3,150.5

16. Provision has been made for the retirement of the old steam power stations at Lyallpur (13 MW), Sahiwal (6 MW) and Hyderabad (5.7 MW). No additional diesel capacity is planned to be added and the existing capacity has been reduced substantially to cover the retirement of obsolete diesel units for reasons of economy and availability of power from large central generating stations.

17. The allocation required for generation in the public sector is Rs 708 million (including Rs 493.0 million on account of on-going generation schemes) which constitutes 28% of the total allocation.

18. Power planning in West Pakistan has a space dimension and the demand and availabilities discussed in the strategy become relevant only when the different markets are interconnected by transmission lines. Although the program provides for E.H.V. interconnection between Gudu and Lyallpur, it is doubtful that the line would be commissioned during the Plan period. It is necessary to synchronize the completion of this line with the commissioning of Gudu Unit 3 of 200 MW. The existing and under-construction 132 kV lines from Gudu to Dharki in the north and Sukkur in the south, however, will be commissioned during the Plan period which would ensure the absorption of the output of the Gudu Units 1 & 2.

19. The program provides for the speedy completion of the transmission lines associated with Mangla Dam Units 1 to 4 comprising 220 kV double circuit line from Mangla to Kala Shah Kaku, single circuit 220 kV line on double circuit towers between Kala Shah Kaku to Kot Lakhpat and 220 kV double circuit transmission line from Kala Shah Kaku to Lyallpur. These lines were scheduled to be completed in November, 1968, but due to unforeseen circumstances were delayed and only certain sections will be energized by the end of the Third Plan period. It is important that strengthening of this system is not similarly delayed and effort should be made to phase this work in a manner which would synchronize with the phased commissioning of the under-erection and planned Mangla Units 5, 6, 7 and 8 provided under the generation program. The strengthening would involve construction of a second double circuit 220 kV line between Mangla and Kala Shah Kaku and 220 kV double circuit line between Mangla and Wah besides stringing the second circuit on existing double circuit towers between Kot Lakhpat and Lahore.

20. Since the first two units at Tarbela are scheduled to be commissioned by June, 1975, and since it does not appear possible at this time to interconnect Tarbela with Lyallpur by that date, the program includes construction of 3 - 220 kV transmission lines between Wah and Tarbela to be completed by June, 1975. It is important, however, to plan, finance and implement the E.H.V. interconnection between Tarbela and Lyallpur as early as possible not only to utilize the output of the later Tarbela Units, but also to give a meaning to the integration of the Northern region with the Southern zone and Karachi. Provision has been made in the Plan to initiate the construction of this vital link.

21. The allocation to transmission stands at Rs 569 million, of which Rs 419 million will be on account of the on-going schemes of Mangla Dam transmission and 500 kV E.H.V. interconnection between Gudu and Layallpur and Gudu and Karachi. The allocation for transmission constitutes 22% of the total outlay in the public sector for power development.

22. During the Third Plan the service was marred by load shedding and abnormally high system losses. The amount of load shed during the months of July and August 1968 was of the order of 0.9 million kWh per day. (The total amount of load shed during these two months was 56 million kWh.) The parameters by which the quality of service is measured viz. frequency and voltage conditions at the consumers' premises left much to be desired. Another serious aspect has been the increase in system losses as percentage of energy generated (22% in 1960, 26% in 1964 and 32% in 1968).

23. Failures of existing power stations, delays in completion of new power stations and transmission facilities, inadequacy of the distribution system particularly the shortage of grid stations, longer than permissible lengths of feeder circuits and under capacity of distribution mains and transformers contributed to a large extent to load shedding, poor quality of service and increase in system losses. The distribution program, therefore, includes installation of 26 new 132 kV, 39 new 66 kV and 1 new 33 kV substations, extension of 30-132 kV and 56-66 kV substations, conversion of 25 substations from 66 kV to 132 kV in addition to the 38 grid stations for which orders have already been placed. It also includes the renovation of existing distribution mains and replacement of transformers not only to improve the reliability and quality of service but also to reduce the abnormally high system losses, a large percentage of which occurs in the distribution system.

24. The distribution program besides the above work aims at providing service connections to 630,000 new consumers in WAPDA system which would bring the total number of consumers in the province to more than 2 million by 1975.

25. The rural electrification program has been adopted in conjunction with tubewell electrification largely as a social service. Since it cannot be regarded as a paying commercial proposition, care has been taken to see that this program does not impose excessive financial handicaps on the power industry. Accordingly, only 1,000 villages are planned to be electrified during the Fourth Plan period.

26. The financial outlay on distribution will be of the order of Rs 1,250 million -- about 50% of the total capital outlay of Rs 2,527 million for Power Development in the public sector during the Fourth Plan. The physical and financial targets of the program are presented in Annexes.

OUTLINE OF A METHOD OF RESOLVING THE TOTAL LOAD INTO CONSUMER CLASS COMPONENTS

Collection of Data

The following data have to be collected for a number of sub-areas which together cover the total area. A sub-area describes any supply catchment area for which demand and annual consumption data are available or can be closely estimated.

(i) the annual kWh-sales of electricity (for the year embracing the days being analysed) for each of the class components: e.g. domestic, commercial and industrial.

(ii) half-hourly potential demands[1/] on days selected for analysis.

These data can be expected to be available as by-products of the accountancy system for a comprehensive supply network covering a country. Smaller electricity undertakings may find it inconvenient to use the method owing to insufficient sets of data, i.e. few sub-areas.

Component annual consumptions are used as the regressors, and the potential demands for each half-hour are broken down by multiple regression techniques into their class components. By repeating the process for each half-hour of each day the component daily load curves are delineated.

Preparation of Data for Regression Analysis

It is advisable to scrutinize the demand and consumption data for obvious errors. The demand curves can be expected to vary smoothly for each sub-area from half-hour to half-hour on any day and to show fairly systematic variations between the days for a given half hour. The consumption data for any sub-area should show, in general, a consistent pattern of growth when compared with data for earlier years. Later on when the analysis has been completed, it may be necessary to repeat the scrutiny, paying attention to those parts of the data which the analysis suggests might be in error.

The checked data are then presented to the computer as an observation matrix, with the potential demands as explained variables, the annual component consumptions as regressor variables, each sub-area (k-suffix) providing a set of observations.

The computer can be programmed to group minor groups of consumers with major ones to reduce the likelihood of estimating demand curves for minor components where the demand level is swamped by the variance. In such cases negative values sometimes arise which, of course, are hard to defend as realistic estimates. As an example of the procedure, the following seven consumer groups:

1/ **Potential demand is the demand supplied plus any allowance for demand reduction.**

1. domestic
2. farms
3. combined premises, e.g. shops with flats
4. commercial
5. public lighting
6. industrial
7. traction

can be combined to form three class components:

(1) + (2) + (3)/2 called "Domestic"

(4) + (5) + (3)/2 called "Commercial"

(6) + (7) called "Industrial"

In each case the leading group is dominant in England and Wales and probably in many other supply systems, i.e. 1, 4 and 6.

Another kind of transformation of the data, which can sometimes be found helpful, is to scale down, or up, any entire set of demand and consumption data arising from any sub-area using a constant scale factor for that sub-area but different scale factors between the sub-areas. The aim is broadly to equalise the variance of the data, bearing in mind that the multiple regression method assumes that each observation (each sub-area) can be regarded as coming from a pool of observations of constant variability. In fact, the data arise from accidental dispositions of bulk-supply metering and consumers' accounts areas and in consequence it might be useful to challenge the concept of constant variability.

Class Effective Annual Load Factors

The demand data are measured at bulk supply points whereas the annual consumption data are measured at consumers' terminals. For the purposes of the regressions this makes no difference whatsoever but if the estimated component demands are to be translated into annual load factors at a given point in the system some estimate of the losses (for each class) over the system must be made. The total energy purchased at bulk supply points can be compared with the aggregate kWh-sales to all consumers, after allowance for any direct consumers who take special supplies from a bulk supply point. This gives an overall percentage increase to be applied to the kWh-sales in calculations of load factor, but in practice the percentage increase is varied for each consumer class above and below the overall figure, broadly in accordance with the proportion supplied at low voltage.

Mathematical Description

This description relates to any given half-hour.

Notation

N	=	Number of sub-areas into which the total area of supply is divided.
P_k	=	Demand for sub-area k.
n	=	Number of components into which the total demand is to be resolved.
X_{ik}	=	Annual kWh-sales of component i in sub-area k.
b_i	=	Regression coefficient of component i.
e_k	=	Error term in the regression equation.
$F = \sum_{k=1}^{N} e_k^2$	=	Sum of squares of the errors.

Further Notation for Constraint

X_{it}	=	Annual kWh-sales of component i for the total area.
P_t	=	Known total demand to which component demands have to sum for each half-hour.
λ	=	Lagrange undetermined multiplier.

Regression Analysis

The regression model used minimises the error sum of the squares in the equation.

$$\boxed{P_k = b_1X_{1k} + b_2X_{2k} + \quad \dots \quad + b_nX_{nk} + e_k} \quad . \quad . \quad . \quad . \quad (1)$$

Equation 1 relates the demand for each sub-area to the sum of the estimated component demands. Each component demand is described by a coefficient b_i, which is the same for every sub-area and which estimates the component demand as the product b_iX_{ik}. The coefficient has the dimension of MW/GWh or, equally, kW/1,000 kWh. It thus has an immediate (reciprocal) connection with annual load factor, effective at the given half-hour.

In so far as the system has losses, the annual consumption data measured at consumers' terminals and the bulk-supply point demand data are not completely consistent with each other and with the usual definition of annual load factor. However, as already mentioned, a correction for losses can be made. That is if we ignore losses for the time being:

Effective annual load factor of i-th component in sub-area k

$$= X_{ik}/(P_{ik} \times 8.760)$$

$$= X_{ik}/(b_i X_{ik} \times 8.760)$$

$$= 1/(b_i \times 8.760) \qquad \dots \dots (2)$$

Equation 2 shows that the regression model assumes an annual load factor (ignoring losses) which is constant for a given component over all sub-areas in relation to the demand for any given single half-hour. This assumption, repeated for each half-hour, also leads to the concept of invariant shapes for the component load curves on any given day among the many sub-areas. The error term e_k arises to the extent that the assumption of constant effective annual load factor is not strictly tenable.

The object is to minimise F, the error sum of squares, with respect to $b_1, b_2, \dots, b_n$

subject to the constraint

$$\boxed{P_t = b_1 X_{1t} + b_2 X_{2t} \quad \dots \quad + b_n X_{nt}} \qquad \dots \dots (3)$$

which ensures that the sum of the component demands for any half-hour is equal to the known system total demand P_t

We have

$$F = \sum_{k=1}^{N} e_k^2 = \sum_{k=1}^{N} \{\sum_{i=1}^{n} b_i X_{ik} - P_k\}^2 \quad \text{from equation} \dots \dots (1)$$

so that

$$\frac{\partial F}{\partial b_j} = \sum_{k=1}^{N} 2X_{jk}\{ \sum_{i=1}^{n} b_i X_{ik} - P_k\} \qquad \dots \dots (4)$$

for all i : i = 1, ..., n

The expression for F has been differentiated in equation 4 to find the values of b_i which give the minimum error of squares, i.e. min.F. For example, for one of the b_i coefficients, say b_j, we have an expression in equation 4 which would normally be put equal to zero. However, the constraint, equation 3, modifies the usual method of finding a minimum. By Lagrange's Theory of Undetermined Multipliers, at the constrained minimum

$$\frac{\partial F}{\partial b_j} + 2\lambda \frac{\partial}{\partial b_j} \left\{ \sum_{i=1}^{n} b_i X_{it} - P_t \right\} = 0 \text{ for all } i : i = 1, \ldots\ldots\ldots\ldots, n$$
$$\text{and for each } j : j = 1, \ldots\ldots\ldots, n$$

and $$\sum_{i=1}^{n} b_i X_{it} = P_t \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5)$$

Hence the following n+1 equations apply where λ is the Undetermined Multiplier,

$$0 + b_1 X_{1t} + b_2 X_{2t} + \ldots + b_n X_{nt} = P_t$$

$$\lambda X_{1t} + b_1 \sum_k X_{1k}^2 + b_2 \sum_k X_{1k} X_{2k} + \ldots + b_n \sum_k X_{1k} X_{nk} = \sum_k X_{1k} P_k$$

$$\lambda X_{2t} + b_1 \sum_k X_{2k} X_{1k} + b_2 \sum_k X_{2k}^2 + \ldots + b_n \sum_k X_{2k} X_{nk} = \sum_k X_{2k} P_k$$

$$\cdot \qquad \cdot \qquad \cdot \qquad \cdot \qquad \cdot$$

$$\cdot \qquad \cdot \qquad \cdot \qquad \cdot \qquad \cdot$$

$$\lambda X_{nt} + b_1 \sum_k X_{nk} X_{1k} + b_2 \sum_k X_{nk} X_{2k} \ldots + b_n \sum_k X_{nk}^2 = \sum_k X_{nk} P_k$$

$$\ldots\ldots\ldots\ldots \quad (6)$$

These equations can be written more compactly by using matrix notation.

We define

$$X_t = \begin{bmatrix} X_{1t} \\ X_{2t} \\ \cdot \\ \cdot \\ \cdot \\ X_{nt} \end{bmatrix} \quad X = \begin{bmatrix} \bar{X}_{11} & \bar{X}_{12} & \cdots & \bar{X}_{1n} \\ \bar{X}_{21} & \bar{X}_{22} & \cdots & \bar{X}_{2n} \\ \cdot & \cdot & & \cdot \\ \cdot & \cdot & & \cdot \\ \cdot & \cdot & & \cdot \\ \bar{X}_{n1} & \bar{X}_{n2} & & \bar{X}_{nn} \end{bmatrix} \quad b = \begin{bmatrix} b_1 \\ b_2 \\ \cdot \\ \cdot \\ \cdot \\ b_n \end{bmatrix} \quad P = \begin{bmatrix} \bar{X}_1 P \\ \bar{X}_2 P \\ \cdot \\ \cdot \\ \cdot \\ \bar{X}_n P \end{bmatrix} \quad \ldots\ldots\ldots (7)$$

where $\bar{X}_{ij} = \bar{X}_{ji} = \sum_{k=1}^{N} X_{ik} X_{jk}$

and $\bar{X}_i P = \sum_{k=1}^{N} X_{ik} P_k$

Hence the n+1 equations mentioned above can be written

$$\left[\begin{array}{c|c} 0 & \text{Transpose of } X_t \\ \hline X_t & X \end{array}\right] \left[\begin{array}{c} \lambda \\ \hline b \end{array}\right] = \left[\begin{array}{c} P_t \\ \hline P \end{array}\right] \quad \ldots\ldots\ldots (8)$$

The unknowns λ and b can be found by premultiplying each side of the equation by the inverse of the square symmetric matrix.

If the facilities in the regression program do not enable the Undetermined Multiplier to be used, the matrix equation solved will be

$$X\, b = P$$

In this case there is no guarantee that the component demands will sum to the known total demand, but as an expedient the resulting estimated components could be scaled so that they sum to the correct total, provided the adjustment is of little significance.

Yet another approach is to use a regression model with a constant term so that equation 1 becomes

$$\boxed{P_k = b_o + b_1 X_{1k} + b_2 X_{2k} + \ldots + b_n X_{nk} + e_k} \quad \ldots (9)$$

Provided the data for analysis cover the complete system, the component demands including the zero-component will automatically sum to the known system total demand with this approach. However, the zero-component, or constant term b_o, is a demand which for any half-hour is the same for all sub-areas and as such has no obvious physical interpretation. In consequence the use of a constant term is not recommended.

DETAILED INSTRUCTIONS FOR LOAD INVESTIGATION

1. Proceed to a Grid Station and collect demand data on radial feeders (ignore interconnected feeders and rings). For each month on the first-choice day listed at 3 collect 24 demand readings. If a serious power failure (very low or zero demands) is shown for any feeder, substitute the second choice day given in parenthesis for that feeder.

2. Give kWh advances wherever possible. 1/ Otherwise give current in amps. For amps only, give the voltage and an estimated power factor at the foot of each column. These should be typical values.

3. July 21 (23); August 19 (6); September 18 (17); October 20 (21); November 18 (19); December 15 (16); January 19 (22); February 21 (24); March 18 (24); April 16 (20); May 11 (23); June 9 (18). Second choice is in parenthesis.

4. Proceed to a local distribution office and collect the number of consumers and connected load (the latter is not required for residential) as shown at the head of the sheet.

5. Check every figure and make sure that any multipliers are given, for example kWh x 100.

1/ With the aid of hindsight, this was bad advice; current was the better practical measurement. In theory the square-law scales of the ammeters should have made them less accurate than the energy meters but the latter had serious resolution errors.

NAME OF SUB STATION ____________________

FEEDER ____________________

DATA COLLECTED BY ____________________

IS THE FEEDER RADIAL OR NOT? ____________________

ON THIS FEEDER - TOTAL

NUMBER OF RESIDENTIAL AND COMMERCIAL CONNECTION ____________________

CONNECTED LOAD IN K.W.-

SMALL INDUSTRIES (UNDER 70 K.W. EACH) __________ NOS. __________ K.W.
MEDIUM INDUSTRIES (70 UP TO 500 K.W. EACH) __________ NOS. __________ K.W.
LARGE INDUSTRIES __________ NOS. __________ K.W.

AGRICULTURE

TUBEWELLS, PUBLIC (SCARP OR IRRIGATION) __________ NOS. __________ K.W.
TUBEWELLS, PRIVATE ONLY __________ NOS. __________ K.W.

OTHER LOAD IN K.W. (IF IMPORTANT) __________ NOS. __________ K.W.
DESCRIBE OTHER LOAD __________ NOS. __________ K.W.

FEEDER DEMAND DATA

KWH ADVANCE (OR CURRENT IN AMPS)

HOUR	JULY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	
01.00													
02.00													
03.00													
04.00													
05.00													
19.00													
20.00													
21.00													
22.00													
23.00													
24.00													
POWER FACTOR													
VOLTAGE K.V.													

ESTIMATION OF COMPONENT LOAD CURVES FROM FEEDER DATA BY MULTIPLE-REGRESSION ANALYSIS

(1) Let Y_n = demand on nth feeder at a given hour

On nth feeder
(X_1 = No. of residential consumers
(X_2 = Connected load of small industries
(X_3 = Connected load of medium industries
(X_4 = Connected load of large industries
(X_5 = Connected load of public tubewells
(X_6 = Connected load of private tubewells

Then $Y_n = b_1X_1 + b_2X_2 + \ldots + b_6X_6 + \xi$

Given data for N feeders $1 \leqslant n \geqslant N$

find $b_1 \ldots b_6$ to minimise $\sum_{1}^{N} \xi_n^2$

(2) Repeat for each hour, separately for each **sample day of each month. That is for 12x24 = 288 times.**

(3) Multiply b_1 by the total X_1 for Northern Grid, i.e. total No. of residential consumers in that area, to give an estimate of residential demand for that hour. Repeat to generate load curves.

TABLE B-3 SHEET 1

FORECAST OF MONTHLY GENERATED ENERGY - NORTH GRID, SIND & KARACHI

(MILLIONS OF KWH)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1969-1970													
NORTH - TOTAL	340	352	355	360	337	356	366	339	375	335	365	379	4259
UPPER SIND - TOTAL	12	12	12	14	14	15	15	14	15	13	15	16	167
LOWER SIND - TOTAL	21	21	21	21	21	23	24	21	23	22	23	23	264
KARACHI - TOTAL	92	93	92	98	92	96	101	93	104	102	108	107	1178
TOTAL	465	478	480	493	464	490	506	467	517	472	511	525	5868
1970-1971													
NORTH - TOTAL	393	407	410	416	390	412	411	380	421	376	410	426	4852
UPPER SIND - TOTAL	15	15	15	17	18	18	19	17	19	16	18	19	206
LOWER SIND - TOTAL	25	24	25	24	24	27	28	24	26	26	26	27	306
KARACHI - TOTAL	110	112	111	118	111	116	116	107	120	117	125	123	1386
TOTAL	543	558	561	575	543	573	574	528	586	535	579	595	6750
1971-1972													
NORTH - TOTAL	441	458	461	468	438	463	458	424	469	419	457	475	5431
UPPER SIND - TOTAL	18	19	18	21	22	22	22	21	22	19	22	23	249
LOWER SIND - TOTAL	28	28	28	28	28	31	32	28	30	29	30	31	351
KARACHI - TOTAL	127	129	128	136	128	133	134	122	137	134	143	141	1592
TOTAL	614	634	635	653	616	649	646	595	658	601	652	670	7623
1972-1973													
NORTH - TOTAL	491	510	514	521	488	516	507	470	520	464	506	526	6033
UPPER SIND - TOTAL	21	22	22	25	26	27	26	24	26	22	26	26	293
LOWER SIND - TOTAL	32	32	32	32	32	35	37	32	35	34	35	36	404
KARACHI - TOTAL	146	148	146	156	146	153	153	140	157	154	163	161	1823
TOTAL	690	712	714	734	692	731	723	666	738	674	730	749	8553

TABLE 8-3

FORECAST OF MONTHLY GENERATED ENERGY - NORTH GRID, SIND & KARACHI

(MILLIONS OF KWH)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1973-1974													
NORTH - TOTAL	544	565	569	577	541	571	559	518	573	512	558	580	6667
UPPER SIND - TOTAL	25	26	25	29	30	31	30	28	30	25	30	30	339
LOWER SIND - TOTAL	37	36	37	36	36	40	42	36	40	39	40	41	460
KARACHI - TOTAL	167	169	167	179	167	175	172	157	176	173	184	182	2068
TOTAL	773	796	798	821	774	817	803	739	819	749	812	833	9534
1974-1975													
NORTH - TOTAL	600	623	627	636	596	630	609	564	625	558	608	632	7308
UPPER SIND - TOTAL	29	30	29	33	35	36	35	32	35	29	34	35	392
LOWER SIND - TOTAL	42	41	42	41	41	45	47	41	45	43	45	46	519
KARACHI - TOTAL	188	190	188	201	188	197	191	175	196	192	204	202	2312
TOTAL	859	884	886	911	860	908	882	812	901	822	891	915	10531
1975-1976													
NORTH - TOTAL	654	679	684	694	650	687	670	620	687	613	668	694	8000
UPPER SIND - TOTAL	33	35	34	39	40	42	40	36	40	33	39	40	451
LOWER SIND - TOTAL	47	46	47	46	46	51	53	46	50	49	50	51	582
KARACHI - TOTAL	208	211	209	223	209	219	212	194	217	213	227	224	2566
TOTAL	942	971	974	1002	945	999	975	896	994	908	984	1009	11599
1976-1977													
NORTH - TOTAL	719	746	752	762	714	755	735	681	754	673	734	762	8787
UPPER SIND - TOTAL	38	40	38	44	46	47	46	42	46	38	45	46	515
LOWER SIND - TOTAL	57	57	57	57	56	63	65	57	62	60	62	63	716
KARACHI - TOTAL	231	234	232	248	232	243	234	214	240	235	250	247	2840
TOTAL	1045	1077	1079	1111	1048	1108	1080	994	1102	1006	1091	1118	12859

TABLE 3-3 SHEET 3

FORECAST OF MONTHLY GENERATED ENERGY - NORTH GRID, SIND & KARACHI

(MILLIONS OF KWH)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1977-1978													
NORTH - TOTAL	789	819	825	837	784	828	804	745	825	736	803	834	9629
UPPER SIND - TOTAL	44	46	44	50	53	54	50	46	50	42	49	50	578
LOWER SIND - TOTAL	65	64	65	64	64	71	74	64	70	68	70	72	811
KARACHI - TOTAL	256	259	256	274	256	268	257	235	264	259	275	272	3131
TOTAL	1154	1188	1190	1225	1157	1221	1185	1090	1209	1105	1197	1228	14149
1978-1979													
NORTH - TOTAL	864	896	903	916	858	906	885	820	908	810	883	918	10567
UPPER SIND - TOTAL	48	50	48	55	58	60	52	48	52	44	51	52	618
LOWER SIND - TOTAL	75	74	75	74	73	81	85	73	80	78	80	82	930
KARACHI - TOTAL	281	284	282	301	282	295	282	258	289	283	301	298	3436
TOTAL	1268	1304	1308	1346	1271	1342	1304	1199	1329	1215	1315	1350	15551
1979-1980													
NORTH - TOTAL	950	986	994	1008	944	997	950	880	974	869	948	985	11485
UPPER SIND - TOTAL	50	52	50	58	60	62	60	55	60	50	58	60	675
LOWER SIND - TOTAL	79	78	79	78	77	86	90	78	85	82	85	87	984
KARACHI - TOTAL	308	311	309	329	309	323	307	281	315	309	328	324	3753
TOTAL	1387	1427	1432	1473	1390	1468	1407	1294	1434	1310	1419	1456	16897
1980-1981													
NORTH - TOTAL	1019	1058	1066	1081	1013	1070	1028	952	1054	941	1026	1066	12374
UPPER SIND - TOTAL	57	60	58	66	69	71	64	59	64	54	63	65	750
LOWER SIND - TOTAL	91	90	91	90	89	99	104	90	98	95	98	100	1135
KARACHI - TOTAL	335	339	336	359	336	351	333	305	342	335	356	352	4079
TOTAL	1502	1547	1551	1596	1507	1591	1529	1406	1558	1425	1543	1583	18238

TABLE B-3 SHEET 4

FORECAST OF MONTHLY GENERATED ENERGY - NORTH GRID, SIND & KARACHI

(MILLIONS OF KWH)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1981-1982													
NORTH - TOTAL	1103	1145	1153	1170	1096	1158	1110	1029	1139	1016	1108	1151	13378
UPPER SIND - TOTAL	61	64	62	71	74	76	68	63	68	57	66	69	799
LOWER SIND - TOTAL	99	98	99	98	97	108	113	98	107	104	107	109	1237
KARACHI - TOTAL	364	368	365	389	365	381	360	329	369	362	385	380	4417
TOTAL	1627	1675	1679	1728	1632	1723	1651	1519	1683	1539	1666	1709	19831
1982-1983													
NORTH - TOTAL	1192	1237	1246	1264	1185	1251	1193	1105	1224	1092	1191	1237	14417
UPPER SIND - TOTAL	65	68	66	75	79	81	72	67	72	61	71	73	850
LOWER SIND - TOTAL	108	107	108	107	106	118	123	107	117	113	117	119	1350
KARACHI - TOTAL	393	398	394	421	394	412	387	354	397	389	414	409	4762
TOTAL	1758	1810	1814	1867	1764	1862	1775	1633	1810	1655	1793	1838	21379
1983-1984													
NORTH - TOTAL	1281	1329	1339	1358	1273	1344	1272	1178	1305	1164	1269	1319	15431
UPPER SIND - TOTAL	69	72	70	80	84	87	77	71	77	64	75	77	903
LOWER SIND - TOTAL	117	115	117	115	114	127	133	115	126	122	126	128	1455
KARACHI - TOTAL	422	427	424	452	424	443	414	379	425	416	443	437	5106
TOTAL	1889	1943	1950	2005	1895	2001	1896	1743	1933	1766	1913	1961	22895
1984-1985													
NORTH - TOTAL	1366	1417	1428	1448	1357	1433	1347	1248	1382	1233	1344	1397	16400
UPPER SIND - TOTAL	73	77	74	85	89	92	80	74	80	67	78	81	950
LOWER SIND - TOTAL	124	123	124	123	121	135	141	122	134	129	134	136	1546
KARACHI - TOTAL	452	457	453	484	453	474	443	405	455	446	474	468	5464
TOTAL	2015	2074	2079	2140	2020	2134	2011	1849	2051	1875	2030	2082	24360

TABLE B-3

FORECAST OF MONTHLY GENERATED ENERGY - NORTH GRID, SIND & KARACHI

(MILLIONS OF KWH)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1985-86													
NORTH - TOTAL	1446	1501	1512	1534	1437	1518	1424	1319	1461	1303	1421	1477	17353
UPPER SIND - TOTAL	77	80	78	89	93	96	84	77	84	70	82	84	994
LOWER SIND - TOTAL	131	130	131	130	129	143	149	129	142	137	142	144	1637
KARACHI - TOTAL	484	490	485	518	485	507	474	434	486	477	507	501	5848
TOTAL	2138	2201	2206	2271	2144	2264	2131	1959	2173	1987	2152	2206	25832

TABLE B-4

FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH GRID, SIND & KARACHI

(MEGAWATTS)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1969-1970												
NORTH - TOTAL	761	790	822	807	781	799	819	840	840	775	817	878
UPPER SIND - TOTAL	26	28	28	31	33	33	35	35	35	30	34	36
LOWER SIND - TOTAL	48	47	49	47	48	52	54	52	51	51	51	54
KARACHI - TOTAL	205	208	213	220	213	215	227	230	233	236	242	248
TOTAL	1040	1073	1112	1105	1075	1099	1135	1157	1159	1092	1144	1216
1970-1971												
NORTH - TOTAL	879	912	950	933	903	923	920	944	944	870	918	986
UPPER SIND - TOTAL	33	35	35	38	41	41	42	43	42	37	41	44
LOWER SIND - TOTAL	55	54	57	54	56	60	62	60	59	59	59	62
KARACHI - TOTAL	248	251	256	265	256	259	261	264	268	271	279	285
TOTAL	1215	1252	1298	1290	1256	1283	1285	1311	1313	1237	1297	1377
1971-1972												
NORTH - TOTAL	988	1025	1067	1047	1014	1037	1025	1052	1052	970	1023	1099
UPPER SIND - TOTAL	40	42	42	47	50	50	50	51	50	44	49	52
LOWER SIND - TOTAL	63	63	65	63	64	69	72	69	68	68	68	72
KARACHI - TOTAL	285	288	295	305	295	299	299	303	307	311	320	327
TOTAL	1376	1418	1469	1462	1423	1455	1446	1475	1477	1393	1460	1550
1972-1973												
NORTH - TOTAL	1101	1142	1189	1167	1130	1155	1136	1165	1165	1074	1133	1217
UPPER SIND - TOTAL	48	50	50	56	60	60	59	60	59	51	57	61
LOWER SIND - TOTAL	73	72	75	72	73	79	82	79	78	78	78	82
KARACHI - TOTAL	327	331	339	350	339	343	342	347	351	356	366	374
TOTAL	1549	1595	1653	1645	1602	1637	1619	1651	1653	1559	1634	1734

TABLE B-4

FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH GRID, SIND & KARACHI

(MEGAWATTS)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1973-1974												
NORTH - TOTAL	1219	1265	1317	1293	1252	1280	1252	1284	1284	1184	1250	1342
UPPER SIND - TOTAL	56	59	59	65	70	70	68	69	68	59	66	71
LOWER SIND - TOTAL	83	82	86	82	84	90	94	90	89	89	89	94
KARACHI - TOTAL	374	378	387	400	387	392	385	390	395	400	412	420
TOTAL	1732	1784	1849	1840	1793	1832	1799	1833	1836	1732	1817	1927
1974-1975												
NORTH - TOTAL	1344	1395	1452	1426	1380	1411	1365	1400	1400	1291	1362	1462
UPPER SIND - TOTAL	65	68	68	75	81	81	78	80	78	68	77	82
LOWER SIND - TOTAL	93	92	96	92	94	102	106	102	101	101	101	106
KARACHI - TOTAL	420	425	436	450	436	441	428	433	439	445	457	467
TOTAL	1922	1980	2052	2043	1991	2035	1977	2015	2018	1905	1997	2117
1975-1976												
NORTH - TOTAL	1465	1520	1583	1554	1505	1538	1500	1539	1539	1419	1497	1607
UPPER SIND - TOTAL	75	78	78	87	94	94	89	90	89	77	87	92
LOWER SIND - TOTAL	104	103	108	103	106	114	119	114	113	113	113	119
KARACHI - TOTAL	467	473	484	500	484	490	475	481	487	493	508	518
TOTAL	2111	2174	2253	2244	2189	2236	2183	2224	2228	2102	2205	2336
1976-1977												
NORTH - TOTAL	1611	1671	1740	1708	1654	1690	1647	1689	1689	1557	1643	1764
UPPER SIND - TOTAL	85	89	89	98	106	106	102	104	102	89	100	106
LOWER SIND - TOTAL	129	127	133	127	130	140	146	140	139	139	139	146
KARACHI - TOTAL	518	525	537	555	537	543	524	531	538	545	561	573
TOTAL	2343	2412	2499	2488	2427	2479	2419	2464	2468	2330	2443	2589

TABLE B-4

FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH GRID, SIND & KARACHI

(MEGAWATTS)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1977-1978												
NORTH - TOTAL	1768	1835	1910	1875	1815	1856	1802	1848	1848	1704	1798	1931
UPPER SIND - TOTAL	98	102	102	113	122	122	112	114	112	97	110	117
LOWER SIND - TOTAL	146	144	151	144	148	159	166	159	158	158	158	166
KARACHI - TOTAL	573	579	593	613	593	600	576	584	592	599	617	630
TOTAL	2585	2660	2756	2745	2678	2737	2656	2705	2710	2558	2683	2844
1978-1979												
NORTH - TOTAL	1935	2007	2090	2052	1986	2031	1983	2034	2034	1875	1979	2125
UPPER SIND - TOTAL	107	112	112	124	134	134	116	119	116	101	114	121
LOWER SIND - TOTAL	167	165	173	165	169	182	190	182	180	180	180	190
KARACHI - TOTAL	630	637	652	674	652	660	631	640	648	656	675	689
TOTAL	2839	2921	3027	3015	2941	3007	2920	2975	2978	2812	2948	3125
1979-1980												
NORTH - TOTAL	2129	2209	2300	2258	2186	2235	2127	2182	2182	2012	2123	2279
UPPER SIND - TOTAL	111	116	116	129	139	139	133	136	133	116	130	139
LOWER SIND - TOTAL	177	175	183	175	179	193	201	193	191	191	191	201
KARACHI - TOTAL	689	698	714	738	714	723	688	697	706	715	735	751
TOTAL	3106	3198	3313	3300	3218	3290	3149	3208	3212	3034	3179	3370
1980-1981												
NORTH - TOTAL	2284	2370	2467	2422	2345	2397	2302	2361	2361	2177	2297	2467
UPPER SIND - TOTAL	128	133	133	148	159	159	143	146	143	125	140	149
LOWER SIND - TOTAL	204	202	211	202	206	223	232	223	220	220	220	232
KARACHI - TOTAL	751	760	778	804	778	787	746	756	765	775	798	815
TOTAL	3367	3465	3589	3576	3488	3566	3423	3486	3489	3297	3455	3663

TABLE B-4 SHEET 4

FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH GRID, SIND & KARACHI

(MEGAWATTS)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1981-1982												
NORTH - TOTAL	2471	2565	2670	2621	2538	2594	2488	2551	2551	2353	2482	2665
UPPER SIND - TOTAL	137	143	143	159	171	171	152	155	152	132	149	159
LOWER SIND - TOTAL	223	220	230	220	225	243	253	243	240	240	240	253
KARACHI - TOTAL	815	824	844	872	844	854	806	816	827	838	862	880
TOTAL	3646	3752	3887	3872	3778	3862	3699	3765	3770	3563	3733	3957
1982-1983												
NORTH - TOTAL	2670	2771	2885	2832	2742	2803	2673	2741	2741	2528	2667	2864
UPPER SIND - TOTAL	146	152	152	169	182	182	162	165	162	141	159	169
LOWER SIND - TOTAL	242	240	251	240	245	264	275	264	262	262	262	275
KARACHI - TOTAL	880	891	912	942	912	922	866	878	889	901	927	946
TOTAL	3938	4054	4200	4183	4081	4171	3976	4049	4054	3832	4015	4254
1983-1984												
NORTH - TOTAL	2869	2978	3100	3043	2946	3012	2850	2923	2923	2695	2844	3053
UPPER SIND - TOTAL	155	162	162	180	194	194	171	175	171	149	168	179
LOWER SIND - TOTAL	261	258	270	258	264	285	297	285	282	282	282	297
KARACHI - TOTAL	946	958	980	1013	980	992	927	939	952	964	992	1013
TOTAL	4231	4356	4512	4494	4384	4483	4245	4322	4328	4090	4286	4542
1984-1985												
NORTH - TOTAL	3059	3174	3305	3244	3141	3211	3018	3095	3095	2854	3011	3233
UPPER SIND - TOTAL	164	171	171	190	205	205	179	183	179	156	176	187
LOWER SIND - TOTAL	278	275	287	275	281	303	316	303	300	300	300	316
KARACHI - TOTAL	1013	1025	1049 ✓	1084	1049	1061	992	1005	1018	1031	1061	1084
TOTAL	4514	4645	4812	4793	4676	4780	4505	4586	4592	4341	4548	4820

TABLE B-4 SHEET 5

FORECAST OF MONTHLY GENERATOR PEAK LOADS - NORTH GRID, SIND & KARACHI

(MEGAWATTS)

1985-1986	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
NORTH - TOTAL	3240	3362	3500	3436	3326	3400	3190	3272	3272	3017	3184	3418
UPPER SIND - TOTAL	172	179	179	199	215	215	187	191	187	163	183	195
LOWER SIND - TOTAL	294	291	304	291	298	321	334	321	318	318	318	334
KARACHI - TOTAL	1084	1097	1123	1160	1123	1136	1061	1075	1089	1103	1135	1159
TOTAL	4790	4929	5106	5086	4962	5072	4772	4859	4866	4601	4820	5106

TABLE G-4 SHEET 1

NORTHERN GRID

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(INCLUDING SCHEDULED MAINTENANCE)

1969 - 1970 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	130(4)	130(4)	130(4)	130(4)	190(4)	190(4)	190(4)	190(4)	190(4)	190(4)	190(4)	190(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	28(4)	28(4)	28(4)	42(4)	42(4)	56(6)	55(5)	56(6)	56(6)	56(6)	56(6)	42(5)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	280(4)	280(4)	280(4)	280(4)	280(4)	280(4)	280(4)	320(4)	232(4)	232(4)	320(4)	320(4)
A TOTAL CAPABILITY	818	818	818	772	800	806	805	846	782	850	946	932
*B FIRM CAPABILITY	718	718	718	672	700	706	705	762	716	784	866	835
**C PEAK LOAD	761	790	822	807	781	799	819	840	840	775	817	878
SURPLUS GEN.(A-C)	57	28	-4	-35	19	7	-13	6	-58	75	129	54
FIRM SURPLUS GEN.(B-C)	-43	-72	-104	-135	-81	-93	-113	-78	-124	9	49	-43
***PUBLIC TUBEWELLS	79	84	107	107	90	72	99	130	130	68	90	130

* FIRM CAPABILITY=TOTAL CAPABILITY MINUS LARGEST UNIT

** INCLUDES PUBLIC TUBEWELLS THAT ARE AT PRESENT SHUT OFF DAILY FOR TWO HOURS DURING PEAK LOAD PERIODS

*** ABOUT 60% OF PUBLIC TUBEWELL LOADS ARE SHED DURING PEAK HOURS;SURPLUS GENERATION CAN BE MODIFIED ACCORDINGLY

N - NORTH ZONE;S - SOUTH ZONE

TABLE C-4

SHEET 2

NORTHERN GRID

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1970 - 1971 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	320(4)	320(4)	320(4)	460(4)	460(4)	452(4)	400(4)	336(4)	232(4)	232(4)	320(4)	485(5)
A TOTAL CAPABILITY	1042	1042	1042	1122	1090	1074	1022	958	878	946	1042	1207
*B FIRM CAPABILITY	942	942	942	1007	975	961	922	874	812	880	962	1110
**C PEAK LOAD	879	912	950	933	903	923	920	944	944	870	918	986
SURPLUS GEN.(A-C)	163	130	92	189	187	151	102	14	-66	76	124	221
FIRM SURPLUS GEN.(B-C)	63	30	-8	74	72	38	2	-70	-132	10	44	124
***PUBLIC TUBEWELLS	108	116	146	146	124	99	132	173	173	91	120	173

SEE FOOT NOTES ON SHEET 1

TABLE C-4 SHEET 3

NORTHERN GRID

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1971 - 1972 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(5)	82(6)	82(6)	82(6)	82(6)	82(6)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	575(5)	690(6)	690(6)	690(5)	590(5)	578(6)	600(5)	504(6)	348(6)	348(6)	480(6)	582(5)
S - GUDU	0	0	0	0	0	0	0	0	60(1)	60(1)	100(2)	100(2)
A TOTAL CAPABILITY	1297	1412	1412	1352	1320	1300	1222	1126	1054	1122	1302	1404
*B FIRM CAPABILITY	1182	1297	1297	1237	1205	1187	1122	1042	988	1056	1202	1304
**C PEAK LOAD	988	1025	1067	1047	1014	1037	1025	1052	1052	970	1023	1099
SURPLUS GEN. (A-C)	309	387	345	305	306	263	197	74	2	152	279	305
FIRM SURPLUS GEN. (B-C)	194	272	230	190	191	150	97	-10	-64	86	179	205
***PUBLIC TUBEWELLS	144	154	195	195	165	132	138	181	181	95	125	181

SEE FOOT NOTES ON SHEET 1

TABLE C-4

NORTHERN GRID

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1972 - 1973 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	575(6)	690(6)	690(6)	690(6)	690(6)	678(6)	500(5)	504(6)	348(6)	348(6)	480(6)	582(5)
S - GUDU	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)	100(2)
A TOTAL CAPABILITY	1397	1512	1512	1452	1420	1400	1222	1226	1094	1162	1302	1404
*B FIRM CAPABILITY	1282	1397	1397	1337	1305	1287	1122	1126	994	1062	1202	1304
**C PEAK LOAD	1101	1142	1189	1167	1130	1155	1136	1165	1165	1074	1133	1217
SURPLUS GEN. (A-C)	296	370	323	285	290	245	85	61	-71	88	169	187
FIRM SURPLUS GEN. (B-C)	181	255	208	170	175	132	-14	-39	-171	-12	69	87
***PUBLIC TUBEWELLS	151	163	204	204	172	138	138	181	181	95	125	181

SEE FOOT NOTES ON SHEET 1

TABLE C-4

NORTHERN GRID & UPPER SIND

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1973 - 1974 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	55(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	690(6)	690(6)	690(6)	690(6)	805(7)	791(7)	700(7)	588(7)	464(8)	464(8)	640(8)	776(8)
S - GUDU	100(2)	100(2)	100(2)	100(2)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)
S - SUKKUR	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)
A TOTAL CAPABILITY	1562	1562	1562	1502	1905	1883	1792	1680	1580	1648	1832	1968
*B FIRM CAPABILITY	1447	1447	1447	1387	1705	1683	1592	1480	1380	1448	1632	1768
**C PEAK LOAD	1275	1324	1376	1358	1322	1350	1320	1353	1352	1243	1316	1413
SURPLUS GEN.(A-C)	287	238	186	144	583	533	472	327	228	405	515	555
FIRM SURPLUS GEN.(B-C)	172	123	71	29	383	333	272	127	28	205	316	355
***PUBLIC TUBEWELLS	151	161	204	204	172	138	138	181	181	95	125	181

SEE FOOT NOTES ON SHEET 1

TABLE C-4 SHEET 5

NORTHERN GRID & UPPER SIND

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1974 - 1975 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(5)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	55(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	920(8)	920(8)	920(8)	920(8)	920(8)	904(8)	800(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	0	0	0	0	0	0	0	0	0	0	0	232(2)
S - GUDU	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)
S - SUKKUR	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)
A TOTAL CAPABILITY	2112	2112	2112	2052	2020	1996	1892	1764	1580	1649	1832	2200
*B FIRM CAPABILITY	1912	1912	1912	1852	1820	1796	1692	1564	1380	1448	1632	2000
**C PEAK LOAD	1409	1463	1520	1501	1451	1492	1438	1475	1473	1355	1434	1538
SURPLUS GEN. (A-C)	703	649	592	551	559	504	454	289	107	293	398	662
FIRM SURPLUS GEN. (B-C)	503	449	392	351	359	304	254	89	-93	93	198	462
***PUBLIC TUBEWELLS	151	161	204	204	172	138	138	181	181	95	125	181

SEE FOOT NOTES ON SHEET 1

TABLE C-4 SHEET 7

NORTHERN GRID & UPPER SIND

GENERATING CAPABILITY VERSUS DEMAND (MW) (PRELIMINARY)

(AVERAGE WATER YEAR)

(EXCLUDING SCHEDULED MAINTENANCE)

1975 - 1976 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)	260(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)	82(6)
N - WARSAK	160(4)	160(4)	160(4)	100(4)	100(4)	100(4)	100(4)	100(4)	100(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	55(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	920(8)	920(8)	920(8)	920(8)	920(8) (?)	904(8)	800(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	346(2)	404(2)	404(2)	404(2)	384(2)	364(2)	336(2)	294(2)	230(2)	158(2)	146(2)	232(2)
S - GUDU	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)
S - SUKKUR	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)	50(4)
A TOTAL CAPABILITY	2458	2516	2516	2456	2404	2360	2228	2058	1810	1806	1978	2200
*B FIRM CAPABILITY	2258	2316	2316	2256	2204	2160	2028	1858	1610	1606	1778	2000
**C PEAK LOAD	1535	1593	1656	1635	1593	1626	1583	1624	1622	1491	1578	1693
SURPLUS GEN. (A-C)	923	923	860	821	811	734	645	434	188	315	400	507
FIRM SURPLUS GEN. (B-C)	723	722	660	621	611	534	445	234	-12	115	200	307
***PUBLIC TUBEWELLS	151	161	204	204	172	138	138	181	181	95	125	181

SEE FOOT NOTES ON SHEET 1

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1975 - 1976 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	695(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	346(2)	404(2)	404(2)	404(2)	384(2)	318(2)	294(2)	258(2)	230(2)	316(4)	292(4)	464(4)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	3145	3291	3323	3251	3007	2901	2781	2721	2509	2643	2803	3111
B FIRM CAPABILITY*	2772	2889	2921	2849	2615	2542	2434	2392	2194	2364	2530	2795
C PEAK LOAD	2111	2174	2253	2244	2189	2236	2183	2224	2228	2102	2205	2336
A MINUS C	1034	1117	1070	1007	818	665	598	497	281	541	598	775
B MINUS C	661	715	668	605	426	306	251	168	-34	262	325	459

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1976 - 1977 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	692(4)	808(4)	808(4)	808(4)	768(4)	636(4)	588(4)	516(4)	690(6)	474(6)	438(6)	696(5)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	3491	3695	3727	3655	3391	3219	3075	2979	2969	2801	2949	3343
B FIRM CAPABILITY*	3118	3293	3325	3253	2999	2860	2728	2650	2654	2522	2676	3027
C PEAK LOAD	2343	2412	2499	2488	2427	2479	2419	2464	2468	2330	2443	2589
A MINUS C	1148	1283	1228	1167	964	740	656	515	501	471	506	754
B MINUS C	775	881	826	765	572	381	309	186	186	192	233	438

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1977 - 1978 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(5)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	695(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	1038(6)	1212(6)	1212(6)	1212(6)	1152(6)	954(6)	882(6)	774(6)	690(6)	474(6)	438(6)	696(5)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	420(3)	620(4)	620(4)	620(4)	620(4)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	3837	4099	4131	4059	3775	3537	3369	3237	3169	3001	3149	3543
B FIRM CAPABILITY*	3464	3697	3729	3657	3383	3178	3022	2908	2854	2722	2876	3227
C PEAK LOAD	2585	2660	2756	2745	2678	2737	2656	2705	2710	2558	2683	2844
A MINUS C	1252	1439	1375	1314	1097	800	713	532	459	443	466	699
B MINUS C	879	1037	973	912	705	441	366	203	144	164	193	383

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1978 - 1979 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(5)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	1038(6)	1212(6)	1212(6)	1212(6)	1152(6)	954(6)	882(6)	774(6)	920(8)	632(8)	584(8)	928(8)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	4037	4299	4331	4259	3975	3737	3569	3437	3399	3159	3295	3775
B FIRM CAPABILITY*	3664	3897	3929	3857	3583	3378	3222	3108	3084	2880	3022	3459
C PEAK LOAD	2839	2921	3027	3015	2941	3007	2920	2975	2978	2812	2948	3125
A MINUS C	1198	1378	1304	1244	1034	730	649	462	421	347	347	650
B MINUS C	825	976	902	842	642	371	302	133	106	68	74	334

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1979 - 1980 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	1384(8)	1616(8)	1616(8)	1616(8)	1536(8)	1272(8)	1176(8)	1032(8)	1150(10)	790(10)	730(10)	1150(10)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	620(4)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	4383	4703	4735	4663	4359	4055	3863	3695	3829	3517	3641	4207
B FIRM CAPABILITY*	4010	4301	4333	4261	3967	3696	3516	3366	3514	3238	3368	3891
C PEAK LOAD	3106	3198	3313	3300	3218	3290	3149	3208	3212	3034	3179	3370
A MINUS C	1277	1505	1422	1363	1141	765	714	487	617	483	462	837
B MINUS C	904	1103	1020	961	749	406	367	158	302	204	189	521

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1980 - 1981 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	595(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	1730(10)	2020(10)	2020(10)	2020(10)	1920(10)	1590(10)	1470(10)	1290(10)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	0	0	0	0	0	0	0	0	250(1)	250(1)	250(1)	250(1)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	4929	5307	5339	5267	4943	4573	4357	4153	4309	3925	4037	4689
B FIRM CAPABILITY*	4556	4905	4937	4865	4551	4214	4010	3824	3859	3475	3587	4239
C PEAK LOAD	3367	3465	3589	3576	3488	3566	3423	3486	3489	3297	3455	3563
A MINUS C	1562	1842	1750	1691	1455	1007	934	667	820	628	582	1026
B MINUS C	1189	1440	1348	1289	1063	648	587	338	370	178	132	576

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1981 - 1982 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(5)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	2076(12)	2424(12)	2424(12)	2424(12)	2304(12)	1908(12)	1764(12)	1548(12)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	250(1)	250(1)	250(1)	250(1)	250(1)	250(1)	250(1)	250(1)	500(2)	500(2)	500(2)	500(2)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	5525	5961	5993	5921	5577	5141	4901	4661	4559	4175	4287	4939
B FIRM CAPABILITY*	5075	5511	5543	5471	5127	4691	4451	4211	4109	3725	3837	4489
C PEAK LOAD	3646	3752	3887	3872	3778	3862	3699	3765	3770	3563	3733	3957
A MINUS C	1879	2209	2106	2049	1799	1279	1202	896	789	612	554	982
B MINUS C	1429	1759	1656	1599	1349	829	752	446	339	162	104	532

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1982 - 1983 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	695(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	2076(12)	2424(12)	2424(12)	2424(12)	2304(12)	1908(12)	1764(12)	1548(12)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	500(2)	500(2)	500(2)	500(2)	500(2)	500(2)	500(2)	500(2)	750(3)	750(3)	750(3)	750(3)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	5775	6211	6243	6171	5827	5391	5151	4911	4809	4625	4537	5189
B FIRM CAPABILITY*	5325	5761	5793	5721	5377	4941	4701	4461	4359	3975	4087	4739
C PEAK LOAD	3938	4054	4200	4183	4081	4171	3976	4049	4054	3832	4015	4254
A MINUS C	1837	2157	2043	1988	1746	1220	1175	862	755	593	522	935
B MINUS C	1387	1707	1593	1538	1296	770	725	412	305	143	72	485

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1983 - 1984 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(5)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	2076(12)	2424(12)	2424(12)	2424(12)	2304(12)	1908(12)	1764(12)	1548(12)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	750(3)	750(3)	750(3)	750(3)	750(3)	750(3)	750(3)	750(3)	1000(4)	1000(4)	1000(4)	1000(4)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	6025	6461	6493	6421	6077	5641	5401	5161	5059	4675	4787	5439
B FIRM CAPABILITY*	5575	6011	6043	5971	5627	5191	4951	4711	4609	4225	4337	4989
C PEAK LOAD	4231	4356	4512	4494	4384	4483	4245	4322	4328	4090	4286	4542
A MINUS C	1794	2105	1981	1927	1693	1158	1156	839	731	585	501	897
B MINUS C	1344	1655	1531	1477	1243	708	706	389	281	135	51	447

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1984 - 1985 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(5)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	696(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	2076(12)	2424(12)	2424(12)	2424(12)	2304(12)	1908(12)	1764(12)	1548(12)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	1000(4)	1000(4)	1000(4)	1000(4)	1000(4)	1000(4)	1000(4)	1000(4)	1500(6)	1500(6)	1500(6)	1500(6)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	6275	6711	6743	6671	6327	5891	5651	5411	5559	5175	5287	5939
B FIRM CAPABILITY*	5825	6261	6293	6221	5877	5441	5201	4961	5109	4725	4837	5489
C PEAK LOAD	4514	4645	4812	4793	4676	4780	4505	4586	4592	4341	4548	4820
A MINUS C	1761	2066	1931	1878	1651	1111	1146	825	967	834	739	1119
B MINUS C	1311	1616	1481	1428	1201	661	696	375	517	384	289	669

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TABLE C-5 SHEET 11

WEST PAKISTAN GRID

GENERATION CAPABILITY VERSUS DEMAND (MW)

(AVERAGE WATER YEAR)

1985 - 1986 MONTHLY PLANT CAPABILITY - MEGAWATTS (NO. OF UNITS INSTALLED)

ZONE - PLANT	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
N - MULTAN	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)	240(4)
N - LYALLPUR	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
N - SHAHDARA	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)	84(6)
N - WARSAK	160(4)	160(4)	160(4)	120(4)	120(4)	120(4)	120(4)	120(4)	120(4)	160(4)	160(4)	160(4)
N - HYDELS	88(8)	88(8)	88(8)	88(8)	56(8)	48(8)	48(8)	48(8)	72(8)	80(8)	88(8)	88(8)
N - MANGLA	928(8)	1016(8)	1048(8)	1016(8)	824(8)	792(8)	695(8)	672(8)	464(8)	464(8)	640(8)	776(8)
N - TARBELA	2076(12)	2424(12)	2424(12)	2424(12)	2304(12)	1908(12)	1764(12)	1548(12)	1380(12)	948(12)	876(12)	1392(12)
N - KALABAGH	1500(6)	1500(6)	1500(6)	1500(6)	1500(6)	1500(6)	1500(6)	1500(6)	1750(7)	1750(7)	1750(7)	1750(7)
S - HYDERABAD	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)	43(5)
S - KOTRI	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)	42(3)
S - GUDU	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)	820(5)
S - SUKKUR	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)	52(4)
K - KARACHI(B)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)	30(2)
K - KARACHI(BX)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)	60(2)
K - KORANGI(1&2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)	132(2)
K - KORANGI(3)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KARACHI(NUC)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)	125(1)
K - KORANGI(4)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)	138(1)
A TOTAL CAPABILITY	6775	7211	7243	7171	6827	6391	6151	5911	5809	5425	5537	6189
B FIRM CAPABILITY*	6325	6761	6793	6721	6377	5941	5701	5461	5359	4975	5087	5739
C PEAK LOAD	4790	4929	5106	5086	4962	5072	4772	4859	4866	4601	4820	5106
A MINUS C	1985	2282	2137	2085	1865	1319	1379	1052	943	824	717	1083
B MINUS C	1535	1832	1687	1635	1415	869	929	602	493	374	267	633

* FIRM CAPABILITY IS TOTAL CAPABILITY MINUS SUM OF CAPABILITIES OF LARGEST HYDRO AND LARGEST THERMAL UNITS.

TUBEWELL DEMANDS

Projection of Power Demand of Private Tubewells (Mid-1970 - Mid-1990)

1. The projection of the number of private electrified tubewells is influenced *inter alia* by Government policies concerning, e.g., credit, electrical power situation, diesel fuel availability, public tubewell development, etc., which are in themselves difficult to project. An attempt has been made to extend the projected growth of private tubewells from 1970 up to mid-1990, based on the estimates in the June 1970 Indus Basin Review Mission Report. The growth rate has been assumed to decline by 10% during each five-year period starting from a growth of 43% for the period 1970-75 projected by the review mission under the assumption of the slower growth of public tubewells. In order to check the reasonableness of these forecasts, the area presently served by private tubewells was compared with the usable ground water area which can still be tapped by private tubewells. The Indus Basin Review Mission estimates that about 28% of the usable ground water area is presently used. Thus, the number of tubewells could triple. The estimates made here reach this mark approximately by 1990. Stone & Webster (1965) projected a similar trend.

2. It is also assumed that:

a. Average monthly demand per private tubewell remains the same throughout the projected period (Table 1).

Table 1

Estimated Average Demand
Per Consumer for Private Tubewells
(Hrs. 1630-2100)

kW

Jan.	Feb.	Mar.	Apr.	May	June	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1.3	0.4	2.6	1.3	1.3	5.4	5.8	6.7	5.4	4	1.6	1.4

b. The percentage of tubewells electrified will rise from 45% in June 1970 to 50% by mid-1975 and that this percentage remains constant at 50% to 1990 (Table 2).

Table 2

Number of Private Tubewells
Used in Projections of Power Requirements

	Total	Growth	Electrified	% of Total
mid-1970	81,000)		36,500	45
1971	88,200)		40,600	46
1972	95,400)		45,000	47
1973	102,600)	43%	50,000	48
1974	110,000)		53,900	49
1975	116,000)		58,000	50
	)	33%		
1980	154,000)		77,000	50
1985	189,000)	23%	94,000	50
1990	214,000)	13%	107,000	50

c. The Northern Region (Lahore and Peshawar regions) accounted in 1969 for 95% of West Pakistan's total number of private tubewells. This preponderance of the Northern Region has been assumed to last until the end of the projected period.

d. The present average capacity of private tubewells in West Pakistan of 1.2 cusec is assumed to remain constant.

Projection of Power Demand for Public Tubewells in West Pakistan (Mid-1970 - Mid-1975)

3. The basis for the projections is the recent Indus Basin Review Mission Report (June 1970). There the present and projected number of electrified public tubewells can be found. These data are reproduced in Table 3. In order to come up with an estimate of the monthly number of tubewells the additional tubewells (1970-75) were divided by 60 and the then monthly additions added progressively. The lower of the two postulated growth patterns was used.

4. The hourly and monthly power demand patterns were taken from data developed for Chapter 4. Various other sources on tubewells gave no better alternative. Since the seasonal demand patterns for Chapter 4 were given in terms of proportions of installed loads, the installed load itself has to be estimated. Various data suggest a rough average installed load of 20 kW per tubewell. A PIDE Study (January 1966) on SCARP I tubewells indicates that the average measured load was 21 kW. In another effort to find a representative installed load, the following calculation was performed:

Table 3

Estimated Seasonal Pumping from Private Tubewells and Persian Wheels 1974-75

(MAF)

Year	Source	Kharif	Rabi	Year
1969/70	Private Tubewells	6.4	7.0	13.4
	Persian Wheels	0.3	1.0	1.3
	Total	6.7	8.0	14.7
1974/75 (3,000 additional public tubewells case)	Private Tubewells - canal commanded and public tubewell areas	5.4	8.1	13.5
	Private Tubewells - uncommanded areas	3.0	2.7	5.7
	Sub-total Private Tubewells	8.4	10.8	19.2
	Persian Wheels	0.2	0.7	0.9
	Total	8.6	11.5	20.1
1974/75 (7,000 additional public tubewells case)	Private Tubewells - canal commanded and public tubewell areas	4.7	7.2	11.9
	Private Tubewells - uncommanded areas	2.9	2.6	5.5
	Sub-total Private Tubewells	7.6	9.8	17.4
	Persian Wheels	0.1	0.6	0.7
	Total	7.7	10.4	18.1

Source: Sir Alexander Gibb & Partners and Associates, Indus Basin Review Mission Report - June 1970.

5. The Indus Basin Review Mission Report indicates that, in 1970, public tubewells consumed 387 million kWh. Dividing this total consumption by the number of tubewells, we get a per tubewell figure. Dividing again the per tubewell consumption by an estimate of annual consumption per kW, we get an installed load of 25 kW. This figure was used in the projections.

6. The projections take into consideration 25% system losses (generating plus transmission losses), the loads were averaged for the hours 16:30-21:00, the monthly pattern and the installed load have been assumed to remain constant (Table 4).

Table 4

Monthly kW Factors per Public Tubewell used in Projections
(Hrs. 16:30-21:00)

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
8.8	8.0	6.0	9.5	10.3	1.1	14.3	10.0	11.0	9.3	5.5	3.3

7. In contrast to our projected private tubewell pattern, our public tubewell pattern shows less overall dispersion. Comparing it with the Harza forecasts (1970-71) it can be noticed that the pattern is similar, but differs during the months of November, December and March. Whereas our forecasts assume a fixed seasonal pattern, Harza's forecasts show from 1972-73 a flattening out of the seasonal curve.

NO-METER METHODS OF CHARGING FOR

ELECTRICITY SUPPLIED TO SMALL USERS

1. First a reminder that the zero-incremental price of energy with no-meter charging is thought objectionable, see Chapter 2, except insofar as the technical possibilities of using or wasting energy are small. Instead of an energy meter some demand-restrictive device can be used to prevent abuse of the "free" supply. This kind of tariff should not be confused with the two-part tariff in which an energy meter is backed up by a demand-restrictive device where the latter forms the basis, of the fixed charge (for example, the residential rates of Electricite de France). Such confusion is engendered by the practice (of Tokyo and Djakarta) of having some critical demand at which the no-meter rate is replaced by the meter plus demand-restriction rate. Evidently the absence of a meter is thought acceptable only for the smallest installations, though these may, of course, be numerous.

2. In Djakarta up to 200 watts is supplied without a meter and in Tokyo up to 400. The bill is based upon either:

a. the setting, or nominal limit, of the demand-restrictive device, or

b. the connected load of the installation obtained by inspection. 1/

It is not clear what relative impacts items a. and b. have in practice. Very likely the consumer declares, say, 200 watts of lighting and a device is installed which in fact restricts him to about 250 watts but which has a nominal setting of 200 watts.

3. A fuse 2/ can be used to limit supply but is an exceedingly coarse device of uncertain calibration. Also when blown it requires a visit by a serviceman to restore supply. In contrast the various kinds of load limiter or circuit breaker can easily be reset by the consumer pushing a button once he has sufficiently reduced his demand. In one case, 1.2 times the current setting is permitted to flow indefinitely, whereas twice the setting is cut off after 10 seconds. The settings used in France (with meters) are 5, 10 and 15 A or higher values, and in Djakarta (without meters) are 100 to 200 watts in steps of 25.

1/ Inspection of the installation seems to play a part and in Tokyo the lamp bulbs for use on this rate are loaned to the consumer who pays 3 US cents for a replacement on production of the faulty bulb.

2/ That is simple low-cost copper-wire fuses. Cleverly-designed silver-wire fuses are available at a greatly enhanced price.

4. The Djakarta supply authority pays US$3 per load limiter to substitute for a single-phase meter priced at, say, US$8 for a cheap version. The saving on the metering itself is therefore around US¢4 per month per small consumer. It follows that other cost items need to be carefully evaluated before it can be said whether or not a load limiter enables the metering and revenue collection costs to be reduced for the small user.

5. Load limiters (disjoncteurs) are a long-standing feature of French residential tariffs. They are of radically different construction from those used in Djakarta and incorporate earth-leakage protection of the consumer's installation. Also, they are used only with energy meters. In consequence of these and other important differences, such as a price of US$10, the widespread use of these devices in France cannot be put forward in support of any proposal to omit energy meters for small users.

ANNEX 10

CONTROLLED FREQUENCY FOR TIMEKEEPING

1. Synchronous timeswitches with spring-reserve are likely to give better service than those which rely completely on escapements. It is, therefore, in the interests of WAPDA to control system frequency so that such timeswitches, if installed, would keep time.

2. Granted fairly frequent power failures, though not usually of long duration, the frequency should be controlled so that the following quantity averages to zero:

Drift	=	(Lapsed synchronous time)
	+	(Time power off)
	-	(Pendulum time)

If drift is positive reduce frequency: if negative increase.

3. A spring-reserve, synchronous timeswitch (unless any breakdown exceeds the reserve time of up to 30 hours) automatically indicates the sum of lapsed synchronous time and time power off. It therefore follows that a centrally placed spring-reserve, synchronous timeswitch would conveniently indicate the need to increase or reduce system frequency by comparison with a pendulum clock.

4. If this were done, similar timeswitches throughout the system could be said to be keeping time. The varying incidence of power failures throughout the system should be of little consequence provided the availability of supply more or less everywhere exceeds 90%. Experiments with frequency control for this purpose are recommended since many problems in metering, apart from temporal pricing, can be readily and inexpensively solved with the aid of controlled frequency but not without.

PRICING OF MAGNETIZING CURRENT

1. The total electric current flowing in a circuit supplying electric motors or transformers (and perhaps other devices) fulfills two purposes useful to the consumer. One, it provides heat or work proportional to the kWh consumed, called the energy, and secondly it provides a magnetic field essential to the working of motors and transformers. The second function is normally provided free of charge as a by-product of the energy taken provided that usage is secondary.

2. If the secondary usage is substantial the consumer is said to have a low power factor and a penalty is applied on the WAPDA system by increasing the maximum demand charge by 1% for each percentage point the power factor falls below 85%. The metering for this penalty consists of a second meter (called the reactive energy meter) indicating a quantity symbolized as KVArh. From the ratio of the monthly advance in KVArh to the monthly advance in kWh, from the regular meter, can be calculated the power factor and hence the penalty, if any.

3. Other metering arrangements could have been used in West Pakistan based on alternative definitions of power factor but generally these alternatives are more expensive in first cost and more difficult to keep in good order.

4. However, it is not at all clear to the consumer, nor perhaps to WAPDA staff, what the significance is of an incremental advance of the KVArh (reactive) meter since the functional relationship 1/ between the KVArh advance, the kWh advance, and the estimate of power factor is a complex one. Fortunately a linear approximation has been derived which is sufficiently accurate over the working range to aid understanding of the power factor penalty.

5. If the KVArh advance is no greater than 62% of the kWh advance, no penalty applies.

6. Otherwise the percentage penalty (varied for Rate 2 of Tariff B5) is approximated by (150 KVArh - 93 kWh)/4 kWh ... (1) applicable down to power factors of 60% where the penalty reaches 25% of the maximum demand charge.

7. From this approximation, linear in KVArh, the price per incremental KVArh once the free block of 62% of the kWh has been consumed is estimated to be 1.3 paisa per KVArh ... (2) for an 11 kV consumer typically paying 15 rupees per kW of monthly maximum demand and having a monthly load factor of 60%.

1/ Cosine of the inverse tangent of the ratio KVArh to kWh.

8. For Tariff B3 -- 11 kV industrial supplies -- the price per kWh is 7.5 paisa so that in contrast to this energy rate, the price per unit advance of the KVArh meter is either zero or about one-sixth.

9. For precise calculation for billing purposes, WAPDA may find the following table helpful where the meter ratio is obtained from the KVArh monthly advance divided by the kWh monthly advance.

CALCULATION OF POWER FACTOR

Meter Ratio	Power Factor	Meter Ratio	Power Factor	Meter Ratio	Power Factor	Meter Ratio	Power Factor
0.000	1.00	0.567	0.87	0.909	0.74	1.299	0.61
0.142	0.99	0.593	0.86	0.936	0.73	1.334	0.60
0.203	0.98	0.620	0.85	0.964	0.72	1.369	0.59
0.251	0.97	0.646	0.84	0.992	0.71	1.405	0.58
0.292	0.96	0.672	0.83	1.020	0.70	1.442	0.57
0.329	0.95	0.698	0.82	1.049	0.69	1.480	0.56
0.363	0.94	0.724	0.81	1.078	0.68	1.519	0.55
0.395	0.93	0.750	0.80	1.108	0.67	1.559	0.54
0.426	0.92	0.776	0.79	1.138	0.66	1.600	0.53
0.456	0.91	0.802	0.78	1.169	0.65	1.643	0.52
0.484	0.90	0.829	0.77	1.200	0.64	1.687	0.51
0.512	0.89	0.855	0.76	1.232	0.63		
0.540	0.88	0.882	0.75	1.264	0.62		

GUIDE PRICES OF ELECTRICITY METERS AND

ASSOCIATED HARDWARE

1. The following prices have been obtained mainly from two British manufacturers and hence are first given in pounds sterling. The same hardware can, of course, often be obtained from other countries, especially Switzerland. It was thought advantageous, however, to obtain guide prices from suppliers who were well-known to the consultant and were likely to be cooperative.

2. Discounts are obtainable. One supplier said "it depends on the item, its destination and quantity", whereas the other said:

1 - 499	Standard price
500 - 999	5% discount
1,000 - 1,999	10% discount
2,000 or more	20% discount

3. Timeswitches may be heavily discounted with bulk buying. For example, the synchronous spring-reserve one listed here at £ 22 (US$53) is purchased by Electricity Boards in Britain for as little as £ 12 (US$29). In Belgium BF 2,000 is paid or just under £ 17 (US$40). The prices of timeswitches seem to show greater instability than those of meters, probably because the market is even more specialized and there is even greater product differentiation.

4. Additionally there are delivery charges, import duties and other taxation, and the cost of foreign exchange.

STANDARD PATTERN INDOOR KILOWATT-HOUR METERS

Rating Amperes	One element Single-phase 2-wire 50 - 260 Volts 50 cycles £	US$	Rating Amperes	Two elements 3-phase 3-wire 110 - 450 Volts 50 cycles £	US$	Three elements 3-phase 4-wire 50 - 260 Volts 50 cycles £	US$
10	4.20	10	5 or 10	11.00	26	15.00	36
40	4.20	10	25	12.00	29	16.95	41
80	4.20	10	50	13.15	32	20.60	49
100	8.40	20	100	25.20	60	33.15	80

METERS COMPLETE AND CALIBRATED WITH CURRENT TRANSFORMERS INSULATED FOR UP TO 650 VOLTS

	£	US$		£	US$	£	US$
100/5	13.50	32	100/5	26.65	64	37.00	89
200/5	12.50	30	200/5	23.00	55	32.00	77
300/5	11.40	27	300/5	22.50	54	30.70	74
400/5	11.40	27	400/5	22.50	54	30.70	74
500/5	11.40	27	500/5	22.50	54	30.70	74

EXTRAS TO ABOVE PRICES	£	US$
To measure KVArh rather than kWh from	2.00	5
to	11.50	28
Maximum demand indicator		
with internal time control	22.00	53
without internal time control	16.70	40
Two-rate registers*	4.35	10
Three-rate register+	8.00	19
Load-rate register**	8.00	19
Reverse-rotation ratchet	0.70	1.7
Switchboard mounting	8.65	21

* Most readily obtainable from British sources
\+ Obtainable from French and Swiss sources
** Obtainable from Norwegian and Swiss sources

PREPAYMENT METERS (50 - 260 Volts, 50 cycles, Single-phase Two-Wire)

TYPE	RATING AMPERES	COIN+	ENERGY RATE	METER PRICE £	US$
Without fixed-charge collector	10 or 40	5p and 10p	Variable 0.5p to 4p or 1p to 8p	11.80	28
With fixed-charge collector*	10 or 40	5p and 10p	Variable 0.5p to 4p or 1p to 8p	15.35	37

+ British new pence. A 10p coin is roughly a US quarter dollar.
* To collect weekly fixed charges ranging up to £2.60 or, say, US$6.

TIMESWITCHES

	£	US$
Synchronous Motor, without Spring Reserve		
Single-pole 30 A contacts on one circuit	6.40	15
Seasonal dial instead of 24-hour dial	7.00	17
Synchronous Motor, with Spring Reserve		
Single-pole 80 A contacts on one circuit	22.00	53
Arranged for sophisticated seasonal-time-of-day rate	27.00	65
Escapement, 15-day Hand Wound		
Single-pole 10 A contacts on one circuit	20.00	48
Escapement, Mains Wound		
Single-pole 20-30 A contacts on one circuit	13.25*	32*
or	19.80	48

* Minimum specification

COST OF TELECONTROL AND

COMPARISON WITH TIMESWITCH CONTROL

1. The following sources of data were used:

"Experience in Centralized Telecontrol", E. Michez and W. Schmucki, Cannes Congress, September 1970, UNIPEDE.

"Field Trials of Telecontrol", G. S. Johns, Electricity Council Research, June 1969.

Letters dated 5th June from the Chief Engineer, Midlands Electricity Board, England and 9th of June from the Chief Engineer, The East African Power and Lighting Co. Ltd., Nairobi, Kenya.

The first source gives cost data for Portugal, Belgium and France, and the second, amplified by the first letter, gives data for Britain.

2. Three ways of expressing the cost of injection equipment were found to be in use: the cost per MVA of load, the cost per MVA of bulk-supply transformer capacity (total possible input), and the cost per KVA of the ripple generator capacity. However, some rough relationships were used to bring the data to a common basis of cost per MVA of consumers' demand.

3. For the injection equipment, the assumption is that the costs of land, buildings, other civil works and installation costs are included, as is a proportion of overhead charges. In the one case where these are known separately, the bare cost of the injection equipment had to be roughly doubled to give the total cost.

4. An overall view of the cost data taking up a medium position is:

Injection equipment, installed	US$750 per MVA of load
Purchase of receivers	US$ 35 per item
Purchase of timeswitches	US$ 40 per item

A naive breakeven calculation, assuming that maintenance costs are not greatly different for the alternatives and that the economic lives of the three items are much the same, runs

$$\text{Breakeven density of application} = \frac{750}{40-35}$$
$$= 150 \text{ receivers per MVA of system demand}$$

5. This calculation is crucially dependent on the relative costs of timeswitches and telecontrol receivers. The above relativities are mainly based upon a careful evaluation in Britain using a large-scale experiment in the area of Midlands Electricity Board. Experience in Nairobi, where the "Rythmatic Ripple Control" system of Plessey, New Zealand, is used, puts the price of receivers as 30% cheaper than timeswitches, but import duty is levied on the latter item only. If the maintenance costs of the telecontrol installation, including the central injection equipment, were less than those of the equivalent installation of timeswitches, then the breakeven number would be reduced. Annex 13, however, sets out some of the difficulties found in practice with telecontrol which should be reflected in the cost relativities.

6. If this naive calculation were to be refined, an important modification would be to consider the dynamic situation. In particular:

Item	Favors Timeswitches	Favors Telecontrol
1.	Slow start to application	Fast get away
2.	Uncertainty of extent of application	Certainty of extent of application
3.	Retraction likely after a trial period	Retraction unlikely
4.	Fast system load growth	Slow system load growth

7. The last item is often overlooked. The capacity of the central injection equipment has to keep pace with the growth of demand because the signal is, in fact, consumed by lights, appliances and motors. Many of the difficulties experienced in practice with telecontrol installations after a few years arise because the capacity of the injection equipment is not sympathetically increased with the growth of system demand. The transmitted signal has to reach the consumer with an adequate voltage more than sufficient to be clearly differentiated from the "noise" on the

power system. A high signal noise ratio is essential to the proper working of a telecontrol system. 1/

8. A broad guide is that one KVA of injection capacity has to be added for every one MVA increment of system demand. 2/ It follows that those systems with rapid growth of system demand must match this growth with the installation of signal injection equipment. It is believed that the non-implementation of this policy led to the abandonment of nearly all the telecontrol installations in Britain, broadly over the years 1930-1960. Another contributory cause was the technical failure of many systems when it was found that the receivers had not been designed to discriminate against the spurious signals found on supply networks.

1/ "The equipment that we have been using has not always been satisfactory, particularly in the remoter areas where on occasions timeswitches have had to be installed in lieu of 'Rythmatic' receivers. About a year ago we had considerable complaints of failure, but on retuning of the equipment complaints decreased abruptly to a negligible level.

"In view of these complaints we have considered that more powerful injection apparatus will be required and we have approached the manufacturer for their views. At present the receiver relays are about 30% cheaper than timeswitches as we are required to pay duty on the latter and in view of the facility of being able to control load to meet the remainder of the system requirements we think that the cost of the injection system is justified."

Extract from the letter from the East African Power and Lighting Co.

2/ Not the demand being controlled but the total demand.

SOME MAINTENANCE AND OPERATIONAL DIFFICULTIES

EXPERIENCED WITH TELECONTROL

1. In the early stages of the development of telecontrol it was thought that the power system voltage at 50 Hz was complemented only by some multiple frequencies, called harmonics, and an occasional surge of short duration and of little importance. For example, the injection of a direct current, d.c., signal was thought immediately to lead to a recognizable signal by a low-cost receiver. The argument was that an a.c. supply system does not supply d.c. However, d.c. voltages are found on a.c. systems and in particular the widespread use of television receivers led to an increasing d.c. component. In consequence the use of this type of signal for telecontrol was dropped, and the investment in injection and receiving apparatus proved abortive.

2. Three approaches are used to deal with the problem of recognizing a valid signal against a background of unwanted signals, called noise. The sources of this noise will be set out later but meanwhile it should be accepted that power systems contain voltages of various frequencies which low-cost receivers might sometimes confuse with valid signals. The first approach is to use a receiver of limited sensitivity, well above the threshold of noise -- this, of course, is reflected in the cost of the central equipment, which is required to generate a strong signal of, say, 5% of the power voltage. The second approach is to delay the response of the receiver so that a valid signal is one of long duration, say 50 to 500 milli-seconds, whereas noise (imitating the correct frequency) is usually of shorter duration. The third approach is to increase the selectivity of the receiver by adding a code to the recognition of the correct frequency.

3. One system already described uses a code of two signals spaced by a few seconds: a valid signal is recognized as having the correct time spacing. Another uses a low-frequency modulation of the audio-frequency signal, and both frequencies have to be simultaneously correct for the recognition of a valid signal. With such coding, the problem of spurious response is greatly reduced.

4. Various sources of unwanted signals or noise have been recorded. These have caused spurious operation of telecontrol receivers, though the extent to which these receivers were coded or otherwise arranged to reject unwanted signals is not known. Mercury arc rectifiers which are often used for traction supplies were mentioned as giving trouble in Switzerland, the Netherlands, Portugal and Belgium. In one case, a voltage as high as 5% of the system voltage was present at a frequency of 550 Hz. Similarly mercury vapor lamps as used for street lighting have been known to generate unwanted signals of sufficient magnitude to operate telecontrol receivers.

Welding transformers have been mentioned as a source of unwanted signals, and under certain circumstances the ordinary induction motor, especially when connected at the end of a long overhead line, can cause improper operation of a local telecontrol receiver. This last comment seems particularly appropriate to West Pakistan if telecontrol is to be considered for the disconnection of tubewells.

5. The converse to unwanted signals is the loss of the wanted signals. This particularly arises where capacitors are installed for power factor improvement since these act as a sink to absorb ripple signals. Another sink for ripple signals is the power system itself required to give the 50 Hz supply. The injected signal flows not only towards the consumer, and hence towards the receiving relay, but also flows back towards the power stations. Under certain circumstances, this backwards drain can be unusually high and can prevent the dispatch of a sufficient signal strength in the desired direction. In particular, where a small generating station is to be found at the end of a long line (tail-end generation) then the ripple signal will tend to be absorbed by the remote generator.

6. These problems of unwanted signal generation or unwanted signal absorption can be overcome by the use of filter circuits. Obviously, however, the identification of these problems and the installation of filters are continuing expenditures over the life of the installation, that is, maintenance costs.

7. While generally the claim that receivers are reliable and give little trouble is accepted, there are exceptions. The receivers are tuned to respond to the correct frequency and can drift out of adjustment. Windings can burn out and capacitors short circuit. While these problems should not be exaggerated, it has to be accepted that receivers will require periodic attention over their life of, say, 15 years. Receivers have been most frequently employed to control either meter registers or domestic water heaters of 2 kW or 3 kW loadings. Where receivers are required to control loads of, say, 5 kW and above, it is likely that the switching contacts will also require periodic attention.