ECONOMIC ANALYSIS OF INVESTMENT IN POWER SYSTEMS

by

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June 1991

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INTRODUCTORY NOTE

The Asian Development Bank Staff Paper Series presents the results of selected preliminary research undertaken by the Economics and Development Resource Center. It is designed to stimulate discussion and critical comment on socioeconomic issues facing the developing countries of Asia and the Pacific. It is hoped that in some small way the discussion generated by the series will increase our understanding of the development process in the region.

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ACKNOWLEDGEMENT

The author wishes to thank Messrs. A.I.A. Islam, P.N. Fernando and K. Nyman for their detailed, constructive and thought provoking comments on an earlier version of the paper. In addition, the author acknowledges the suggestions from Messrs. J.S. Lee, R.O. Wada, J.M. Dowling, Ba Lay, P. Choynowski and R. Noakes. However, the author is solely responsible for opinions expressed and shortcomings that remain. The author also wishes to thank Ms. Arlene Tadle for competent research assistance and Ms. Marinie Baguisa for dedicated and skillful typing of many drafts of the paper.
ABSTRACT

Power systems consist of integrated networks of generation, main transmission and local distribution components. The intra and intertemporal dependence of these components make it desirable to take a systems approach to investment planning which should aim at maximization of net benefits. The process of maximization of net benefits for the power system as a whole can be viewed as consisting of four modules. First, given the existing power system configuration and the load and energy demands associated with an electricity tariff forecast, alternative system expansion plans and their costs can be simulated. Second, from the alternative system expansion plans the least-cost system expansion plan is determined along with the associated long-run marginal cost of supply. Third, given the energy demands used in determining the least-cost expansion plan, cost-benefit analysis is undertaken to judge the economic viability of the least-cost investment plan. Fourth, the marginal cost of supply is compared with the electricity tariff forecast to revise the latter on the basis of which a new load and energy demand forecast is prepared incorporating the tariff change. The process described above is repeated until an investment plan emerges where electricity tariff and long run marginal cost are equal. An efficient and economically viable power sector investment plan will evolve where the interaction of the demand forecast, investment decision and the accompanying long run marginal cost of supply is accounted for explicitly.

Much of the literature and practice on power sector investment have emphasized least-cost system expansion planning. It rarely adopts the four module approach described above. Instead, the analysis stops at the second module with the demand and reliability levels being predetermined. The problem of maximization of net benefits is reduced to minimization of costs to meet certain power and energy demands at specified reliability levels.

The main purpose of the paper is to design an approach which will indicate how information available from current practices in investment planning in the power sector can be exploited to conduct rigorous cost-benefit analysis. The contribution of the paper lies in extending the analysis to the third module where net benefit maximization occurs at a given level and structure of tariffs. It provides the interface between least-cost and cost-benefit analysis in the power sector by using information contained in the least-cost investment plan to identify and quantify benefits. By itself, least-cost analysis says nothing about the economic merits of an investment program or project since even a least-cost program may have costs that exceed its benefits. Whenever possible, it is necessary to consider whether benefits are adequate. Hence, least-cost analysis is a necessary but not sufficient condition for maximization of net benefits. Both least-cost and cost-benefit analysis are required together to ensure maximization of net benefits. By highlighting the issues involved in making the transition from least-cost to cost benefit analysis in power sector investment
planning, the paper provides a feasible and more rigorous approach to economic analysis of investment in power system. It addresses the problem of the comparison of costs and benefits in the power sector to determine the volume of investment to the power sector and its allocation within its major components.

The core of investment planning in the power sector is the least-cost analysis which is used in choosing the design and volume of investment in a manner that minimizes system cost while meeting given requirements of load and reliability. Given the complexities arising from intra-temporal and inter-temporal interdependence of various components of the power system, in practice, least-cost analysis is usually conducted separately at the subsystem level for generation, transmission and distribution. Both optimization and consistency approaches are used at the subsystem level. While a consistency approach ensures technical feasibility, the optimization approach minimizes cost subject to ensuring technical feasibility of a power system or subsystem. It is the nature of investment planning at the subsystem level in terms of adopting a consistency or optimization approach that will determine the rigor of the economic analysis that will be possible.

An integral part of the least-cost analysis is the demand forecast for power and electricity. It has been assumed throughout the paper that demand forecasts are available. Improved demand forecasts permit significant resource savings through better selection and timing of major generation, transmission and distribution investments. Therefore, electricity demand studies have potentially very high returns and should be conducted prior to conducting subsystem and power development planning.

The solution to the least-cost analysis is the starting point for analyzing benefits which consist mainly of resource cost savings, additionality of supply and improved quality of supply. While the valuation of benefits is market-oriented, the allocation of benefits in terms of identification and quantification is project-oriented. The interdependence of power projects may make it difficult to allocate or assign benefits to investment projects. In this case, a system or program approach to cost-benefit analysis becomes inevitable. It would be important to distinguish whether this interdependence refers to the power development plan consisting of generation, transmission and distribution or whether it deals with interdependence within a subsystem.

The analytically rigorous rationale for conducting cost-benefit or economic analysis using the system time-slice approach rests on project interdependence at the intratemporal and intertemporal levels. Given that least-cost investment planning in the power sector is done separately at the generation, transmission and distribution subsystem levels, the time-slice analysis is particularly applicable at these subsystem levels. This happens because intra subsystem interdependencies are specifically taken into consideration in optimization or technical feasibility analysis at the subsystem level during the process of investment planning for generation, transmission and distribution. However, only when inter-
subsystem interdependences are taken into account is the time-slice analysis for the power development plan as a whole meaningful.

One implication of using piecemeal cost-minimization or optimization at the subsystem level for investment planning is that such optimization does not guarantee that the best overall plan of the system is found. Optimization helps in searching through alternative plans, but if the scope of the analysis is such that it considers only one aspect of the planning problem, the optimal solution determined may not be part of the best overall plan.

The issue of project interdependence, which makes it difficult to allocate benefits across projects, raises a problem in the financing of investment in power systems. Financing is frequently project related. A rate of return for a project could be required for taking a decision on financing. In cases where the problem of common benefit makes it difficult to estimate a rate of return for a project which is under consideration for financing, all that can be done would be to establish viability of the system or program investment and ensure that the project constitutes an integral part of the least-cost solution of the system or subsystem under consideration. The issues of project interdependence and project boundary are related. It would be crucial to explicitly define the boundary under consideration in terms of the (i) power development plan consisting of the aggregate investment in generation, transmission and distribution or (ii) investment in one of the power subsystems. The project under consideration should be a least-cost solution to either (i) or (ii).

While system interdependence resulting in common benefits may require a program or system approach to economic analysis, in many cases a partial analysis of projects may still be possible if the subsystem least-cost analysis had been rigorously conducted. In a systems approach to least-cost generation planning, the output profile of a project taking into account project interdependencies would be available. Given this information, economic analysis at the project level can be done to identify and modify, if necessary, projects which are at the margin of a power development plan.
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I. INTRODUCTION

1. Investments in power systems generally are highly capital and import intensive and account for a significant share of public investment in most developing countries. With the emergence of electricity as a universal intermediate input whose demand is rapidly growing there are increasing pressures on power utilities to increase and improve their quantity and quality of supply. However, there are concerns about their financial viability and resource mobilization efforts which would influence their ability to respond to the demands made on them. These concerns have arisen from the economic environment facing power utilities in many developing countries.

2. The economic environment within which the power sector operates in a developing country is influenced by six main factors. First, electricity tariffs serve as incentives on the basis of which consumption decisions are based and constitute the main source of revenue to the power utilities. Second, inputs like fuel oil, water and equipment for generation, transmission and distribution are needed for production. Third, innovation in technology is required. Fourth, information for the diffusion of technological knowledge is important. Fifth, infrastructure in the form of roads, railways and ports are needed for transporting equipment and intermediate inputs to power utilities. Lastly, institutions within the power sector for efficient planning, production and marketing are necessary. A consideration of these six factors will be required to assess the economic environment facing the power sector in a country. It is the interaction of price, institutional and investment variables among the six factors and changes in them which will mainly influence supply responses from the power sector.

3. Power sector adjustment will have three major components, namely, reforms in policies and institutions, and rationalization of investment programs. The timing and sequencing of reforms should be designed in the context of a sector strategy which is underpinned by rigorous sector analysis. These reforms and rationalization are likely to be spread out over a considerable length of time and there will be interactions among them. This implies that, on the one hand, policy distortions are likely to remain and on the other, the interactions among the reforms should be taken into account in assessing sector adjustment. The presence of distortions leads to the need for the economic analysis of investment in the power sector. The focus of this paper is on the economic analysis of investment in the power sector with a view to facilitating both inter- and intra-sectoral allocation of investible resources. While the issues of policy and institutional reform in the power sector are important subjects, they are outside the scope of this paper.

4. Given that the power sector accounts for a significant proportion of the gross capital formation and of public sector investment in most developing countries, there is a need to carefully design investment decisions in it. This task, however, is complicated by both supply and demand aspects. On the supply side, power systems consist of
integrated networks of generation, main transmission and local distribution components. This interdependence of power projects makes it desirable to take a systems approach to investment planning. While analytically elegant, however, a systems approach is highly complex. On the demand side, electricity is an input for various uses like heat, light and motor power and serves different markets such as household, commercial, industrial and agricultural sectors. While electricity maybe homogeneous from a physical viewpoint, the demand side considerations make it a heterogeneous product from an economic viewpoint. Hence, there is a need to provide an interface between the demand and supply aspects in a manner which adequately incorporates the characteristics of both in the design of investment planning in the power sector.

5. Rapid advances in computer hardwares and softwares have made it possible to plan certain aspects of power sector investment programs intertemporally in the framework of a systems approach. Two points are noteworthy. First, given the complexity on the supply side, the feasible approaches to power sector investment planning have taken the form of hierarchical subsystem analysis in terms of relatively independent treatment of generation, transmission and distribution components. Second, power sector investment planning in the form of determining a least-cost investment program to meet certain load and energy demands at predetermined levels of reliability has been frequently undertaken. Explicit considerations of costs and benefits in a systems framework with maximization of net benefits as the objective have been rare.

6. The main purpose of the paper is to design an approach which will indicate how information available from current practices in investment planning in the power sector can be exploited to conduct rigorous cost-benefit analysis. The contribution of the paper lies in extending the analysis to incorporate net benefit maximization at a given level and structure of tariffs. It provides the interface between least-cost and cost-benefit analysis in the power sector by using information contained in the least-cost investment plan to identify and quantify benefits. By itself, least-cost analysis says nothing about the economic merits of an investment program or project since even a least-cost program may have costs that exceed its benefits. Whenever possible, it is necessary to consider whether benefits are adequate. Hence, least-cost analysis is a necessary but not sufficient condition for maximization of net benefits. Both least-cost and cost-benefit analysis are required together to ensure maximization of net benefits. By highlighting the issues involved in making the transition from least-cost to cost benefit analysis in power sector investment planning, the paper provides a feasible and more rigorous approach to economic analysis of investment in power system. It addresses the problem of the comparison of costs and benefits in the power sector to determine the volume of investment to the power sector and its allocation within its major components.

7. Investment planning in the power sector can be viewed as a dynamic non-linear programming problem. Against this background, a general framework is described decomposing the problem in two ways. First, maximization of net benefits can be viewed as consisting of several
distinct but interrelated modules. Second, the generation, transmission and distribution components are examined separately but with a view to integration and coordination. The framework provides a benchmark against which existing approaches to investment planning in the power sector can be assessed, the advantages of the approach suggested over the existing ones determined and the areas for improvements in the suggested approach identified.

With a framework of analysis established, the paper considers various aspects of demand forecasts for electricity. The link of the demand forecast to both the least-cost and cost-benefit analysis is established. Least-cost analysis which constitutes the core of investment planning in the power sector is considered next. This is followed by a discussion of cost-benefit analysis and its relationship to least-cost investment planning. The interdependence of power projects causing difficulties for allocation of benefits to specific projects is explicitly considered to provide insights to the issue of the systems versus projects approach to economic analysis of power sector investment.

II. A GENERAL FRAMEWORK

The purpose of an electric power system is to supply electricity to consumers at a power level that they desire and at a time and place of their choosing while maintaining an acceptable quality of service. Quality of service is defined in terms of specified limits within which voltage and frequency levels must lie. The basic elements of a power system can be described in terms of their functions, namely, generation, transmission and distribution. The concept of a generation service in terms of a hydro, thermal or nuclear power plant is straightforward. The transmission and distribution facilities convey the electric power from the generation point to the consumer or the load point. Transmission lines carry large amounts of power over long distances. In contrast, distribution lines carry smaller power flows over shorter distances. The distinction between transmission and distribution facilities is often made on the basis of their operating voltages. A simple power system could take the following form.

The output from a generation plant would be fed into the transmission facilities whose main components consist of power transformers, high and extra high voltage transmission lines and transmission substations. Output from a generation plant is increased to high voltage at the generation source by power transformers and fed into bus bars at transmission substations through transmission lines. At the transmission substations, the voltage could be further stepped up to extra high voltage and the electric power carried further by transmission lines before being fed into another substation which could reduce the voltage before the electric power is fed through transmission lines to the distribution facilities. These mainly consist of distribution substations, primary feeders, distribution transformers and secondary lines. The voltage of the electric power received from the transmission
facilities is reduced at the distribution substations which are located close to the load points or centers. Primary feeders are used to evacuate power flows out of distribution station bus bars to distribution transformers where the voltage is reduced again. The consumer receives electric power from a secondary distribution line, a service inlet and a meter.

11. Even in the simple case described, the components required from generation or injection point to load or extraction point are many and complicated. A power system is generally much more complex with many generating points linked to many load points through an interconnected transmission network. Further, the distribution facilities or a single load point could serve thousands of consumers.

12. This brief description of the power system implies that the nature of the problem faced in each component is likely to be different. For example, in a distribution system, against the background of minute details of a small geographic area, distribution planning is carried out for many small components like distribution transformers and switches. In contrast, generation planning is undertaken at a global or national level and deals with large components. On account of both the complexity of a power system and the fact that the nature of the problems arising in each component could be significantly different, investment planning is frequently undertaken in terms of the major components: generation, transmission and distribution. In practice, a power sector development plan is built up through subsector or subsystem planning of generation, transmission and distribution rather than the simultaneous and integrated planning of the three components.

13. While generation, transmission and distribution planning is normally conducted separately, it is recognized that these three aspects of power system planning should be integrated and coordinated. Investment planning may not be simultaneous but it should be interactive. For example, generation planning typically incorporates related transmission requirements. The interactions between generation and transmission will be greater than between these two components and distribution. Hence, while power distribution is part of the system, it is more distinct than transmission is to generation.

14. Against this background, investment planning in the power sector can be viewed as a problem in operations research. It can be posed as a dynamic non-linear programming problem. The objective would be to maximize benefits. The constraints would include capacity endowments, technical performance requirements, system configuration among generation, transmission and distribution components, etc. Alternatively, the problem can be viewed as maximization of net benefits. Net benefit could be defined as total benefits of electricity consumption minus system costs minus costs to consumers of supply shortages. While total benefits would depend on demand, system costs and costs to consumers would depend on
demand and reliability.\textsuperscript{1} In such a system, for a given level of demand, net benefits of electricity consumption would be maximized when the quality of supply is increased to the point where the marginal increase in system costs due to quality improvements is equal to the marginal decrease in the costs of poor quality supply plus the increase in the benefits of induced demand. This outcome for power system optimization or maximization of net benefits is sufficiently general to be applicable to all levels of power system planning, that is, for generation, transmission and distribution.

15. The process of maximization of net benefits for the power system as a whole can be decomposed into four modules. First, given the existing power system configuration and the load and energy demands associated with an electricity tariff forecast, alternative system expansion plans and their costs can be simulated. Second, the least-cost system expansion plan is determined along with the associated long run marginal cost of supply. Third, given the energy demands used in determining the least-cost expansion plan, cost-benefit analysis is undertaken to judge the economic viability of the least-cost investment plan. Fourth, the marginal cost of supply is compared with the electricity tariff forecast to revise the latter on the basis of which a new load and energy demand forecast is prepared incorporating the tariff change. The process described above is repeated until an investment plan emerges where electricity tariff and long run marginal cost are equal. An efficient and economically viable power sector investment plan will emerge where the interaction of the demand forecast, investment decision and the accompanying long run marginal cost of supply is accounted for explicitly.

16. When power sector investment planning is conducted using the four module approach described, tariffs at the margin are equated to long run marginal cost at the optimum. Viability of the investment program and the optimum tariff setting in the planning framework become synonymous. Furthermore, demand and supply of electricity would be equated to ensure power system equilibrium. In that sense, the non-linear programming solution simulates a perfectly competitive market system for the power sector

17. Within the four modules, it was implicitly assumed that in the dynamic non-linear programming approach, generation, transmission and distribution components were being simultaneously considered. A decomposition into generation, transmission and distribution with only the major interactions considered in an iterative manner could be followed.

18. The advantage of decomposing the operations research problem in the two ways described is that the general framework can then be used to assess current practices in power sector investment planning and to identify areas for improvement. In practice, the process of power sector investment planning rarely adopts the four module approach described

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above. Instead, demand and reliability levels are predetermined. The problem of maximization of net benefits is reduced to minimization of costs to meet certain power and energy demands at specified reliability levels. Much of the literature and practice on power sector investment have emphasized least-cost system expansion planning. In terms of the four modules described earlier, current practice in investment planning stops at the second module.

19. The practice of least-cost investment planning is general enough to be applicable to all levels of power system planning, that is, for generation, transmission and distribution. In this context, it should be noted that in the least-cost investment planning approach in the power sector, alternative investment possibilities together with the existing power system configuration play a crucial role in simulating alternative system expansion plans which meet predetermined power and energy demands and reliability levels. The system simulations generate feasible or consistent technical alternatives. These should be contrasted with the optimization process that selects the least-cost of the feasible or consistent alternatives. Further, for each of the three components, the optimization process could lead to the estimation of marginal costs for generation, transmission and distribution.

20. As indicated in Section I, cost minimization is a necessary but not sufficient condition for economic viability. In this paper, the analysis is extended to the third module. This implies that given energy demands and the least-cost investment plan, a cost-benefit analysis is undertaken to assess economic viability of the investment plan. Since power and energy demands are taken as given, no attempt is made to relate marginal cost of supply to electricity tariff and account for demand changes arising from tariff revisions made necessary by the investment plan. This description of the approach adopted for power sector investment in the paper indicates the use of a constrained least-cost optimization approach. The cost-benefit analysis is superimposed exogenously as the demand forecast which determines the benefit stream is unaffected by the least-cost investment plan. This approach ensures that benefits exceed costs. The goal is to achieve net benefit maximization at a given level and structure of tariffs.

21. The main limitation of the paper stems from the fact that the analysis is not extended to the fourth module. The impact of a change in marginal cost on tariff and hence on demand is not considered here. Incorporating this feedback would imply a full-scale systems analysis which is beyond the scope of the paper. Therefore, first-best benefit maximization need not follow. Instead, the approach adopted is that given the existing policy and institutional environment, will an investment program or project be economically viable.

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22. The description of the integrated nature of the power system and the stages involved in investment planning through the maximization of net benefits provides a framework of analysis and a benchmark against which current practices in power sector investment planning can be assessed. Since a full fledged systems approach with maximization of net benefits is the exception rather than the rule, a question that comes up is under what conditions will a hierarchical approach with generation, transmission and distribution planning of investment being planned separately be justified. Investment planning in generation alone is justified if there are no constraints on transmission and distribution while investment planning in transmission by itself can be undertaken when there are no constraints on generation and distribution. Similarly, investment planning for distribution alone can be justified if there are no constraints on generation and transmission. While these conditions are stringent, the rationale of a binding constraint may need to be invoked to make investment planning in the power sector approach feasible through the adoption of a hierarchical or subsystem approach.

23. A relevant issue that comes up as a result is whether it is possible to judge the viability of an investment project consisting of one or more components of the power sector development plan of a developing country. One line of reasoning could be that if the entire power development plan is viable and the component under consideration is an integral part of the least-cost investment plan, the project under consideration should be financed. In this context, two observations are pertinent. First, the maximization of net benefits in a fully integrated systems approach to power sector development plan is rarely feasible and hardly ever undertaken. Second, in the hierarchical approach, cost minimization with each component being independently treated is usually considered. For example, if a transmission component of a power development plan is under consideration, how should it be assessed to determine its viability? The paper will provide some insights into the considerations on which a judgment could be made on when a systems or a project approach to investment planning in the power sector is meaningful.

24. In terms of the general framework described, sections III and IV deal with issues relevant for the first two modules, namely, given a demand forecast, how is the least-cost solution determined. Section V links the discussion on current practices in power sector investment planning with the identification, quantification and valuation of benefits in Section VI. In Section VII, some important and useful insights are drawn from the economic analysis of investment in the power sector for the determination of long-run marginal costs of electricity generation, transmission and distribution. In turn, these long-run marginal costs have a direct bearing on policies dealing with tariff setting. The paper concludes by identifying further areas of improvement that will be needed in undertaking adjustment in the power sector.
III. DEMAND FORECAST FOR ELECTRICITY

25. A variety of factors makes it important to have accurate demand forecasts for electricity. If forecasts are too low, shortages of electricity may occur and their costs will usually be a large multiple of electricity not supplied. On the other hand, if forecasts are too high, large amounts of capital with high opportunity costs could be inoptimally allocated. The costs of these two outcomes will be much greater to the economy than the resources required to undertake reliable demand forecasts for electricity. The demand forecasts establish the need for electricity and these play a critical role in both the least-cost and the cost-benefit or economic analysis of power sector investment planning.

26. The characteristics of the power sector determine the time horizon and the structure of demand forecasts that are required. Short to medium-term forecasts between one and three years and four to eight years, respectively, are required for distribution system planning. Medium-term forecasts of four to eight years correspond to the lead times needed for transmission and generation projects. Long-run system expansion planning requires long-term demand forecasts spanning ten to thirty years. Since investment planning in the power sector is long-run in nature, the emphasis is usually on long-term demand forecasts for electricity.

27. The major components of the power sector indicate the importance of the structure of demand which includes disaggregation by geographical area, by consumer category and over time. Disaggregated demand forecasts are crucial in the system planning process. While generation planning for a power system is modeled on the basis of one point source meeting one aggregate load and energy demand, the characteristics of demand by region and major load centers are important in the design of transmission networks. A detailed knowledge of demand at each load center is required for distribution grid planning. Disaggregated demand forecasts are useful for two reasons. First, the sum of the disaggregated demand forecasts for different load centers within a region can serve as a useful check on a global forecast which is independently estimated for the region. Second, disaggregated forecasts are crucial in determining the benefits of investment in the power sector.

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The discussion in this Section is focused on demand forecasting using an econometric approach. The reason for doing so is two-fold. First, this approach is the most complete. Second, it enables the inclusion of income and price as explanatory variables. This is crucial in benefit estimation. In practice, a number of other techniques like trend analysis, end-use approach and time-series analysis are also used for electricity demand forecasting.
28. In forecasting the demand for electricity, it is useful to draw a distinction between established and new markets. In established markets, electricity is already available to consumers and the demand forecast will be designed to utilize information that is already available from time-series data. The characteristic of a new market is that without the project, electricity would not be available to consumers who are using other sources of energy like kerosene for lighting and diesel pumps for agricultural production. The introduction of electricity in the new market will result in the substitution of other forms of energy as well as major changes in the quality and quantity of energy consumed. Thus, the demand forecast in a new market is likely to be significantly different from an established market.

29. A considerable amount of literature exists on the empirical estimation of electricity demand functions in established markets. Some of the major issues will be highlighted. The most important factor in the estimation of electricity demand functions will be the availability of data which will greatly influence the explanatory variables used and the reliability of the results. The major explanatory variables will differ by categories of users like residential, commercial, industrial, agricultural and public sectors (see attached Table). At the minimum, electricity demand forecasts should include as explanatory variables some measures of income or output, the price of electricity and the price of the most important substitute fuel, e.g., kerosene for lighting. These variables should be expressed in constant prices whereby current prices are deflated by an appropriate price index to enable the assessment of the impact of relative price changes on electricity demand.

30. The income variable should vary by consumer category. Per household or per capita income could be used for the household sector. Sectoral output, value added or employment are applicable as indicators


4/ Prices are expressed in real terms because the demand function is assessed to be homogeneous of degree zero.
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**A. Residential Sector**

1. Number of households (or population)
2. Real family income
3. Price of electricity
4. Connection charges
5. Availability of service (urban, rural)
6. Reliability of service
7. Cost and availability of electricity-using fixtures and appliances
8. Availability and cost of consumer credit
9. Costs of alternative energy source (kerosene, LPG, natural gas, charcoal, firewood, coal)

**B. Commercial Sector**

1. Sales of value-added of nonsubsistence commercial sector
2. Price of electricity
3. Connection charges
4. Reliability of service
5. Working hours of various types of commercial establishments

**C. Industrial Sector**

1. Price of electricity (demand and energy charges by type of service)
2. Type of industry and its electric intensity
3. Degree of market power of individual industry
4. Relative price of alternative energy sources
5. Reliability of supply
6. Comparative total costs of autogeneration
7. Availability

**D. Agricultural Sector**

1. Price of electricity
2. Availability
3. Reliability of service
4. Supply costs of alternative energy systems, e.g., diesel-driven irrigation pumps and milling and processing equipment, kerosene for lighting, etc.
5. Comparative total costs of autogeneration

**E. Public Sector**

1. Price of electricity
2. Per capita revenue of municipal governments
3. Number and size of public schools
4. Types of public water supply (e.g., deep-well pumps)

of income for the commercial, industrial and agricultural sectors. When increasing or decreasing block rates are used for pricing electricity, the marginal price of electricity is the appropriate variable to use. However, residential and small commercial consumers tend to consider their total bill when making consumption decisions which implies that consumption decisions are based on average price of electricity. The demand forecast should therefore take the average price of electricity as an explanatory variable. In the case of larger consumers two situations could be relevant. First if they are more likely to use their marginal price then it is the more appropriate variable to include in the demand forecast. Second, larger consumers may face a two-part tariff (demand and energy charges) and therefore they may not know what is the marginal price. The marginal price maybe high or low depending on whether incremental consumption affects the monthly peak demand. In such a situation, an average price may have to be used. The price of the more important substitute fuels should be included in the demand forecast when there are important end-users where significant competition exists between electricity and alternative fuels.

31. Electricity demand in a given period depends on appliances owned in that period. Appliances are durable and the appliance stock is influenced by economic conditions prevailing in earlier years. Therefore, electricity demand at a point of time is affected by economic conditions that occurred earlier. It takes time for consumers to adjust their electricity demand to new circumstances. Relating electricity demand in one period to what happened in an earlier period introduces an element of dynamics. The nature of response of electricity demand to a change in explanatory variable will depend on the length of time involved. In this context, the concepts of short and long run responses that are related through the notion of the rate of adjustment is relevant. The rate of adjustment is the share of long run response in the level of electricity demand that is achieved in one year. For example, if the long run response of electricity demand to a change in price is 10 per cent and the rate of adjustment is 0.2, then 2 per cent of the change in response in electricity demand will occur in year 1.

32. A convenient way of including these dynamic elements in the demand equation is to employ the partial adjustment model. The assumption is that in any given year consumers have a desired level of electricity demand. The durability of appliances makes it difficult for a consumer to rapidly replace appliance stocks. Hence, only a fraction of the adjustment of electricity demand to the desired level is made in any one year. The partial adjustment model incorporates this idea by adding the lagged dependent variable with electricity demand in the previous year to the other explanatory variables. The fraction of the desired adjustment that a consumer makes in any one year can be determined from the
coefficient associated with the lagged dependent variable in the electricity demand equation.2/

33. Having described the major explanatory variables that should be included in estimating electricity demand forecasts for established markets, the next issue is the econometric technique that would be appropriate in estimating the coefficients of an electricity demand equation. The simplest and most commonly used method is that of ordinary least-squares. However, these estimates would be biased whenever block rate pricing of electricity occurs.3/ In that situation, it could be advisable to use the two stage least squares estimator or the instrumental variable estimator both of which yield unbiased estimates of the demand equation coefficients.4/

34. Given the problems arising from the non-availability of and errors in data, interpreting the results obtained from estimating a demand equation for electricity requires caution. The results relate to the coefficients or elasticities associated with the income, electricity price and substitute fuel prices in the demand equation. Three conditions must be met in judging the reasonableness of the results.5/ First, the elasticities must have the correct sign. Second, the magnitude of the elasticity estimates should be plausible. Insights derived from a variety of empirical studies for developed and developing countries suggest that long run electricity price, income and substitute fuel price elasticities in the range of (0, 1.5), (0, 1.5) and (0, 0.5) respectively are plausible. Third, the relationship among the elasticities should be reasonable. For example, the absolute value of the electricity price elasticity should be greater than the fuel substitute price elasticity. The reason for this is that since the substitute fuel competes with electricity in only some end uses, it is implausible that the cross price elasticity with the substitute would be greater in absolute value than electricity's own price elasticity.


3/ The bias could be removed if the block tariff structure was appropriately specified in the demand function. For example, the tariff of the last block in which consumption occurs would be the appropriate price variable and the estimated coefficient would measure the price effect. Changes in tariffs in the previous blocks result in income effects and maybe measured by restricting the magnitude of these coefficients to that of the income variable.


5/ Westley, op.cit.
35. While the importance of having robust and detailed demand forecasts for power development planning cannot be overemphasized, for some developing countries, data and analytical problems could preclude the availability of reasonably reliable estimates of short and long run elasticities for the major electricity consumer categories: residential, commercial, agricultural and industrial. In these cases, there maybe no alternative but to extrapolate elasticities and rates of adjustment from other developing countries. The criteria used in judging the reasonableness of the results are also helpful in judging the suitability of these "borrowed" elasticities and rates of adjustment. While "borrowing" parameter values, it would be important to use estimates from countries that are at a similar stage of development and with similar structures of composition of domestic product.

36. Turning to new markets, the issues relevant for electricity demand forecasts are significantly different. The major factors of relevance are related to the substitution of alternative forms of energy by electricity. Electricity will, on the one hand, replace existing sources of energy and on the other hand, increase additional consumption or demand for energy. The interfuel substitution, crucial for the electricity demand forecast, should be based on actual behavior of consumers. The major consumer categories in new market could consist of residential, commercial, agricultural and industrial users. In the case of commercial, agricultural and industrial consumers, electricity would be supplied by in-house generators in the without project situation. The introduction of grid or mini-hydro electricity by a public utility will lead to a cheaper source of supply. Hence, the initial demand for electricity from the grid could be viewed as consisting of replacement demand. Lower electricity prices, in addition, will lead to increased demand.

37. In the case of residential consumers in developing countries, the major impact will be switching from kerosene to electric lighting. It is commonly observed that when people switch from kerosene to electricity for lighting, they use lights for longer hours. This happens because electric lighting is not only more convenient than kerosene lighting but more activities are possible under the brighter light produced by electric light bulbs. Frequently, the introduction of electric lighting is accompanied by changes in behavior patterns. The difference in the quality of light results in the demand for electric lighting varying from demand for kerosene lighting. This aspect has to be incorporated in the electricity demand equation for residential consumers in new markets. The starting point for doing so is to measure fuel consumption for comparable households using different fuels and observe the difference in the levels of consumption.

38. Incorporating the fuel switching behavior in estimating energy demand will require a two step procedure. First, household fuel use behavior has to be related to household income and family size, price of fuel and its substitutes and access to alternative fuels. Access to fuel is an important explanatory variable in some developing countries because some fuels may be available in limited quantities at government controlled prices. This procedure should be applied to estimate the demand equation for each fuel and major end use. Second, fuel substitution ratios, like a lighting substitution ratio of the number of kilowatt hours per liter of kerosene, should be estimated. This can be done by introducing dummy variables indicating fuel choice to the demand model described in the first step. The dependent variable, in the second step, is changed to total lighting fuel used and lighting obtained. The fuel substitution ratios are given by the coefficients associated with the dummy variables which indicate whether or not a household uses a particular fuel, except kerosene, for lighting.

39. The point of departure of estimating the demand equation for electricity in new markets for residential consumers is the introduction of the second step. This second step is needed to estimate the amount of electricity required to displace kerosene lighting and the relative change in the amount of light obtained by such a switch. The aspect which should be emphasized is that the parameter values should be obtained from actual behavior of households. For example, if it is found that the lighting substitution ratio is 0.9 kwh of electricity per liter of kerosene, this result is obtained from actual behavior and not from laboratory tests. Similarly, if the coefficient associated with the dummy variable for kerosene implies that households using electricity enjoy about six times as much light as those using kerosene, this result comes from observed behavior in a new market.

40. The estimation of electricity demand equation in new markets poses significant analytical and empirical challenges. Data will need to be obtained from surveys of new markets. Household fuel consumption of electrified and non-electrified regions will be required to estimate the equation in the second step. While the difficulties and costs involved should not be underestimated, the payoffs from such an exercise will be substantial in terms of providing the basis for electricity demand forecasts for new markets. In addition, the parameter values of the electricity kerosene substitution ratio and the ratio of light enjoyed by

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households using electricity and kerosene will be crucial in estimating
the benefits of power sector investment in new markets.

41. The approach described to estimate an electricity demand
equation in new markets explicitly accounts for the possibility of
significant differences in elasticity or response of electricity demand
to changes in explanatory variables between new and established markets.
In new markets, the initial elasticities may be substantially higher than
the load or demand elasticities in established markets. The initial
elasticities relate to the size of the new market when low cost
electricity supply is introduced to an area hitherto supplied by a high
cost energy source like kerosene. These initial responses in elasticities
will not be relevant to forecasting the growth of electricity demand as
the market matures.

42. The discussion on electricity demand forecasts in established
and new markets highlights three major issues. First, there is a need to
establish a set of uniform minimum standards on the quality of data and
analysis in electricity demand studies. Second, an analysis of principal
factors responsible for observed similarities and differences in
coefficients associated with the most important explanatory variables is
crucial. This leads to the third issue of setting guidelines for
extrapolating the results of electricity demand studies to developing
countries where data and analytical constraints preclude such studies.

43. The demand forecasts needed for generation, transmission and
distribution investment are likely to be different. A global demand
forecast is required for generation planning. In contrast, transmission
substations are dispersed widely over a service area and a forecast must
be developed for each of them. Therefore, the demand forecasting needs
for transmission are similar to those for distribution planning which
requires a forecast on the basis of a small geographic area. There are
two differences. The time period for transmission, typically fifteen to
twenty years is greater than the four to eight year period used in
distribution. Second, while modern distribution planning methods work
with up to a hundred thousand very small areas from ten to two hundred
acres in size, transmission planning requires fewer, larger area
forecasts. The behavior of substation load growth over time is likely to
significantly differ from both global system and small area load behavior.
Demand forecasting which provides consistency at the three different
levels of aggregation for generation, transmission and distribution
planning will be necessary.

44. Having described the issues that are important in determining
the demand forecast for electricity, it is useful to now introduce the
concepts of power and energy demands. These concepts are crucial in the
least-cost analysis. The terms demand and load forecast indicate the
magnitude of the requirements of both electrical power and energy. The
kilowatt-hour (kwh) is used as the unit of energy. The rate of energy per
unit of time is called power or capacity and is measured in kilowatts
(kw). Thus, energy in kilowatt-hours is the product of power in kilowatts
and time in hours. The distinction between power and energy is important
because the same amount of energy may be supplied within a small interval of time at a high rate of power flow or over a longer period at a lower level of power flow.

45. The load factor which is the ratio of average to peak demand (kW) over a given interval of time is used to relate power to energy. A load forecast can be made either in terms of peak power or the total energy consumed during a given period, say one year, with the conversion from one unit to the other being made by the relationship kW equals kWh divided by the product of 8760 (365 x 24) hours and the load factor.

46. In the context of determining the load factor, it is useful to introduce the load duration curve for a system in a given year.\textsuperscript{14} The load duration curve plots the hourly capacity (kW) demand of the system against the number of hours of the year during which this level of demand is equaled or exceeded. The peak demand kW occurs only over a short period of time. The average level of kW demand given by the total energy in kilowatt-hours or area under the load duration curve divided by 8760 hours is less than peak demand. Therefore, the load factor is less than unity.

47. The shape and height of the load duration curve are crucial for least-cost investment and operational planning in the power sector. While the shape of the load duration curve is often taken to be exogenously given which implies that the load factor is given, the height of the load duration curve will be determined by the demand forecast for power.

IV. AN OVERVIEW OF LEAST-COST INVESTMENT PROGRAM TO MEET DEMAND FORECAST

48. Least-cost system expansion planning constitutes the core of designing investment programs in the power sector. Sophisticated system planning models that solve the problem of minimizing the cost of supplying a given demand forecast for power and energy at some acceptable level of reliability while maintaining technical and operating requirements have been developed for the power sector.\textsuperscript{15} The optimal size, mix and timing of new investments are determined in this manner and related models also provide for least-cost operation of the system. In principle, the above is a typical exercise in operations research. In practice, the interdependence of an extremely large number of variables which are affected by many uncertainties make the problem very complex and intractable. Consequently, the detailed and simultaneous evaluation of all possible investments in generation, transmission and distribution through a very large simulation and optimization model becomes a utopian concept even in the context of least-cost analysis. For example, it is still not possible to have joint optimization of generation and transmission because of a large number of combinations to be arrived at

\textsuperscript{14} Turvey and Anderson, op.cit.

\textsuperscript{15} Ibid.
and the large number of calculations needed to estimate the operating cost and supply reliability at all network nodes. Therefore, the investment planning problem is broken down into subgroupings differentiated by time and geographic area, global programs versus project analysis; and generation, transmission and distribution.

49. Long term planning which deals with periods that are greater than ten years is concerned with major investment decisions pertaining to the structure of the generation mix and the transmission network. The focus is on large investments which must be installed in a number of years equal to the construction lead times. The system configuration for the following years consists of targets which will be revised as more information becomes available. Medium term planning deals with short lead-time investments from one to nine years covering generation, transmission and distribution. The breakdown in terms of geographic area involves the consideration of transmission and distribution systems after generation is given in terms of generating sizes and locations. Occasionally, the interactions between generation and transmission will be explicitly considered.

50. Within investment planning for generation, transmission and distribution systems, the problem can be approached in terms of (i) global, (ii) simulation and (iii) marginal or project analysis. Global models can give only approximate answers because details of alternative programs, especially of individual projects are too numerous to be considered in a model. Therefore, once an approximate solution has been obtained from a global model, simulation models can be used to sketch alternative possibilities around the global optimum. Marginal or project analysis can then be applied to choose from the simulation possibilities in a manner which will focus on the fine details of individual project selection and design. The importance of this point arises from the fact that given the complexities of the power sector even at the subsystem level, the results from cost minimization must be combined with other insights to design investment planning. In that sense, the global, simulation and project or marginal analysis are complementary in power sector investment planning. These types of analyses need to integrate the design of new investment with the characteristics of the existing capacity.

51. In medium-term investment planning for established markets, expansion planning is significantly influenced by capacity endowments and retirement schedules. The investor's objective is to choose investments which will combine existing with new capacity in a manner which will minimize total discounted system costs associated with generation, transmission and distribution systems. The explicit interaction of new and existing capacity in determining least-cost supply of electricity to

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meet certain demand and reliability levels will play a key role in the discussion to follow.

**Generation**

52. Generation planning and operations consist of two main elements, namely, system planning and operations planning. System planning encompasses all decisions affecting the generation capacity of a system and includes addition of new units, retirement of existing units and changes in reservoir capacity of existing hydro units. Operations planning comprises all decisions related to the operation of an existing or expected generating system and which do not affect the physical capacity of its components. Investment planning in generation capacity must be viewed against this background. In addition, determination of the least-cost investment program should include the search for an optimum operating schedule for each plant program considered.

53. The search for optimum capacities and operating schedules is closely related to how the load duration curve is filled out by each generating plant. The areas sliced out of the load duration curve by each plant will determine the energy delivered by each plant and the total system operating costs. The configuration that minimizes total discounted system costs constitutes the optimal solution. This solution will provide answers to the basic questions in the design of generation systems involving the time, size, type or mix and location of generating plants.

54. A number of sophisticated generation system planning models and techniques have been developed which are based on the principle of minimizing the cost of supplying a given demand forecast at some acceptable levels of reliability. Of these, the Wien Automatic System Planning Package (WASP) has been widely used. A brief description of WASP will highlight the issues involved in least-cost investment planning for generation. WASP determines the optimal expansion plan for a power generating system over a period of up to thirty years within constraints set by the planner. The optimum is evaluated in terms of minimum discounted total costs which include capital investment costs, salvage value of investment costs, fuel costs, inventory costs, non-fuel operation and maintenance costs and cost of energy not served. The constraints would include (i) the relationship between generating capacity, retirements and additions of plants; (ii) installed capacity must meet peak and energy demand; (iii) system configuration must meet certain reliability requirements; and (iv) technical requirements.

55. Given an energy and power demand forecast, WASP uses dynamic programming to determine the series of generating plant additions that

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17/ See Albouy, op.cit., for a survey of these models.

minimize the present value of total capital, operating and unserved energy costs over a defined planning period. A description of the information required to run WASP provides insights into the nature of the cost minimization and its results. The data requirements are as follows:
(i) energy and power demands and the load duration curves for each year;
(ii) existing and already committed generating units, e.g., for thermal plant-minimum and maximum operating level (kW), fuel cost per kwh, operation and maintenance cost per kwh, spinning reserve margin, forced outage rate, maintenance days and retirement date; and for each hydro plant-generating capacity (kW), water inflow rate (kwh per period), minimum outflow rate to meet commitments (kwh per period), reservoir storage capacity (kwh), operation and maintenance cost per kW and retirement date; (iii) new generating units should have some information as in (ii) plus capital costs of each plant. Further, all new hydro plants are divided into user selected groups like short and long term storage and within each group, but the order in which each new hydro project will be added to the system must be specified; (iv) reliability including minimum and maximum acceptable margins, maximum acceptable loss of load probability\textsuperscript{19} and value of energy not served; (v) dispatching in terms of merit order\textsuperscript{20} of thermal plants; and (vi) economic data on shadow prices.

Using this information, WASP simulates alternative investment sequences that meet demand within given reliability standards. For each investment sequence, capital, operating and unserved energy costs are calculated for every year of the chosen planning period. These flows are discounted, and the sequence with the minimum present value of total costs is selected. All costs are expressed in terms of economic opportunity values. This description of least-cost investment planning for generation plants indicates the following. First, apart from system generation, WASP will provide the time profile of output generation of each new investment project. Second, the retirement profile of existing plants and the entrance order of new hydro plants must be specified. Third, in determining the technical requirements, e.g. "tunnel constraint", which specifies the width within which candidate generating units must lie, the planner influences the local optimum that is determined. Local and global optima must be distinguished.\textsuperscript{21} In that sense, a large element of judgment

\textsuperscript{19} The loss of load probability which reflects both plant availability and load pattern provides a quantitative index of reliability.

\textsuperscript{20} Generating plants maybe ranked from the lowest to the highest operating costs. This is called the merit order of operations. Plants lowest on the merit order are operated at base load or full time.

\textsuperscript{21} There could be occasions where the relatively "flat top" nature of the optimum solution may make it difficult to distinguish local from global optimum. What is important is that relatively small differences along the "flat top" may translate into significant differences in investment.
must be combined with the capability of WASP to arrive at the least-cost investment program for generating plants. Fourth, WASP can be run, with alternative demand forecast scenarios to arrive at the long run marginal cost of generation expansion.  

While WASP is a powerful analytical tool for generation planning, it is important to note that it solves a specific cost-minimizing problem for generation which is a subset of a larger set of problems consisting of minimizing the net discounted costs of the power development plans and maximizing net benefits for the whole power sector which includes generation, transmission and distribution. Within the confines of generation planning, marginal or project analysis around the 'local' minimum could be needed to fine tune the choice among alternative designs of investment projects. Thus systems and project analysis in least-cost investment planning for generation are more likely to be complementary rather than competitive. This highlights the case for carefully preparing subproject proposals.

Transmission

The problem of locating generation plants is related to the design of a transmission system. However, because the combined analysis of generation and transmission raises major problems, separate models are generally used for the detailed design of each system. For example, a detailed transmission model would be used to determine the optimal sources of supply for a specified load center. In practice, it could be necessary to iterate between generation and transmission models to determine a mutually consistent plan.

A transmission network has two major functions, namely, transporting power from generation points to load points and interconnecting generators to provide higher levels of reliability. The main network planning functions include: (i) determination of the location of generation capacity increments given by the generation expansion plan; (ii) determination of network reinforcements needed to transfer power from generation to load points; (iii) determination of the network operating cost in terms of losses and transfer constraints preventing dispatch of generation and (iv) determination of the supply reliability at the various load points of the network. These functions need to be fulfilled by technical analysis. For example, steady state performance of a transmission system consists of verifying that the line and transformer design limits are not exceeded under normal operating conditions.

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23/ In practice, the location of generation plans could be predetermined. This is particularly so for hydropower plants. Even in the case of thermal plants, the availability of infrastructure often influences their location.

24/ Aloupy, op.cit.
conditions. Transient performance criteria are more complex and are used to test the power system for stability under various contingency conditions.

60. Investment planning for transmission must be considered within the overall network planning functions which involve solving a dynamic network-type problem. The basic objective of investment planning for transmission is to select the type, timing and location of additional lines that would connect the various generating stations to the different load centers in the least-cost manner while satisfying constraints on load, reliability and technical parameters.

61. Transmission expansion optimization is complicated by three factors: (i) it is highly combinatorial because of the large number of grid reinforcement possibilities; (ii) it is dynamic because of economies of scale associated with discrete reinforcement levels; and (iii) technical constraints which result in an extremely large number of different potential system situations with respect to load and equipment availability. On account of all these factors, transmission expansion planning is undertaken using two categories of models: (i) Technical Analysis Models which include classical AC power flow, short circuit and stability analysis. These models require large amounts of data and computer time and therefore they cannot be applied to all configurations used by the planner; (ii) Planning Oriented Models which are cost minimizing models based on operations research techniques with the aim of determining the least-cost network expansion plan.

62. While the Technical Analysis Models ensure technical feasibility, the Planning Oriented Models search for optimality. In practice, the Planning Oriented Models are used to determine the least-cost optimal solution for a few expansion plans whose technical feasibility is ensured through using the classical network analysis obtained in the Technical Models. This two stage approach is needed to keep the problem tractable.

63. The transmission planning models are not as well developed as the generation planning models and the documentation is also not as elaborate. The following characteristics of the models available are noteworthy: (i) a single level of load (annual peak) is considered in each node; (ii) static cost minimization consisting of determining an ideal target network structure for a particular year on the basis of annualized costs is more usual than dynamic cost minimization; (iii) most models minimize investment cost and cost of losses subject to reliability criteria; (iv) investments are dependent on meeting loads in the case of single or double contingency without overloading the network branches; (v) power flow calculation is sometimes based on the transportation method and this is not always appropriate for electrical networks. DC flow

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25/ See Albouy, op.cit., for a Survey of Transmission Models that are available.
representations have been found to be more accurate and acceptable for long run planning purposes.

64. This description suggests that in practice, investment planning for transmission is influenced more by considerations of technical feasibility than economic cost minimization. The nature of the problem and the complex technical features make economic modelling extremely difficult. Even when cost minimization exercises are undertaken, they are applied to configurations which are technically feasible. In that sense, it could be argued that the role of least-cost analysis in investment planning for transmission is to attempt to solve particular aspects of a problem or approximate the entire problem into a simplified problem which is then fully solved. While not complete, these methods are useful in providing insights for comprehensive investment planning. In this context, it should be noted that applying cost minimizing analysis to particular problems does not guarantee the best overall plan. Cost minimization aids in searching through alternative plans, but if the scope of analysis considers only one aspect of the planning problem, the optimal answer may not be part of the overall plan.

Distribution

65. Unlike planning the generation and transmission systems which are interrelated, a power distribution system serving a localized geographic area or load center can be designed relatively independently. A power distribution system consists of a large number of interconnected units operating together to deliver power to consumers. The system would include a number of substations and radial feeders associated with each substation. A planner faces a number of interrelated decisions in the design of this system. These relate to the determination of the best location and capacity of substations and the feeder network. The combinations to evaluate are enormous. Computerized methods have been developed to determine the optimal size, timing and location of distribution substations and feeders.

66. Distribution planning is both short and long run. Short run distribution planning is feeder oriented and emphasizes various operational objectives like overload relief, power factor corrections, service quality improvement, operational maintenance etc. In contrast, long-run distribution planning emphasizes substation planning and overall feeder configuration. System expansion issues are more appropriately considered in the context of medium-term planning which is about five years for distribution subsystems. Typically, an investment plan will begin with a medium-term demand forecast. The system is optimized for the terminal year to determine future substation additions. This configuration is then used to guide short-run expansion for feeders, substations and distribution equipment requirements.

67. Frequently, distribution planning involves technical feasibility analysis only. Forecast loads are imposed on an existing distribution system at various points of time and the network is systematically strengthened to meet the load forecasts adequately. In this manner, the
location of new substations and primary feeders and the upgrading of existing ones would be established to meet consumer demand within acceptable voltage units under both normal and emergency conditions and also during peak and off peak periods. Since there is a large number of possible configurations, the practice is to analyze a set of representative problems to establish general criteria which can be applied elsewhere.

68. Similar to generation and transmission planning, computer-aided programs are available for distribution investment planning such as Computer-Aided Distribution Planning and Design System (CADPAD) programs for least-cost optimization of radial distribution networks. Constrained Multi-Feeder (CMF) programs for optimizing the configuration of a distribution system by simultaneously analyzing many substations and feeders are also available. A CMF program determines the feeder configuration that minimizes total system costs within specified substation transformer and feeder capacity constraints. The substation transformer constraints would be available from the long run distribution planning exercise.

69. While least-cost analysis for investment planning in distribution systems is theoretically possible, in practice its scope and use has been limited. Technical feasibility analysis in terms of localized power flows play a more important role than economic cost minimization. The extremely complex and technical nature of distribution planning limits the scope for least-cost analysis. Therefore, sophisticated models are not as widely used in the design of distribution systems as they are in the design of generation and transmission systems.

70. The discussion in this section indicates that both engineering and economic principles underly conventional least-cost power systems planning. While the focus of this paper is on economic analysis, a consideration of the engineering and technical factors is useful in terms of getting insights into the nature of the problem, how the problem is addressed and what information is contained in the solution for generation, transmission and distribution system investment planning. For example, if the problem is to increase supply, improve reliability and/or reduce losses, the least-cost analysis will indicate the costs required to meet these objectives. If the approach used for investment planning is in terms of ensuring technical feasibility rather than cost minimization, then the limitations of applying results from cost minimization of illustrative problems to the problem at hand will be known apriori. The information contained in the solution to the minimum cost problem will be crucial in identifying and/or quantifying benefits of the investment program or project under consideration.

V. POWER DEVELOPMENT PLAN

71. The power system consists of generation, transmission and distribution components which are highly interlinked both at a point and
over time. While a full-fledged systems approach incorporating the interrelationships between generation, transmission and distribution to investment planning in the power sector is desirable, it is rarely feasible. The previous section provided a brief overview of the issues and approaches to least-cost investment planning for generation, transmission and distribution subsystems undertaken individually. The aggregate of the timing, size, type and location of investment in each of the subsystems over a planning period will constitute the power development plan for a country. The question that arises is how should a power development plan be interpreted. Clearly, that will depend on the quality and nature of the least-cost analysis underpinning investment planning of the power system or subsystems and the extent to which interrelationships between the subsystems have been taken into consideration. The issue as to how these subsystems are integrated with the system as a whole is important.

72. The interface between operational and investment planning in the power sector provides the backdrop against which the general problem of power development planning can be posed. The problem can be described in terms of targets, constraints and instruments. The targets would include the achievement of certain output, reliability and loss reduction levels at specified points of time. The constraints could be viewed as consisting of the availability of generation, transmission and distribution equipment in a system plus the vector of system performance requirements. The instruments will be the investment package in terms of timing, size, type and location for generation, transmission and distribution components to achieve the targets in a least-cost manner as has already been indicated. The level of sophistication of the least-cost analysis varies widely with generation planning being the most, and distribution planning the least sophisticated. In transmission and distribution planning, the emphasis is largely on technical feasibility.

73. Within subsystem planning of generation, transmission and distribution investment, the engineering or technical solution will provide insights on how instruments and targets are matched. In that sense, the relationship between aggregate investment in a subsystem and targets can be drawn. While explicit least-cost optimization will influence the size, mix and timing of generation plants, this will be less in the cases of transmission and distribution. In short, the rationale for investment in a subsystem in terms of relaxing some constraints to meet certain targets will facilitate the identification and quantification of benefits associated with investment and enhance an understanding of the overall power development plan.

74. An interrelated issue is whether instruments and targets can be matched when one focuses attention on an investment project within a subsystem. For example, is it possible to match investment in a thermal power plant with targets like output, reliability and loss reduction levels for a power utility? The description of least cost investment planning for generation clearly indicates that the solution will provide a time profile of output of the proposed thermal generation plant. By estimating the areas sliced out of the load duration curve, the energy
delivered by the plant, its operating costs and loss reduction can be estimated. Another example is whether it is possible to match investment in a certain component of the subsystem of transmission or distribution investment with an objective or target. If a detailed technical power flow analysis had preceded the inclusion of this component in the subsystems investment plan, then it could be possible to match the instrument or investment with the target. Two observations are relevant. Technical interdependence of components within a subsystem may make it impossible to match instruments with targets. Even when it is possible to match instruments with targets, the choice of instruments would often be determined on the basis of ensuring technical feasibility rather than through a process of least-cost optimization.

75. While the matching of instruments with targets for the investment plan for the generation, transmission and distribution subsystems should emerge from the planning process itself, the same may not be true for individual projects within the investment plans for transmission and distribution subsystems. When matching is possible, an individual investment project can be assessed by itself. When it is not, then it would be important to determine that the individual investment project is an integral part or a least-cost component of the total subsystem investment.

76. Given the long range nature of investment planning in the power sector, a common practice is to focus attention on a time-slice, say the first ten years of a twenty year plan. An implication of this is that the same time slice will be relevant for the generation, transmission and distribution subsystems. The time slice of the power development plan will consist of the aggregate of the time slice of the investment of the subsystems. Going back to the question of the meaning of the statement that an investment project \( x \) is an integral part of the power development plan, the answer would have to begin by identifying the subsystem to which it belongs. At the next stage, it would need to be classified why and how it was chosen to belong to the subsystem expansion plan. This points to the extreme caution that is required for understanding and interpreting a statement that investment project \( x \) is an integral part of the least-cost power development plan. Only in the context of a full fledged systems approach to investment planning will such a statement have an unambiguous meaning. In all other cases, the role of investment project \( x \) in the power development plan would need to be assessed by first examining how and why it was included in the subsystem investment plan and second how the subsystem plan was itself determined in relation to the power development plan.

77. The solutions to the least-cost investment problems of the subsystems are aggregated to determine the power development plan. These solutions will contain a wealth of information, both economic and engineering, which will provide useful inputs for the economic analysis such as (i) investment and operating costs of the subsystem; (ii) output, reliability and loss reduction; and (iii) with and without investment scenarios. To the extent that there has been iteration between the generation and transmission planning models, the usefulness of the
information in assessing the power development plan through economic analysis will be enhanced.

78. Total system costs consist of generation, transmission and distribution costs. The information on the investment and operating costs of the subsystems which emerge from the least-cost analysis can be used to determine the marginal generation, transmission and distribution costs. The marginal capacity costs of generation will include the capital costs of additional generation stations installed to meet increases in peak demand together with fixed operations and maintenance costs. The marginal costs of energy generation will include those costs incurred by the production of incremental units of energy. For example, in a predominantly thermal system, these marginal costs would be dominated by incremental fuel and other variable operating costs required to meet additional energy demand at different times. Marginal capacity costs of transmission and distribution plant and equipment are determined by the maximum demand anticipated to be placed on them.

79. While the information required for estimating marginal costs associated with each of the subsystems will be contained in their respective development plans, it is more difficult to obtain an accurate measure of marginal costs of transmission and distribution than to determine the marginal cost of generation. This is so partly because, in contrast to generation, it is usually not possible to isolate and analyze individual projects which can be viewed as being on the margin in the sense of being determined by incremental demand. This leads to the average incremental costs associated with a program of projects put in place to meet incremental demand than the use of long run marginal costs. As will be seen in the next section, the information on incremental costs for generation, transmission and distribution will be important in the economic analysis.

80. The "with and without" comparison plays an important role in investment planning. In the power sector, the with and without comparisons may not be meaningful in established markets where many areas are highly adapted to service. When this happens, the electric utility may not have the option of rejecting a project since severe rationing and breakdown in service may occur. One way of circumventing this problem is to use alternative electricity demand scenarios in determining alternative power development plans.20/ The implicit assumption is to equate a decrease in demand to the without project situation. In this way, the with and without comparisons get closely interlinked with the estimation of marginal costs.

81. In assessing a power development plan, the information on output, reliability and loss reduction resulting from investment in the subsystems will be the starting point for identifying and quantifying benefits. To the extent that interactions between generation and transmission have been accounted for the usefulness of the information

20/ McKechnie, op.cit.
gathered will increase. The discussion in this section describes how the information contained in the design of a power development plan which is the aggregate of the generation, transmission and distribution investment plans can be used to identify and quantify benefits. In terms of the general framework, current practices in power sector investment planning can be described as ending at the second of the four modules described in Section II. The next section will provide an introduction to issues relevant in the third module which discusses the analysis of benefits.

VI. BENEFIT ANALYSIS

82. Broadly, the major objectives of investment in the power sector are to (i) provide additional supplies of electricity; (ii) ensure cost saving to the power utility; and/or (iii) improve the quality of electricity supply. Investment planning is usually done in terms of minimizing cost to meet these objectives. The fulfillment of these objectives becomes the starting point for the benefit analysis whose major components are the identification, quantification and valuation of benefits. In least-cost analysis, given certain targets (objectives) and constraints (capacity endowments and technical performance requirements), instruments (investment) which result in the attainment of the targets in an optimal manner are determined. The matching of instruments with targets is an important part of benefit analysis and is closely related to the identification and quantification of benefits. In that sense, the problem of benefit allocation is project-oriented. Additional supplies of electricity of a higher quality accrue to consumers who operate in a market setting. Thus, the principles involved in the valuation of benefits accruing from the additionality of electricity supply are market oriented.

83. The starting point of the analysis of benefits in the power sector stems from the consideration that while the principles involved in the valuation of benefits accruing from additionality of electricity supply are market-oriented, the problem of benefit allocation is project-oriented. Before getting into this set of issues, it is useful to highlight the importance of the "with and without" principle.

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84. Project or investment appraisal is concerned with the comparison of two alternative allocation of resources, one with the project and one without. The without project case should refer to the allocation of resources which would occur if the project was not undertaken at the time of consideration. Therefore, postponement of the project is one of the options that may be considered for the without project case. In the with and without project comparison, it is important to distinguish the static from the dynamic analysis. In static analysis, the interrelationship over time is not considered whereas in dynamic analysis it is explicitly taken into account. In the static case, the existing allocation describes the allocation of resources in the without project case. In the dynamic case, it refers to the resource allocation, and energy use in particular, in the absence of the project. The specification of the without project case is of direct relevance in the identification, quantification and valuation of benefits.

85. The specification of a without project case is a difficult problem. In established markets, the power utility may not have the option of rejecting a project as this could cause rationing and breakdown of service leading to a severe disruption of economic activity. It is only in new markets that rejection of a project to provide service is a realistic alternative as the areas under consideration are accustomed to do without the service. As a general principle, the comparison of resource allocation in the with and without project situation should be made on the basis of electricity and energy demand and supply in the two cases. While these comparisons can be made in a variety of ways, two extreme cases are given. First, it can be assumed that without the project, electricity demand would decrease by the increments in electricity supply made possible by the project. Electricity demand is assumed to be supply constrained. The forecast of future electric energy consumption is modified by deducting the increments in electricity consumption resulting from the project. The system peak demand and load duration curve would also be reduced in proportion to the new lower levels of energy consumption. Second, it could be assumed that the forecast demand would be met. The approach now would consist of analyzing the expansion plan of the system without the project under consideration and comparing it with the expansion plan which includes the project. Extreme care in the specification and justification of the assumptions used to distinguish the resource allocation in the with and without project situations is required in project appraisal of power sector investments.

Identification

86. The first step in the identification of benefits is the use of the with and without principle in identifying the net output of a power

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29/ This is a modified procedure from the one described in McKechnie, op.cit. See also G. Westley, "Cost Minimization and Cost-Benefit Analysis of the Proposed Generating Capacity Expansion in the Dominican Republic" (Washington, D.C.: Inter American Development Bank, 1987, Mimeographed).
project. Net output is defined as the goods and services that become available to the economy as a result of the project. If the services physically produced by the project add to the supply in the economy, this additionality of supply is regarded as the net output of the project. On the other hand, if the services produced by the project do not add to the supply in the economy but instead substitute for an alternative source of supply, leaving total energy output constant, then the net output of the project is reflected by the resources released from the alternative source of supply. In this case, from the economy's point of view, the net effect of the project is not the output of the project, since this output would be available in the without project situation. The net benefits of the project are the newly available resources that would be released by the discontinuation of the old, displaced activity. A mix of these two possibilities is commonly encountered in the case of power projects. In the accurate identification of benefits, a project analyst must ascertain whether the physical output of a project adds to supply or substitutes for supply or both. In the first case, the actual physical output of the project is identified as the net output of the project. In the second case, net output of the project is identified as being equal to the resources used in the without project situation to supply the same amount of physical output from an alternative source of supply.

87. A variety of benefits can be identified with investment in a generating plant. First, in the without project situation, older plants which are less efficient could be replaced with the quantity of electricity supplied remaining constant. The benefit which would accrue to the power utility would be in the form of resource cost savings arising out of displacing less efficient plants. Engineering information relevant to the power utility could be used to identify these benefits. In addition to resource cost savings and generating additional supplies of electricity, generating plants can improve the quality of supply which is measured by (i) supply interruptions; (ii) variations in voltage; and (iii) variations in frequency. The improvement in the quality of supply always plays a role in planning power system expansion.30/

88. Like a generation project, a transmission project has to be judged in the context of the system of which it is a part.31/ The without project system will have a certain capability for evacuating the power produced and delivering it to various consuming areas resulting in a particular pattern of generation and area wise supply. The benefit will consist of resource cost savings, additional energy supply and/or improved system reliability. A systems approach is likely to be suitable for analyzing transmission projects. However, when a systems approach is not possible, benefits associated with a transmission project will need to be


identified in terms of the main objectives underlying an investment proposal. These could include\(^{32}\) (i) providing facilities to evacuate power from a new generating station and feed it into the grid; (ii) opening up a new area to supplies from the grid or increase supply capabilities to an already connected area; (iii) providing an alternative route for the transmission of power to a particular area so as to increase security of supply; (iv) interconnecting two grids thereby reducing overall costs of supply; and (v) reducing the costs of transmission, say, by reducing systems losses. In case (i), the benefits of the transmission and generation projects are very closely interlinked and the two should be analyzed together. In (ii), the benefit is the additional grid supply to a particular area. In (iii), the primary benefit is an improvement in reliability. In (iv), the benefit could be a reduction in overall generating costs and possibly an improvement in supply conditions. In (v), the benefit is basically the savings in cost to the utility.

89. Unlike generation and transmission projects, distribution projects which cater to the needs of localized markets can be considered independently of the power system. The likely benefits of a distribution project can be identified on the basis of the primary motivation of the proposal which could consist of the following: (i) providing additional electrical energy to towns or villages; (ii) reducing costs of distribution by cutting down distribution losses; and (iii) improving the quality of supply. While expansion projects could be associated with all three benefits, reinforcement projects could be linked to (ii) and (iii).

90. In addition to new projects considered so far, investment in the power sector could also consist of rehabilitation and replacement projects. No new principles or issues are involved in the identification of benefits of such projects. Projects for the rehabilitation of generating stations have well-defined benefits in terms of resource cost saving and/or higher levels of electricity supply. The benefits from the rehabilitation of transmission and distribution systems often consist of reduction in system losses and improvements in system reliability. In replacement projects, the benefit could consist of annual costs avoided from not operating the existing plant and/or meeting energy demand in those situations where supply may decrease without the project because life of the existing plant is over. From the cost side, the issue of sunk costs needs to be treated with caution while considering rehabilitation projects.

91. Whether a power development plan or an investment component in one of the three subsystems is under consideration, the principles involved in the identification of benefits remain the same. The benefits from investment would consist of resource cost savings, additionality of supply and improved quality of supply. While the first benefit will accrue to the power utility, the others will accrue to the ultimate consumers of electricity. The next step in benefit analysis, is the quantification of benefits.

\(^{32}\) Desai, op.cit.
Quantification

92. The quantification of benefits both at the system and individual project level depends on the nature and quality of subsystem planning at the generation, transmission and distribution levels. The quality of the subsystem analysis will depend on whether interrelations between generation and transmission were accounted for through an iterative process of linking the generation and transmission models and whether explicit optimization or technical feasibility analysis underpinned the subsystem investment planning exercise. The starting point of the quantification of benefits is the solution to the least-cost analysis which minimizes cost subject to satisfying constraints on meeting power and energy demands at specified levels of reliability. The differences in power and energy demands met or reliability levels achieved and resource costs in the with and without project situations constitute the benefits of the investment. These results will be available from the least-cost analysis at the subsystem level.

93. At the outset, the relationship between the quality of least-cost optimization and the nature of quantification possible should be clarified. A full fledged cost minimization at the subsystem level will determine the size, timing, type and location of investment that will meet certain demand and reliability levels. The results of this optimization will lead to the quantification of benefits in terms of resource cost savings, additionality of supplies and improved reliability for the investment packages as a whole at the subsystem level. However, it may or may not be possible to quantify benefits of an investment component within a subsystem. While it may be possible to relate instruments to targets at the subsystem level, it may or may not be possible to do so at the individual project level in which case there will be a problem of benefit assignment to a project.

94. Generation system planning is a sophisticated and well developed subject. The engineering-economic principles underlying conventional least-cost generation planning for investment has been described earlier. The quantification of benefits in terms of determining additional supply, improved reliability and resource cost saving for the subsystem investment program from the solution to the least-cost analysis is straightforward. However, it may not be possible to identify and quantify the impact of investment in one of the generating plants on system reliability. On the other hand, the solution to the subsystem least-cost analysis will provide information which can be used to quantify the resource cost savings and additionality of supply resulting from investment in one of the generating plants contained in the least-cost solution. As described earlier, by estimating the areas sliced out of the load duration curve by each power plant, the energy delivered by it can be quantified. Combined with the information on the systems operating costs, the time profile of the plant's output and the cost of supplying that output can be quantified.

If a cost minimization investment plan is available when the proposed project is being appraised, a dynamic multi-period analysis which takes into account systems interrelationships is possible. The explicit incorporation of time sequencing of projects in a systems investment
program makes the analysis dynamic. The dynamic multi-period analysis will explicitly incorporate the systems impact of a proposed project in determining its net output.

95. A problem that frequently crops up is if a full fledged generation planning model is not available, is it possible to quantify the benefits of a generation project while incorporating the systems impact. The system-wide impact on electricity supply from the introduction of a new plant of \( \Delta X \) kw can be determined through the use of the systemwide load factor. The system load factor, \( f \), is defined as the ratio of average power demand to maximum power demand. If the load factor does not change over time, the additional kwh added by the new plant is \( 8760(f) (\Delta X) \). If \( f \) changes over time the situation is different. Assume that the capacity in period \( t \) is \( X_t \) kw and new capacity with the project is \( (X_t + \Delta X) \). Suppose the load factor changes from \( f_t \) to \( f_{t+1} \). Then the change in kwh of operating capacity with the new plant combined with the change in load factor is \( 8760 ((f_{t+1}) (X_t + \Delta X) - (f_t) (X_t)) \). This basically captures the energy generation difference from \( t \) to \( t+1 \) which can be attributed to the project if that is the only additional project coming in. In this manner, the systemwide change in kwh of operating capacity can be determined with and without the project. For simplicity, it has been assumed that the system reserve and loss factors are zero. A reserve margin is set aside for unforeseeable demand increases, forced plant outages and routine maintenance. The share of energy lost in transmission and distribution determines the system loss factor. In computing the amount of extra electrical energy which an interconnected system can provide as a result of constructing a generating plant, one must distinguish between energy and capacity constrained generating systems.\(^{32}\) In an energy constrained system, the extra electricity that the system can provide as a result of a project is the energy production of the project in isolation minus an allowance for a reserve margin and transmission and distribution losses. In a capacity constrained situation, the additional electricity generated would depend on when the reserve margin is the smallest (critical period) and whether the critical period occurs at the time of peak or non-peak hours.\(^{32}\)

96. Transmission planning involves solving a dynamic network problem whose basic objective is to select the type, timing and location of additional lines that would connect the various generating stations to the different load centers in the least-cost manner subject to meeting requirements involving load, reliability levels and other constraints. Quantification of benefits in terms of additional capacity to transmit electricity, improved reliability and reduction of losses should emerge from the least-cost analysis. The problem arises when investment planning is undertaken on the basis of consistency or technical feasibility rather than explicit optimization. Now the quantification of benefits would need to be done on the basis of the constraints in the transmission system that

\(^{32}\) Westley, op.cit.

\(^{32}\) Ibid.
are relaxed by major investment components. Information from the engineering solution that relaxes power flow constraints and which becomes the rationale for investment in the transmission system would provide the basis for quantification of the benefits.

97. While computerized models have been developed to determine the optimal size, timing and location of distribution substations and feeders in the distribution system, the use of sophisticated models is less in the design of distribution systems than in generation and transmission planning of investment. The quantification of benefits arising from investment in distribution would emerge from the rationale used for undertaking that investment. The sophistication of the planning model would determine the degree of refinement in choosing the investment package to meet the desired objectives but would not influence the choice of the objectives. The extent to which these objectives are met would lead to the quantification of benefits.

98. Clearly, the quantification of benefits in the case of investment in transmission and distribution projects is more complex than in the case of generation projects. The nature and extent of rigor of modelling investment program in transmission and distribution subsystems would determine the rigor with which benefits can be quantified. Even where investment planning is carried out on the basis of purely engineering or technical considerations, the rationale for undertaking the investment provides the basis for quantifying the benefits for the subsystem as a whole.

99. However, unlike in the case of generation projects, it may not always be possible to even quantify the additional supply of electricity that will be ensured by a component of the investment program in transmission and distribution. The complexity of the dynamic network problem makes it difficult to match instruments with targets at a project level.

100. The power development plan is the aggregate of the investment in generation, transmission and distribution. Therefore, the benefits of the power development plan will also be the aggregate of the subsystems. To the extent that the three subsystems are interrelated, there will also be interactions among the benefits from investment in each of the subsystems. Relating the benefits from investment in subsystems to those of a power development plan will be valid when there exists: (i) a generation constraint but no transmission or distribution constraints; (ii) a transmission constraint in the system but no generation or distribution constraints, and (iii) a distribution constraint but no generation or transmission constraints. To the extent that there are constraints in generation, transmission and distribution, the benefits of the power development plan would need to be quantified by accounting for the interrelationships among the main components. At the minimum, the major interrelationships between generation and transmission should be taken into consideration.
101. The discussion on the identification and quantification of benefits has been project or investment oriented. Resource cost savings accruing to the power utility and its measurement will also be project oriented. However, the additional supplies of electricity at higher levels of quality will flow to the ultimate consumers. The valuation of benefits from additional supplies of electricity will be market oriented. This set of issues is considered next.

Valuation

102. The discussion on the identification and quantification of benefits indicates that investment in generation, transmission and distribution projects leads to three main benefits, namely, resource cost savings, additionality of supply and improved quality of supply. The first benefit accrues to the power utility. The latter two benefits accrue to the consumers of electricity. In this sub-section, issues related to valuation of benefits which have already been identified and quantified are considered. Two major topics are taken up - valuation of benefits in market prices and in economic prices. Valuation at market prices indicate consumers' willingness to pay while economic prices adjust for market failure caused by inoptimal government intervention. A commonly accepted methodology adopted in the economic analysis of projects is the use of border price equivalents in valuing costs and benefits.35/

103. Consequently, traded goods which are directly imported or exported or whose domestic sale (purchase) results in goods being exported (imported) by some firm or person are valued at cif/fob prices corrected for transport and distribution costs. For all non-traded goods, economic prices are derived by adjusting the market prices. Two broad adjustments can be identified. First, the impact of domestic distortions arising from market imperfections, government intervention and market failure is removed from the market price. Second, the impact of foreign trade distortions arising from government intervention like the imposition of tariffs and quotas is removed. This procedure for deriving the economic prices of non-traded goods ensures they are also expressed in border price equivalents to make them comparable with the traded goods which are expressed in border prices. The derivation of economic prices from market prices is made through the use of conversion factors which can relate to either groups of commodities or specific commodities. Conversion factors are defined as the ratio of economic to market prices. The general principles for economic analysis discussed above are applicable to the power sector. However, the non-storability of electricity which essentially makes it a non-traded good raises some issues on valuation procedures. Expressing benefits in border price equivalents for an output which is non-traded will call for extreme care in the determination of the appropriate conversion factors. In the case of electricity these will consist of consumption and electricity demand conversion factors.

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104. Resource cost savings to the power utility will need to be valued at border prices. These cost savings could be in the form of reduced generation costs and reduced transmission and/or distribution losses. Information on the marginal costs of generation, transmission and distribution expressed in economic prices can be derived from the least-cost analysis. Since generation equipment and fuel are largely traded, reduced generation costs can be directly valued in border prices. When benefits are in the form of reduced transmission losses, they can be valued at the marginal cost of generation. On the other hand, if the benefit is in the form of reduced distribution losses, these losses should be valued at the marginal cost of generation and transmission.

105. Turning to the valuation of benefits associated with the supply of additional electricity to consumers in a system as a whole or in a specific area, a number of issues need to be considered. The demand forecast which establishes the need for a project or investment program is the key to valuation of additional supplies. As already described earlier, the demand equation for new and established markets could differ significantly. While considering valuation of benefits from additional supplies, two distinctions are useful: marginal versus discrete changes in energy demand and new versus established markets. The concepts of consumer’s and producer’s surplus are important for measurement of benefits associated with discrete changes in energy demand. Furthermore, a distinction needs to be drawn between changes in energy demand which are marginal for all consumers and changes in energy demand which are marginal when measured in terms of total energy being supplied. For example, a change in energy demand for certain consumers may be discrete but appear marginal when considered in terms of the changes in total energy demand being met. In these circumstances, the concepts of consumer’s and producer’s surplus could still be relevant. This discussion indicates the importance of measuring benefits associated with additional electricity supply by disaggregated consumer categories like residential, agricultural, industrial, commercial, etc. The benefits from this additional electricity can be classified to accrue from two sources: (i) new markets where consumers switch from some other source of energy to electricity and (ii) established markets where consumers use additional electricity as a result of this project. It is important to distinguish between new and established markets because the valuation of benefits differ greatly in the two cases. For the new markets two issues are important. First, new market must be defined. Second, the economic benefit accruing to consumers as a result of the project to the new markets needs to be identified. The new market in the static case is defined to include present consumers of energy at a particular site.

106. The inclusion of a time dimension will require a change in the definition of new markets. The new market will now include present consumers of energy at a particular site plus the natural growth of consumption which occurs independently from the project. This new market will be supplied with energy from an alternative source of energy in the

39/ Webb and Pearce, op.cit.
without project situation. The economic benefit to the consumers in this case will result from electricity being supplied to new markets at a lower economic cost than other comparable sources of energy. In the without project situation, consumers in new markets already derive benefits from energy consumption. Thus when consumers switch to electricity as a result of the project, the gross benefits obtained from energy remains unchanged for them. Benefits from additional supply are reflected by the resources released from the displaced energy source. Thus, in new markets, economic benefits from additional supply by the project equal the gross economic cost incurred in the absence of the project in order to supply these markets with energy. For this measure of economic benefits to be appropriate, it should be possible for the alternative method of supplying energy to continue to be utilized in the future in the absence of the project. Alternative energy supplies which are hypothetical and not actually utilized cannot be used as a basis for estimating benefit which is reflected in resources released. In addition to resource cost savings, the introduction of electricity in a new market could result in a qualitative improvement in lifestyle. This could be an important benefit especially in the case of rural electrification.

107. In the valuation of benefits in new markets two factors will be important. First, in determining the resource cost savings, the equivalence between fuel replaced and electricity will need to be estimated. Second, the quality differential, if any, would have to be determined. In the discussion on demand forecast for residential consumers in new markets, it was indicated that the econometric estimation of energy and illumination with alternative fuel choice as one of the explanatory variables would lead to the determination of the kerosene electricity equivalence factor and the change in lighting enjoyed when electricity is introduced. Both parameters will be crucial in estimating resource cost savings and quality improvements or valuation of benefits for residential consumers in new markets. In terms of commercial and industrial consumers in new markets, electricity would usually be supplied by diesel generators in the without project situation. The valuation of resource cost savings in these situations is straightforward.

108. In established markets, the benefits from electricity are reflected by the consumer's willingness to pay (WTP) for additional consumption. In the established market, it is important to distinguish final consumption by domestic or residential consumers from intermediate input demand by industrial and commercial consumers because the valuation of benefits differs. Also, while WTP is the fundamental measure of benefits in established markets, WTP will differ in the cases of final and intermediate input consumers of electricity. For final consumers of electricity consisting of residential or domestic consumers, WTP is

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37/ Owing to the non-availability of data, gross benefits obtained from the switch to electricity in new markets usually have to be assumed to remain unchanged although there are quality improvements.

38/ Desai, op.cit.
equivalent to tariff revenue actually paid by the consumer plus consumer’s surplus. Consumer’s surplus is defined as the difference between the price that consumers are willing to pay for any given quantity and what they actually pay. WTP corresponds to the gross benefits received from consumption of a good or service. Consumer’s surplus and tariff revenue are the means by which the end of identifying and valuing WTP is achieved.

109. Electricity is an important intermediate input in agriculture as well as industry. As an intermediate good, electricity is not demanded for itself but as an input to a production process. It is a derived demand. The gain arising from the use of electricity as an intermediate input is the additional production of goods made possible. Hence the marginal value product curve for electricity in the production of goods is the derived demand curve for electricity. Willingness to pay for electricity as an intermediate input is related to the net value of additional production attributed to additional supply of electricity. Users of electricity will also not be prepared to pay more than the cost of substitute energy sources that have been corrected for convenience since the same benefits can be realized from the substitutes. Thus the upper limit to willingness to pay for electricity supplied to agriculture and industry should be the cost of the substitutes or the net value of increased production whichever is less. The heterogeneity of uses of electricity in agricultural and industrial production gives rise to as many distinct intermediate input demand relations as there are products and technologies available to produce them. Difficulties associated with determining these demand relations have led to measuring benefits for industrial and agricultural producers in terms of cost reduction attributable to the introduction of electricity. The alternative method is conceptually simpler, easier to apply and should yield correct measures as those given by the demand relations. The rationale for equivalence between willingness to pay estimated from derived demand functions and cost reductions derived from cost function changes associated with changes in input prices can be found in the duality relationships associated with production functions. The method actually used to estimate benefits in new markets for industrial and agricultural producers would depend on data availability.

110. In the valuation of benefits from additional supplies in established markets, the importance of having demand equations by consumer categories cannot be overemphasized. Willingness to pay for electricity which is used for purposes of valuation is given by the area under a demand schedule. Thus, the availability of an estimated demand equation becomes the precondition to valuing the willingness to pay for electricity. It is the non-availability of estimated demand equation with

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tariff as an explanatory variables that leads to adhoc valuation procedures for willingness to pay.\textsuperscript{41/}

III. Valuing benefits associated with changes in quality of supply raises significant problems. Quality of supply is measured by (i) the scope and duration of supply interruptions, (ii) variations in voltage; and (iii) variations in frequency. The demand for electricity and hence its benefits are influenced by the level of reliability or quality of supply. Quality improvements would result in decreases in costs associated with supply failure. Direct costs incurred by consumers as a result of supply failure are termed outage costs. For industrial, agricultural and commercial consumers outage costs would include lost value added on foregone production, opportunity cost of factors of production and spoilt products. Consumers often respond to power supply failure by modifying future plans to minimize the outage costs. These are called long term adaptive response costs. Shortage costs are the sum of the adaptive and outage costs.\textsuperscript{42/} Questionnaire approaches can be used to value outage costs in the productive sections of the economy.\textsuperscript{42/} Survey techniques are used to measure willingness to pay by the residential sector for reliability. In addition, wage rates to value leisure time can also be used.\textsuperscript{43/} Long term adaptive responses costs will influence shifts in the demand schedules for electricity. Other things being equal, quality improvement will shift the demand schedule to the right thereby influencing the consumer’s willingness to pay for electricity. While quality improvements play an important role in power sector planning, the difficulties and costs involved in valuing the benefits from improved reliability often lead to the exclusion of this component of benefits from the benefit stream used in the cost-benefit analysis.

112. The discussion so far on valuation has been in terms of market prices. If power projects are to be judged in terms of their contribution to national economic efficiency, then the contributions must be measured by some common denominator, called a numeraire. In this paper the foreign exchange numeraire is used. In established markets, domestic consumers will have to be distinguished from industrial and commercial consumers. In the case of industrial, agricultural and commercial users, the increase in production resulting from the output of the project should be valued in border price equivalent. The resource cost saving for the power utility and new market is the difference between the economic cost of energy in the with and without project situations multiplied by the quantity of energy supplied by the project to the new market. Thus, the valuation of benefits in terms of resource cost saving and net value of

\textsuperscript{41/} Ali, op.cit.


\textsuperscript{43/} Munasinghe, op.cit.

\textsuperscript{44/} Ibid.
industrial, agricultural and commercial producers arising from use of electricity from the project is conceptually straightforward as they can be directly valued in border prices. The valuation of benefits for domestic consumers is more complicated. The willingness to pay by residential or domestic consumers should be decomposed into tariff revenue and consumer's surplus. While the tariff revenue should be adjusted by an electricity demand conversion factor, the consumer's surplus needs to be adjusted by a consumption conversion factor. The electricity demand conversion factor can be greater than one in new markets where subsidized kerosene is displaced by electricity.

VII. COST-BENEFIT ANALYSIS: A SYSTEMS APPROACH

113. The core of power development planning consists of an engineering-economic approach to determine investment choice through least-cost analysis. Conventional least-cost investment planning minimizes an objective function, usually the present value of system costs subject to various constraints, such as meeting targets for load and reliability, and maintaining technical and operating requirements. The solution to the problem will indicate the resource cost savings, the additionality of supply and improvements in the quality of supply resulting from undertaking project investments. These are the benefits of the investment program. The latter two benefits will accrue to residential, commercial, industrial and agricultural consumers whose willingness to pay in the markets will determine the valuation of the output. The issues of established versus new markets and marginal versus discrete changes in demand for electricity will have an important bearing on valuation of output. An issue that has come out clearly in the earlier discussion is that while the principles involved in the valuation of benefits accruing from the additionality of supply are market-oriented, the problem of benefit allocation in terms of identification and quantification of benefits is project-oriented. Having explicitly interlinked the costs of the power development plan with expected benefits, the final issue to be dealt with in this paper is the comparison of benefits with costs. This comparison is feasible only when both the cost and benefit streams associated with the investment program can be identified, quantified and valued. While this is usually feasible for the cost stream, the valuation of benefits may not always be feasible. The purpose of this section is to raise some general issues which are particularly relevant for cost-benefit analysis in the power sector.

114. The most basic rule for accepting a project is that the net present value (NPV) of benefits is positive. NPV is defined as the present value of benefits (PVB) minus present value of costs (PVC). Benefits and costs are defined in terms of the difference between what would occur with and without the project under consideration. If projects are to be ranked, the one with the highest NPV would be the preferred one.

49/ See Ali, op.cit., for a detailed discussion of this set of issues.
provided the scale of alternatives is roughly the same and they are independent. The internal rate of return (IRR) which is defined as the discount rate which reduces the NPV to zero is also used as a project criterion. A project is acceptable if the IRR is greater than the cut-off discount rate.

115. Each of these criteria has its counterpart in the least-cost analysis. The NPV test can be used to derive the least-cost rule. In least-cost analysis the benefit streams are kept equal among the alternatives \((x, y)\) considered, implying that if \(PVC_x\) is greater than \(PVC_y\), then \(NPV_x\) is greater than \(NPV_y\). The project with the lower present value of costs is preferred. This is called the least-cost alternative. The equalizing discount rate which equalizes the two cost streams of two alternative investment projects under consideration can also be used to determine the least-cost alternative. If the equalizing discount rate is higher than the cut-off discount rate, then the alternative with the higher initial costs will be the least-cost option.\(^{40}\) Even if a project is least-cost, it would still be necessary to ensure that its NPV is positive.

116. An extremely useful result that follows from the NPV criterion for power projects is the relationship between electricity tariffs \((t)\) and the IRR. The average long run marginal cost (LRMC) for the system that emerges from the power development plan is provided by the ratio of the PVC to PVO which is the present value of incremental output associated with the investment costs. Assume electricity tariff, \(t\), is equal to LRMC. Now \((t) PVO\) is equal to PVC. \((t) PVO\) is equal to PVB where PVB is the present value of benefits using incremental revenues as a proxy. It clearly follows that if \(t\) is equal to LRMC, NPV is zero and the IRR is equal to the cut-off discount rate \((r)\). If \(t\) is less than the LRMC, the IRR is less than \(r\). Though tariff revenue as a proxy for benefits understates the full benefit of additional supply, the comparison of IRR with \(r\) serves the very useful purpose of indicating whether the average tariff is above or below the optimal LRMC level.\(^{41}\)

117. In the discussion on the net present value criterion for accepting a project, a critical assumption is that the projects are independent. Two projects are independent if (i) it is technically feasible to undertake one project irrespective of whether the other project is undertaken and (ii) the net benefits of one project are not significantly affected by the acceptance or rejection of the other project. Given the intratemporal and intertemporal interdependence of the

\(^{40}\) Ali, Public Investment Criteria: Economic Internal Rate of Return and Equalizing Discount Rate.

\(^{41}\) When the impact of a change in LRMC on tariff is allowed in the analysis and the feedback of the change in tariff on the electricity demand forecast taken into consideration in reestimating the least-cost investment plan, the optimal investment program will have an IRR equal to the cut-off discount rate.
power system, power sector projects may fail both parts of the test. Thus the characteristics of the power sector suggest that a systems approach to investment appraisal is likely to be more suitable than a project's approach. The appropriate comparisons would be among alternative programmes of projects over a specified time horizon rather than among alternative projects. For example, the comparison should be made between alternative combinations or programmes of generation and transmission projects to meet the forecast demand.

118. Project interdependence in the power sector does not cause any problem for the identification, quantification and valuation of benefits. However, it causes major problems of allocating benefits to specific projects. In terms of the earlier discussion, it is no longer possible to match instruments (investments) with targets (benefits). In the extreme case when benefits are truly joint to a number of projects, they cannot be logically allocated to each separate project. The comparison of the total discounted benefits with the total discounted costs of the least-cost set of projects will only be possible for determining the overall viability of the investment programme. A systems approach to cost-benefit analysis becomes inevitable. The IRRs to justify potential investments must be set on a system or programme basis rather than on a project basis.

119. The crucial issue that needs to be addressed is whether a systems approach to investment appraisal makes a project approach superfluous. The answer would depend on the circumstances. The following factors are pertinent: (i) while power systems are interdependent, individual projects could have separable costs and benefits; (ii) an important implication of the interaction of existing with new capacity in the power sector is the role of the binding constraint which impedes powerflows as and when required. For example, if distribution capacity is the binding constraint, then investment in distribution could be linked with benefits after netting out the generation and transmission operating costs; and (iii) power development plans are the aggregate of investment plans of the generation, transmission and distribution systems. Investment in subsystems lead to certain benefits which can be and are quantified. On account of all these factors, some circumstances can arise where a 'partial' appraisal of projects can be made. It would be partial because of difficulties in defining project boundary resulting from omission of interdependence of benefits.

120. The question that can be raised is what can be the potential use of project appraisal which is partial. When establishing the viability

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49/ Webb and Pearce, op. cit.

of a power development plan, the magnitudes of supply responses and demand increments would normally be large and discrete making consumers' and producers' surplus significant. In such a case, it would be useful to rank investment projects since establishing the viability of projects which are at the margin of the investment program would be important for planning. Tests of project acceptability based on marginal costs and benefits will be more stringent than those for the intramarginal investment projects. The identification of the marginal projects would be important for planning.

121. A distinction should be drawn between a system or program approach being adopted because projects are interdependent and a systems approach being adopted because individual projects are not being appraised properly or because benefits are not being estimated for some projects. The difficulties associated with estimating benefits from transmission and distribution projects have already been indicated. These could lead to problems in conducting cost-benefit analysis for investment of such projects. However, each investment plan for a subsystem should be based on some rationale which becomes the basis for determining the benefits of the investment proposed. Allocating benefits to an investment program within a subsystem should be possible.

122. An integrated power development plan will usually have a long run horizon of up to thirty years. While the first ten years of the plan could be firm, the rest would be in the form of a perspective plan which would be firmed up over time. The cost-benefit or economic analysis is often done for the investment projects contained in the time-slice of the first ten years. When the time-slice of a power development plan is under consideration, it is important to know what is meant by it. First, it could refer to the aggregate of the generation, transmission and distribution subsystem investment. The methodology and procedures used to determine the investment plan within each subsystem should be known along with attempts made to take into account the interrelationships. The benefits to the power development plan could be attributed to the aggregate of the subsystem investments. Second, the time-slice may describe investment within a subsystem. Depending on the basis for that investment, benefits could be identified, quantified, valued and attributed to investment in the subsystem. Here a partial appraisal of investment in a subsystem may be possible. Third, an investment component within a subsystem maybe under consideration. In the case of a generation project, its output profile taking into account system interdependencies would generally be available. The project could be justified in two ways. First, it is an integral part of the least-cost generation plan which is itself viable. Second, the project is a least-cost solution and a partial analysis taking into account the major interdependencies indicates that the project itself is economically viable. When investment in the component of a transmission or distribution subsystem is under consideration, estimation of benefits associated with the investment component under consideration may not be possible. The investment component would need to be justified on the basis of it being an integral part of the least-cost investment program for the transmission or distribution subsystem and the investment in the subsystem being
economically viable. Against this background, the importance of the analyst clearly specifying the context and meaning of the power development plan or a component thereof under consideration cannot be overemphasized.

123. The analytically rigorous rationale for conducting cost-benefit or economic analysis using the system time-slice approach rests on project interdependence at the intratemporal and intertemporal levels. Given that least-cost investment planning in the power sector is done separately at the generation, transmission and distribution subsystem levels, the time-slice analysis is particularly applicable at the subsystem level. This happens because intra subsystem interdependencies are specifically taken into consideration in optimization or technical feasibility analysis at the subsystem level during the process of investment planning for generation, transmission and distribution. However, only when inter-subsystem interdependencies are taken into account is the time-slice analysis for the power development plan as a whole meaningful.

124. One implication of using piecemeal cost-minimization at the subsystem level for investment planning is that such optimization does not guarantee that the best overall plan of the system is found. Optimization helps in searching through alternative plans, but if the scope of the analysis is such that it considers only one aspect of the planning problem, the optimal solution determined may not be part of the best overall plan.

125. Given this caveat, the potential of using the results of the cost-benefit analysis undertaken at a subsystem level in analyzing projects within the subsystem is explored. At the subsystem level, only the broad outlines of expansion are determined like type, timing, mix and location of new capacity, contribution of each one to supply and interaction among projects. Most models cannot select the best project design among many mutually exclusive variants. The analysis should be refined at the individual project level. The marginal costs and returns determined at the subsystem level can be used to value costs and benefits at the individual project level. This approach will provide consistency between the individual project and the subsystem. Marginal costs and returns at the subsystem level can be estimated by running the investment model with alternative demand forecasts.

126. Investment planning for generation, transmission and distribution though a very large and complicated simulation and optimization model is a utopian concept which will not be feasible in the foreseeable future. The interdependencies in the power sector call for a systems approach to investment planning. The interrelationship between projects, subsystem and the power development plan can and should be exploited to provide mutual consistency in investment planning in the power sector. In that sense the least-cost investment plans of the subsystems provide the interface between project and aggregate planning. Cost-benefit analysis at project, subsystem and aggregate power development plan levels is complementary and not competitive.
VIII. CONCLUSION

127. The power sector faces major challenges in many developing countries. Financial viability and resource mobilization have emerged as some of the key concerns. Major reforms in policies, institutions and investment programs will need to be instituted to meet the challenges and alleviate the concerns. In particular, electricity tariff and public enterprise reforms are likely to occupy the centerstage in the process of sector adjustment. The interaction of reforms in tariffs, public enterprises and investment programs will influence the extent and efficiency of supply response from the power sector in the next decade. While these interactions are important, the focus of this paper has been on investment in the power sector and its assessment.

128. The rationale for the paper's focus on capacity expansion in the power sector stems from the consideration that investment in power systems are highly capital and import intensive and account for a significant share of public investment in most developing countries. Thus, the efficient use of investible resources in the power sector deserves high priority in the development agenda. While the interaction of investment decision, tariff and demand forecast is explicitly recognized in this paper, the impact of changes in cost structure on tariff is not considered. Throughout the paper electricity tariffs are taken to be exogenously given. The reason for doing so is to focus attention on the economic analysis of investment in the power sector.

129. Investment planning in the power sector can be viewed as a dynamic non-linear programming problem where benefits are maximized subject to meeting certain constraints. An efficient and economically viable power sector investment plan emerges where the interaction of the demand forecast, investment decision and the accompanying long run marginal cost of supply is accounted for explicitly. In practice, power sector investment planning has consisted of determining a least-cost investment program to meet certain load and energy demands at predetermined levels of reliability. By itself, however, least-cost analysis says nothing about the economic merits of an investment program or project since even a least-cost program may have costs that exceed its benefits. Whenever possible, it is necessary to consider whether benefits are adequate. However, the interdependence of power projects may make it difficult to allocate or assign benefits to investment projects. In this case, a system or program approach to cost-benefit analysis becomes inevitable. It would be important to distinguish whether this interdependence refers to the overall power development plan consisting of generation, transmission and distribution or whether it deals with interdependence within a subsystem dealing with generation, transmission or distribution. Alternatively, a distinction should be drawn between inter subsystem interdependence and intra subsystem interdependence.

130. The issue of project interdependence, which makes it difficult to allocate benefits across projects, raises a problem in the financing of investment in power systems. Financing is frequently project related.
A rate of return for a project could be required for taking a decision on financing. In cases where the problem of common benefit makes it difficult to estimate a rate of return for a project which is under consideration for financing, all that can be done would be to establish viability of the system or program investment and ensure that the project constitutes an integral part of the least-cost solution of the system or subsystem under consideration. It would be crucial to explicitly define the system in terms of the power development plan or the generation, transmission and distribution subsystem of which the proposed project is a least-cost solution.

131. While system interdependence may require a program approach to economic analysis, in many cases a partial analysis of projects may still be possible if the subsystem least-cost analysis had been rigorously conducted. For example, in a systems approach to least-cost generation planning, the output profile of a project taking into account project interdependencies would be available. Projects which are at the margin of a power development plan should be identified and if possible modified by such partial economic analysis to improve their economic viability.

132. A major contribution of the paper has been to extend power sector investment planning to encompass cost-benefit analysis by indicating how information available from current practices in investment planning in the power sector can be exploited to conduct rigorous cost-benefit analysis. The interlinkages within the power sector and of the major steps in the economic analysis have been combined to provide the interrelationship between project, subsystem and aggregate investment planning in the power sector. The subsystem planning provides the interface between project and aggregate planning. While a large optimization and simulation model combining generation, transmission and distribution networks is an ideal, it is not attainable. Instead, the procedures suggested in this paper capture some of the more important linkages and provide a second-best and feasible framework for conducting economic analysis of investment in power systems.

133. The scope of the paper was confined to investment in the power sector and its assessment. Tariff and public enterprise reforms which along with investment reform will play a central role in sector adjustment were not discussed. In terms of identifying areas of improvement and further research, there is a need to take a sectoral approach where reforms in tariffs, power utilities and investment program are simultaneously considered.\textsuperscript{50} The timing and sequencing of project and sector adjustment lending should be designed in the context of a sector strategy which is underpinned by rigorous sector analysis. Sector analysis (i) provides a better understanding of development policies and issues; (ii) enables the determination of investment priorities; and (iii)

assess the capacity of principal institutions to implement desired policies, programs and projects. Thus, sector analysis will indicate the basic areas of action for policy improvement, institutional strengthening and more effective investment planning. An integrated approach to investment, policy and institutional reforms presupposes rigorous power sector analysis which would enable the design of a medium term sectoral strategy. Research in this direction is urgently required.