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A Review of World Bank Lending for Electric Power

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More people worldwide have access to electric power — but the overall performance of sector utilities is deteriorating. Bank lending should place greater emphasis on improved economic, financial, and managerial efficiency.

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Energy Development

A review of about 300 power projects financed by the World Bank and IDA between 1965 and 1983 shows a declining trend in sector performance. More people have access to electric power, and more kilowatt hours are generated per capita, but overall sector performance has declined, while the quality of service is poor and shows no signs of improving.

Therefore in its operations, the Bank should put more emphasis on:

- Making energy production and allocation more efficient (supplying electricity at the lowest cost and basing prices on real marginal costs) rather than using the supply of power to meet other goals such as social equity.

- Increasing incentives to make utilities more efficient and productive.

- Encouraging sector restructuring and institutional reform, including greater private participation, to improve the social compact between government, consumers, and the electric utility.

- Evaluating power projects with better understanding of power, energy, sector, and national economic linkages.

- Striking a better investment balance between power generation and distribution.

- Improving the quality of existing services (and reducing losses) through rehabilitation and maintenance — rather than by simply expanding the system.

- Providing service on a priority basis to the productive sectors, such as industry and (when economically justified) agriculture.

- Using more risk and sensitivity analysis, and more scenario-oriented "what-if" treatment of uncertainty in project preparation work rather than at appraisal.

- Setting more realistic targets for physical and financial performance and clearer identification of constraints on meeting those targets.

- Developing a better institutional memory for project data.

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I. EXECUTIVE SUMMARY

1.1 Overview and General Observations

This retrospective study was carried out to review power projects financed by the Bank from 1965 to 1983. The main objectives of the study were to:

(i) assess the performance of power projects and institutions in terms of key physical and financial indicators, and adherence to loan covenants;

(ii) assess sector performance in terms of the increase in access to service, and service price, quality, and cost;

(iii) identify issues and causal factors relating to good or poor performance; and

(iv) determine options and make recommendations to improve project and sector performance.

Project Completion Reports (PCR's) and Project Performance Audit Reports (PPAR's) were the principal sources of data, supplemented by information from Staff Appraisal Reports (SAR's) and other specific Bank documents, where necessary.

Since both the Bank and its borrowers have had many decades of experience in identifying, analyzing and solving power sector problems, it is unlikely that any new investigation would produce hitherto unsuspected or startling conclusions. Also, broad generalizations are difficult to make, particularly across a wide range of developing countries in different regions, and over a long period of time. Nevertheless, this study does present fresh insights concerning the electric sector and a better understanding of several fundamental issues that have emerged recently. It also helps prioritize the key issues, identify causal factors, and determine practical options available to decisionmakers, who wish to improve electric utility performance. Finally, the report is designed to facilitate the proactive use of the retrospective study results, in order to improve the quality of future lending.

A central theme that recurs throughout the analysis is the need for greater efficiency in the power sector. The issue is not that power is unimportant to modern economies, or that this capital intensive sector will not continue to merit significant resources in the future, but rather that developments over the past few years have highlighted the need to improve efficiency in the production and use of electricity. Thus, both governments and donors would be well advised to more carefully scrutinize continued requests for resource flows to the sector, and to actively search for methods of increasing technical, financial and managerial effectiveness.

The results of this study confirm that the developing countries have made significant gains in terms of access to, and per capita consumption of electricity over the last few decades. Other evidence also suggests that in many countries the power sector tends to be better organized and perform better than other sectors of the economy. However, during periods of high growth, power utilities have had to weather oil price increases and high inflation and have been hampered in their efforts to attain financial targets because governments have been slow in responding to changing conditions and in granting tariff increases. The study confirms that both the Bank and its borrowers should take early steps to arrest deteriorating trends, given that power investments absorb as much as half of all public investments in some countries, and often are the cause of severe debt-related and macroeconomic stresses. While Bank staff have frequently diagnosed such problems in the past, recommended remedial measures have been less effective because of over-riding political priorities.

The evidence available tends to confirm that the social compact on which power utilities are based and the assumptions under which they operate within developing economies need to be rescrutinized. Over the past decade, the decline in sector performance has been paralleled by a shift towards large monolithic government-controlled electric utilities. This centralizing trend is based on several reasons, such as: the high growth of the power sector, economies of scale in planning and operations, opportunities for improving coordination and efficiency, reduced reserve margins and reliability gains, the need to undertake larger and longer term investments, and pressures for nationalization and elimination of foreign ownership. Although some of this rationale for concentration is still valid, there is a growing consensus about the urgent need for greater efficiency and organizational reform in the power sector.

While the criteria underlying government policy in the power sector rarely have been spelled out explicitly, several of them nevertheless are discernible. First, most developing countries feel that power is an engine for growth and modernization that should be sustained through centrally directed investments and activity. Second, electric utilities are considered a tool for addressing social equity and employment issues and improving quality of life. Third, the sector is sometimes perceived as a vehicle for raising resources and taxing away surpluses (although significant implementation problems are acknowledged).

Although the availability of electric power has brought many benefits, the scarcity of resources underlines the need to focus attention on sector weaknesses and improve the efficiency of resource use. In some cases the failure of the existing social compact between national governments, power producers and consumers, is not due to shortcomings of the policy criteria themselves, but to the imprecise interpretation and application of these objectives. Thus, the desire for growth and modernization mentioned above has resulted in unquestioned funding of power needs, continuous central government subsidies to the sector, nonoptimal or unbalanced investments, and lack of productive efficiency and incentives to maintain technical and financial discipline. Social equity and employment objectives have led to excessive subsidies to consumers, inefficient pricing, and inadequate resource mobilization. Attempts to tax sector surpluses have created highly skewed price structures, cross subsidies, and incorrect price signals. Altogether, this environment has encouraged a casual attitude towards official interference, resulting in excessive and counterproductive government intervention in nearly every aspect of utility activities.

The foregoing considerations and the desperate circumstances of many developing country power utilities have generated pressures for new approaches. In particular, there appears to be considerable interest in the scope for more decentralization and greater private participation, as one means of improving power utility performance and relieving developing country governments of the crippling economic burden of financing the chronic deficits of these state-owned enterprises. The history of the utility sector in industrialized countries indicates periods of fierce internal debate and introspection, followed by significant policy reforms to adapt to changing external circumstances. The rapidly evolving environment faced by developing country utilities today suggests that it would be both appropriate and healthy to carry out such a self-examination, rather than adhering rigidly to an outdated framework.

In evaluating future options in the power sector, it is useful to recall first principles. Economic efficiency requires both productive and allocative efficiency. The first criterion is met by supplying electricity at least cost (i.e., through efficient investment and operation), and the second requires that price equals marginal cost. A new outlook for the power sector should seek to satisfy these criteria in relation to three factors.

First, conditions within the utility must provide incentives for technical, financial and managerial efficiency. Remedial measures must address a number of problems that have plagued these institutions, including: weak planning, inefficient operation and inadequate maintenance, high technical and non-technical losses, low quality of supply and frequent power failures, inability to raise prices to meet revenue requirements, poor management, excessive staffing and low salaries, poor staff morale and performance, undue government interference, and so on. For many utilities these problems have persisted over time despite efforts to identify and correct the causes through consultant studies and institutional development programs.

Second, the national environment within which the utility functions might be restructured to improve performance. Key aspects to be considered include clear-cut government policy guidelines for utility management, delegation of authority to implement agreed policies and corresponding accountability, a rational regulatory framework, government non-interference in daily sector activities, and reforms in the financial climate and access to capital.

Third, dealing with exogenous factors outside the policymakers' control requires that decisions be made with due allowance for uncertainty. Thus, unpredictable changes in demand forecasts, inflation, exchange rates, interest rates, and fuel prices, require a new mindset and scenario-oriented approach to decisionmaking, that is quite different from the deterministic methods that were more useful in the past. Furthermore, it is becoming increasingly evident that effective policy must be determined by using a holistic framework that fully accounts for key macroeconomic and intersectoral linkages -- an approach that is more comprehensive than the narrower, intrasector analysis used earlier.

1.2 Summary of Specific Findings

Although availability, access to service, and consumption of electricity have increased, the overall quality of supply and degree of losses have remained unsatisfactory despite large power investments. It is not possible to discern a clear-cut trend in the movement of average unit cost over the study period, partly because of data uncertainties caused by inflation and exchange rate fluctuations. However, it is clear that average electricity prices have consistently lagged behind costs, while price-related covenants (that invariably reflect the bare minimum of financial requirements), have frequently been ignored, undermined, or postponed.

The results of this study indicate either stagnation at unsatisfactory levels or a declining trend in overall sector performance. During the past decade fewer key project targets have been achieved than during the 1960's. Time overruns have become more likely and greater in number. Cost overruns have fluctuated, but delays in disbursements have increased steadily. The financial performance of utilities also has been poor as measured by indicators such as the rate of return on revalued assets, self-financing ratio, operating ratio, debt service ratio, and days receivable. Declines in performance over time were already evident well before the first oil crisis took place in 1973-74. Errors in demand forecasting have significantly increased during the study period. Except in supply constrained systems, the overestimation of demand in many countries has encouraged overinvestment and aggravated financial strains.

While some of the major indicators of . ormance have deteriorated, others have shown improvement. For example, most utilities appear to have met institutional development targets over the period. Furthermore, conformity with non-financial covenants, many of which are related to institution building goals, was good. Nevertheless, progress on the organizational front has not been able to reverse the overall performance decline in the sector, probably because the institutional and non-financial targets were too modest or wrongly directed, and any gains were overwhelmed by more important exogenous factors. The implication for future action by the Bank and its borrowers is that preoccupation with covenants and conditionalities in non-critical areas, and satisfaction derived from meeting such targets, should not be allowed to divert attention from more fundamental problems that have led to overall erosion of the sector. These problems can be assessed in terms of specific performance indicators, discussed in the next section.

GLOBAL PERFORMANCE INDICATORS

The study has confirmed the general impression that while access to service has improved in terms of the average kilowatt hours generated per capita and the percentage of population served, the quality of service is poor and has shown no sign of improvement. In many cases, service has deteriorated as utilities place unduly great emphasis on extending supply to new areas, often at the expense of maintaining existing installations and quality of service to existing customers. There is thus evidence of an inefficient and unbalanced use of resources. The high levels of losses and the power outage costs associated with poor service quality all result in economic losses that were not expected at the time of project appraisal, and moreover, could have been avoided.

Access to Service and Investment Patterns

The increased access to service is evidenced by the trend in the average level of per capita generation and installed capacity. These improvements in access have required sustained high rates of investment and expansion in total assets of up to 15% p.a. in many countries, which is rather a remarkable achievement. Data for 51 countries between 1968 and 1982 showed that, on average, generation increased by 7% p.a., from 196 kWh/capita to 529 kWh/capita, and installed capacity increased by nearly 8%. The average growth rate of GDP per capita was almost 2% over the same time period, increasing from US$837 to US$1093 (in 1980 prices).

In over 90% of countries, growth rates of generation and installed capacity per capita were more than double the real growth rate for GDP and in 57% of countries they were more than three times the real growth rate. The average growth rate of connections for 29 projects for which data were available was 9% p.a., or about two and a half times the average population growth rate. Access to electricity also increased considerably faster than the GDP growth rate per capita. Indeed, even in countries where there was little or negative economic growth over the period, the majority had more than a 5% annual growth in generation and better than a 3% annual growth in connections.

Power utilities face a double burden of maintaining service to the rapidly growing number of customers now connected to the network, and further expanding the system. The results of this study raise the fundamental question whether single minded pursuit of rapid and sustained expansion is possible or indeed desirable in view of the difficulty utilities and governments will have in carrying on as in the past. The need for electric power to support economic and industrial growth must be examined in determining the priority for system expansion. The role of demand management and conservation as alternatives to capacity expansion, the availability of substitute energy sources, and both the volume and balance of investments in the power sector must be considered in planning for growth in the system. Finally, the size of a power utility must be determined in relation to the scope of decisionmaking required and the capabilities of management to fulfill their functions efficiently.

Overall investment programs appear to have been carried out as planned, but almost 20% of utilities were forced to reduce their programs because of budget and other constraints or a slowdown in demand. The relative emphasis on expansion at the expense of service quality is indicated by the average composition of projects financed by the Bank. The project mix also reflects a bias towards larger projects with relatively few procurement packages that are easier to supervise. On the basis of the total cost of projects at completion, the overall composition of projects approved during the period 1965-1980 was 58% generation, 22% transmission, 9% distribution, and 11% other components. This mix reveals a relative underfunding of distribution by the Bank, in comparison with the other components of the system. Typically, one might expect about 30% of total investment to be required for adequate distribution facilities. As a result of this underfunding, borrowers have sought other sources or have made piecemeal and often substandard extensions to their distribution networks where most of the losses and bottlenecks occur. Ironically, many developing country power systems suffer from unbalanced investments, with overcapacity in generation coexisting with serious underinvestment in distribution.

Losses and Service Quality

The results of the unbalanced investment in sector development are reflected in the high level of technical losses which until they recently become the focus of systematic Bank attention through ESMAP, had been addressed through ad-hoc components within traditional project loans. High loss levels drive up supply costs and increase the sector's financial burden. They are also indicative of a poor quality of service since substandard distribution networks which lead to losses are also responsible for voltage fluctuations and power outages. Poor quality service can have a high economic cost, since customers will be obliged to retain some alternative energy source or suffer a complete disruption of their activities during power failures. Technical losses also have a direct economic cost since a reduction in losses would, at a minimum, improve the quality of service and possibly permit more load to be served or delay the expansion of generation and transmission facilities. In high loss systems, the outlays required to achieve energy savings are generally very much less than the cost of increasing supply capacity.

There are also considerable non-technical losses in electricity systems. These occur from outright theft and inadequate metering, billing, and collection -- all of which indicate poor management, weak commercial operations, and lack of enforcement or ability to disconnect non-paying users of electricity. Taken all together, total losses showed no particular trend over the last decade, instead but showed wide variation on a regional basis. On average, total network losses were 13%, while a reasonable norm would be less than 8%. By region, loss values ranged from a low of 11% in EMENA, 13% in East Asia, 15% in LAC, 17% in South Asia, to 21% in both East and West Africa. More alarming is the finding that in most cases where losses were over 10% to begin with, the situation between project appraisal and completion either remained unchanged or had worsened, often despite remedial action programs and covenants included within projects.

Among a limited but fairly representative sample of 26 utilities, only 10 (or under 40%) evidenced good supply quality based on their record of load shedding, sudden blackouts, brownouts, and voltage and frequency fluctuations. Even more serious is the finding that about 25% of these 26 power companies continued to have poor service quality after over 10 years (at least three projects) of Bank involvement in the sector. The loss levels also exhibited quite similar characteristics.

Cost of Supply and Prices

The average cost of service based on such financial data as operating costs shows little change during the study period, although inflation and exchange rate changes have made it difficult to make comparisons across countries or over time. The economic costs are likely to be higher because assets have not been revalued in all cases and the opportunity costs of resources tend to be greater than the corresponding market values (e.g., the financial rates of return on assets are low compared with the opportunity cost of capital).

In real terms, tariffs have not kept up with financial costs even in financial terms. The steady deterioration in the average operating ratio over the past two decades from 0.65 in the 1966-73 period to 0.80 during 1980-85, provides supporting, but not necessarily conclusive, evidence. Despite much emphasis by the Bank on economic efficiency pricing, relatively modest progress has been made on a global basis except in the cases of specific countries where marginal cost-based tariff studies have been partially or fully implemented. A lack of data, however, prevents a general comparison of tariffs with marginal costs.

PROJECT PERFORMANCE

The performance of projects can be measured in terms of project delays, costs, disbursements, economic rates of return, demand forecasts, and system losses.

Project Delays

The ability of utilities to implement investment programs and more specifically Bank-financed projects according to schedule did not improve during the 1970s and showed no clear trend in behavior. For projects approved between 1967 and 1978, the average project duration was about 46 months; however, the actual average implementation period was 66 months, or 44% longer than forecast. While some delays might be due to design changes, only 10% of projects were completed within 6 months of the implementation schedule established at appraisal. On a Regional basis, EMENA, LAC, and West Africa had time overruns of 51-59%, while East Asia, and East Africa had overruns of 43% and 53%, respectively. Insufficient data were available to give a reliable estimate for South Asia.

In the Regions there have been some variation in delays in the 1980s, but the overall mean value has changed little. Ongoing projects in LAC have higher delays on average mostly because of a lack of funds or slowdown in demand. The average delay in completion in LAC was 18% during the 1960s, increasing to 52% in the 1970s. West Africa has shown some improvement and there has been an overall consistent performance in E. Asia.

Project Costs

Project costs have shown a mixed pattern, depending in large measure on the Bank's ability to make an adequate provision for inflation.

For projects approved in the period 1967-78 and implemented under inflationary conditions, the average cost overrun was 19% and only 40% of projects were within ±10% of the original estimate. Projects approved prior to 1974 had an average overrun of 49% while those approved after 1974, when sufficient price contingencies were provided, showed a cost underrun. The trend continued in the 1980s as two thirds of the projects had underruns or were within +10% of the cost estimate. Underruns have continued in the 1980s as fierce competition among contractors drove prices below estimates made on the basis of conditions prevailing before the recession.

Disbursements

For 115 projects approved between 1965 and 1979, the mean disbursement period was 69 months, or 3 months longer than the average project duration. Most loans took 60-96 months to disburse and two thirds took more than 72 months. Only about 4% of loans took less than 3 years.

Throughout the disbursement period, cumulative disbursements lagged behind forecast, particularly in the early years. During the 1970s this delay appeared to increase, with average disbursements being only 26% of the forecast amount in the first year. Although the average disbursement rose to 48% in year two, it took about five years on average before disbursements reached 90% of the forecast amount. For long projects, cumulative disbursements tended to remain constant at this level until project completion in years 8-10.

Further delays occurred in the 1980s. A sample of projects implemented during this period showed an increasing delay in disbursements in the first four years. Disbursements in year 2 were 36% compared with 48% for the same period in the 1970s, and in year 3 they were 53% compared with 62% in the previous decade.

Economic Rate of Return (ERR)

It is difficult to ensure comparability with regard to the economic rate of return of projects, because the basis for estimating benefits has not been consistent during the period under review. Earlier projects showed the benefits as being determined by the avoided costs of the next cheapest alternative; nowadays approach is only used only to demonstrate that a particular project is the least cost alternative. Various attempts have been made to calculate consumer surplus but the general approach established since the mid 1970's has been to use tariffs as the minimum estimate of the economic benefits.

Since SARs and audit reports use the same methodology to calculate the ERR, the average ERR at appraisal and completion can be reliably compared. For projects approved between 1967 and 1982, the average ERR estimated at appraisal was 14.6% and was calculated at completion at 11.7%. More projects (42%) had ERRs 3% lower than forecast while 21% of projects had an ERR 3% higher than forecast.

Demand Forecasts

The shortfall in ERR can be partly attributed to over-optimism in load forecasting. During the 1970s there were no serious errors of estimation, since the actual results at completion were only 6% less than forecast. For projects approved in 1978 and later, however, there has been a tendency to overestimate demand by about 20%. This trend has continued into the 1980s as a sample of twenty projects showed actual sales 17% less than forecast. In part, these optimistic load forecasts reflect global energy price increases and recessionary conditions that were more severe than anticipated.

On a Regional basis, South Asia, EMENA, and West Africa showed particular over-optimism in demand forecasting, as actual sales were 23%, 18%, and 17% less than forecast.

System Losses

Energy losses, defined as the difference between the physical quantity sent out from the generators and the amount metered and billed, are probably the single best physical indicator of utility performance. They also provide a measure of service quality, which is invariably poor where technical losses are high. Excessive technical losses may be due to poor network design, construction, or maintenance. Non-technical losses reflect theft and poor metering and billing by the utility. Overall losses are the sum of the two types of losses, and clearly reflect the general performance of the utility and its ability to construct and operate the system according to an acceptable standard, as well as government support for enforcement of sound utility commercial practices or legal penalties, where necessary. For projects approved during 1967-1978, 30% of projects showed total losses at completion greater than 20% of generation, while 13% of projects had losses greater than 30%.

In the 1970s and 1980s greater emphasis has been placed on loss reduction components in a number of projects but there has been no significant improvement. Half of the utilities show the same loss level, and 40% had higher losses at completion than at appraisal. The average loss levels for projects approved in the 1970s were 21% for East and West Africa, 17% for South Asia, 15% for LAC, 13% for East Asia, and 11% for EMENA.

UTILITY FINANCIAL PERFORMANCE

The financial performance of the power sector as a whole has shown considerable deterioration over the period starting before the first oil crisis (1966-73), between the two oil shocks (1974-1979), and from 1980 up to 1985. This trend is based on a joint evaluation of several financial indicators as well as the overall context, rather than changes in individual indices.

In each period, poor performance can be traced to a shortfall in revenues, and to a lesser extent, an increase in costs. This situation has arisen because demand has generally fallen short of the forecast level, tariffs (price/kWh) have been less than required, and losses have been greater than forecast. There is little evidence in the year-to-year behavior of these ratios to suggest that the oil crises of 1973 and 1979 gave an unusual shock to the overall trend. Little change in the general deterioration is evident, although the oil crises undoubtedly worsened the downward trend (even if it did not cause a step change).

The performance of individual projects from appraisal to completion contributes to the overall trend of the sector. This performance can be observed by looking at some of the key utility financial ratios, discussed below.

Operating Ratio

The operating ratio (defined as operating costs before debt service, depreciation and other financing charges, divided by operating revenues), is one of the few ratios for which a higher value could indicate deterioration in financial performance. However, the interpretation of this ratio should be related to generation mix and utility size. The average operating ratio for 97 observations was 0.68 in the period 1966-73, deteriorated to 0.73 during 1974-1979, and further to 0.80 between 1980 and 1985. The average for the entire period was 0.74, taken from 259 observations. Over the project implementation period, two thirds of projects approved in the 1970s showed a 5% or greater increase in the operating ratio and 30% of projects had a 20% or greater increase over the forecast at the time of appraisal. Only 9% of projects showed operating ratios which were lower than forecast, again reflecting the tendency for over-optimism. Bank staff recognized the impact of the oil crises in part using less ambitious estimated values in making forecasts after 1973 and 1979. Projects implemented in the 1980s showed similar results.

During the course of project implementation, there was no change in the operating ratio for 40% of projects, while one third showed a deterioration. Of the 28% of projects with a poor operating ratio at appraisal (greater than 0.80), three quarters did not lead to improvements or showed further deterioration in that ratio, over time.

Rate of Return on Assets

During the 1950s and 1960s, more projects achieved the targeted rates of return than in the 1970s and 1980s. Rates of return started at an average of 9.2% from 1966-1973, dropping to 7.9% from 1974-79, and then declining to 6.0% in 1980-85. The average for 220 observations was 7.9%, indicating that the decline has been uniform and steady throughout the entire period since 1966. This trend is only partly explained by the increasing use of revalued assets in computing the rate of return during recent years.

Over the past two decades there also has been an increasing deviation between the forecast and actual rates of return at project completion. For projects approved between 1968-78, on average 18% of projects met the rate of return forecast, 26% were higher than forecast, and 55% were lower. Of the 55%, 43% were below the target by 3 percentage points or more. On average there was little change in rate of return between project appraisal and completion.

Self Financing Ratio

The calculation of self-financing ratio (SFR) has been very inconsistent in appraisal and audit reports, despite very specific guidelines for this computation in OMS 2.22, and the increasing use of this ratio to establish revenue covenants with Borrowers. At the same time, comparability of the SFR across utilities is complicated by the sensitivity of the estimation formula to the financial system of the utility. Many appraisal reports do not allow for changes in working capital in the calculation of the self-financing ratio and, as a result, this ratio is overstated. In many cases, the self-financing ratio would be negative if the ratio had been correctly calculated and on average would be about one quarter less than the ratio estimated in the SAR.

All self-financing ratios have been recalculated in accordance with OMS 2.2. Within their limited applicability, the results show that the forecasting error was in fact high. About 31% of projects had self-financing ratios more than 20 percentage points lower than forecast at completion. The forecasting error has tended to increase during the 1970s and has shown continued deterioration in the 1980s as a result of both over-optimism and poor performance by the Borrowers. At the same time, the actual values of the self-financing ratio have also worsened over time, starting at an average of 25% in 1966-73 but falling to 17% by 1980-85.

During the 1950s and 1960s, an OED study reported that the self-financing ratio improved on average during the course of project implementation; however, for projects approved during the period 1968-83, there was an average deterioration of 6 percentage points during project implementation. This tendency is particularly problematic since the financing of both the project and the sector investment program is generally expected to be supported by an increasing percentage of internally generated funds. This objective is sought not only in connection with economic pricing and to ensure basic financial soundness of the utility but also as part of the overall macroeconomic objective of using the power tariff to mobilize resources for one of the most capital intensive sectors in any country.

Debt Service Coverage Ratio

The debt service ratio for one third of projects did not meet appraisal forecasts and, of these projects, one half were 100 percentage points lower than forecast. The average debt service coverage ratio was

1.8 for the entire 1966-85 period. This ratio showed a decline, dropping from an average of 2.0 during 1966-73 to 1.6 in the 1980-85 period.

The performance of projects implemented in the 1980s was not significantly different from that of projects implemented in the 1970s. About one quarter of projects showed no improvement in the debt service ratio and 40% stayed about constant during the project period. Moreover, of the 50% of all projects which had a modest poor debt service ratio (less than 2.0) at appraisal, half showed no improvement while one quarter showed further deterioration.

Days Receivable

This ratio is a good indicator of the efficiency of the commercial operations of a utility as it reflects its capability with regard to collection of bills, as well as, in some cases, the ability to disconnect delinquent customers. The general Bank target is about 60 days of accounts receivable. Actual days receivable increased from 77 days during 1966-73 to 108 in the 1970s, and to 112 days in the 1980-85 period. The overall average was 96 days.

Seventy seven percent of projects did not meet the forecast, and three quarters of these showed receivables increasing by 20 days more than forecast. During the course of implementation, there was an improvement for 30% of projects, while for another 30% there was a deterioration, generally by more than 20 days.

Conformity with Covenants

On average, there were approximately seven (financial and non-financial) covenants per project during 1968-83. Conformity with covenants was achieved in about 38% of cases and about 33% more were considered to have had fair compliance. The remaining covenants were considered as being in default with poor or no compliance. However, these results may provide a misleading picture. As described earlier, performance was particularly weak with respect to the more important financial covenants, especially rate of return and days receivable. Compliance was achieved most frequently with soft covenants that typically required the carrying out of a study or consultation with the Bank on particular issues.

Institutional Indicators

Institutional performance over the past two decades was reviewed based on indicators such as the number of consumers per employee, adequacy of maintenance, and general utility efficiency. These indicators showed that institutional performance has stagnated at a relatively unsatisfactory level over the period.

1.3 Conclusion and Recommendations

The findings above clearly indicate that performance during project implementation and for the power sector overall has shown a steady decline over the past few decades. The Bank in part has allowed for poorer performance by reducing the financial targets, increasing the contingencies in cost estimates, and reducing demand forecasts. These allowances have not been sufficient and the forecasts in many cases still may be considered unrealistic.

More alarming from the Bank's longer-term perspective is the deteriorating trend over time. This is because the foundation for sound power sector performance in the last decade could most easily have been laid through earlier lending, when the Bank's contribution to overall national power investments was relatively high. The present and future ability of the Bank to induce favorable changes in developing country power utilities through traditional project lending is a continuing cause for concern, as the Bank's share of total sectoral investment declines.

The present situation is not sustainable in the long run and continued sector growth in many countries will hasten the deterioration rather than lead to improvements. Unless there is an improvement in the quality of service to accompany the expansion of service to new customers, there will be increasing difficulties in persuading customers to pay higher tariffs. Governments are very sensitive to the objections of customers, generally the politically influential urban minorities, who resist paying higher prices for poor service which shows little sign of improvement. The consequences of this vicious cycle are equally clear. Poor service leads to low revenues which leads to insufficient internal cash generation and underfunding of all activities, which means poorer service and a greater reluctance to raise tariffs. To further aggravate the situation, funds available from Government are used to support expansion rather than maintenance or rehabilitation.

Not only is there the negative financial impact of poor project performance but also the negative economic impact of continued deterioration in the power sector. Technical, financial and managerial inefficiencies result in misallocation of scarce resources. There are significant economic losses due to poor quality of service and power outages which in most cases exceed the cost of relatively straightforward remedial measures. Finally, the increasing debt burden of the power sector that must be borne by the economy at large, greatly increases the importance of broad power-energy-macroeconomic analysis. The ability of the Bank to influence policy in developing countries will therefore depend more and more on the skill and credibility with which staff are able to deal with complex issues, especially within the context of policy based lending. Conditionality in project or policy based lending may increase the probability of success, but it is clear that without the active cooperation and conviction of governments, there will be little change in the trend of project performance.

The foregoing discussion argues in favor of putting greater emphasis on efficiency and restructuring issues rather than concentrating on expansion. Greater emphasis needs to be given to improving the quality of service and reducing losses through rehabilitation and reinforcement of power systems. Given the present state of many power utilities, it may not be possible to achieve rehabilitation and service improvements simultaneously with system expansion. Furthermore, in many countries there is a large backlog of maintenance requirements in addition to the need to improve operations. These needs already place a burden on institutions which do not have sufficient qualified manpower to meet the requirements for both expanding the system and operating existing systems.

If system maintenance, rehabilitation, and expansion cannot be sustained according to normal demand growth rates, priorities for the extension of new services will have to be set, particularly if governments are not willing to use price as a tool in managing demand. Emphasis should be placed on serving productive sectors, notably industry and agriculture when economically justified. This approach may well lead to less rural electrification and a slower expansion of supply to domestic customers than would otherwise be planned by governments and utilities.

The Bank's normal criteria for project selection would place greater emphasis on improving service quality than on expansion since the rate of return for rehabilitation projects generally will be much higher than for expansion (given the poor state of many power systems today). The lower unit cost of supply achieved through loss reduction or improved availability of existing equipment would be part of the least cost solution and should be fully exploited before adding more facilities. Expanding service at a time when service quality is poor and deteriorating could lead to a reduced economic rate of return since existing and new customers might suffer increased power outages which have high economic costs.

There is a fundamental need to set more realistic targets. The record suggests that targets have been set to justify projects with little chance that the objectives will be met. If it is apparent that projects would not be justified under the assumption of more realistic forecasts, then there is a further argument for more intensification of existing service since this could improve the overall financial performance as well as the economic rate of return of projects.

We have noted earlier, the need to pay greater attention to the treatment of uncertainty, and scenario-oriented approaches. As part of the forecasting exercise, it is advisable to make greater use of risk analysis particularly in connection with financial projections. Until recently, sensitivity analysis was done only in connection with the economic evaluation but no discussion was required (in the SAR financial analysis) of the impact on project and program financing should revenues be less than forecast or if capital costs for the program as a whole were significantly greater than estimated. However, Bank policy now requires discussion of sensitivity to changes in the market, etc. (OPN 2.02).

The study has also revealed the need for more consideration of projects in a sectoral context. Project audits have by and large concluded that projects have been justified and for the most part have been successful in meeting objectives. Taken as a longer-term trend, however, it is clear that the power sector has been in a state of continuous decline despite remaining probably the best performing of all sectors supported by the Bank. It is recommended, therefore, that PCRs and PPARs look more broadly at sector performance and assess overall performance over a longer time span than the project period. The project should be reviewed in the light of total sector performance and its prospects for the future. The justification of projects depends in large measure on sustaining the sector over the physical life of the assets. For many utilities, this is a questionable prospect given the performance over the past two decades.

Specific recommendations for improving project and sector performance are summarized as follows:

1. systematically examine options for sector restructuring, in order to strengthen market forces, improve the environment in which the utility functions, and increase incentives for enhanced utility efficiency;

2. place greater emphasis on improving productive efficiency, with special reference to maintenance, rehabilitation, and distribution network investments, in order to improve losses and the quality of service: measuring productive efficiency can only be achieved by developing more systematic collection and analysis of performance indicators;

3. strengthen the analysis of power-energy-macroeconomic linkages, and pay more attention to project evaluation in the sectoral and national economic context. In particular, assess the feasibility of the sector investment program and the ability of the sector and government to finance the program;

4. in determining investment and pricing policy, adopt less deterministic analytical approaches that can better account for the uncertainties in the current environment. Also carry out a more in-depth risk and sensitivity analysis of the impact of poor project and sector performance in the form of "what if" questions, as part of the financial evaluation to be undertaken during project preparation and as part of sector work (rather than at appraisal);

5. ensure that sufficient investment planning has been carried out to assess the relative importance of rehabilitation and reinforcement compared with generation and transmission capacity expansion. Maintain a balance in lending to ensure that all parts of the system can be uniformly developed;

6. adopt more realistic targets with respect to physical and especially financial performance, and identify more clearly and specifically the constraints to meeting such targets.

The current study has some implications for the manner in which the Bank conducts its own affairs. Clearly, the capability for continued analysis and policy development, as well as the institutional memory, needs to be strengthened. This study indicates significant scope for improving the organization, presentation, consistency, and general accessibility of project data. Availability of the relevant historical data on a consistent format cross different projects, and over reasonable periods of time, would enable statistical analysis at a much more sophisticated level than has been possible in this study. This is highly desirable, since the Bank would then be in a position to better understand the underlying causal factors that influence project and utility performance. Such information would be invaluable in designing loan covenants, arresting adverse trends at a much earlier stage in the project cycle, and predicting power project and utility performance. While most of the useful information on past and current lending may be ultimately retrievable, the effort is likely to be prohibitively costly. Therefore, it is recommended that while the comprehensive database compiled for this study be further developed, regularly updated, and made readily accessible to other Bank staff, a serious effort be made to also collect and preserve all relevant data, for current and future power sector projects.

Beyond the data collection and organization level, there is a need to build up and maintain a critical mass of staff who can provide intellectual leadership and proactive guidance, by analyzing past information, drawing useful lessons for the future, and developing new and viable policies for future operations. This problem is complicated by the tendency for the deep insights and knowledge that has been acquired by senior staff to vanish with their retirement. At the same time, daily pressures on operational staff act as a deterrent to those who wish to synthesize and preserve some of their valuable experience for the benefit of colleagues. The strengthening of the policy development capability is particularly important, given that Bank lending is presently carried out in an environment of rapid change and many relatively inexperienced operational staff are being called upon to address more and more complex issues, often under severe time and resource constraints.

Beyond the database development mentioned above, it would be useful to develop an agenda of more in-depth follow-up Bank studies in areas such as:

1. Investment planning under uncertain conditions – identify and strengthen analytical tools and approaches to determine robust investment policy decisions in changing external circumstances.

2. Integrated national energy planning and policy analysis – strengthen available analytical tools and practical methodology to study key subsector-sector-macroeconomic links and determine energy strategy, and later apply this approach in selected case studies involving both project and policy based lending.

3. Energy-environmental analysis – develop framework for energy sector policy in relation to environmental and natural resource management based on sound economic principles.

4. Critical review of the Bank's power lending experience over several decades in selected countries.

5. Causal links between the external environment of energy sector institutions and their performance.

6. Identification of specific reasons for declining utility performance and their relative importance.

7. Planned versus actual investment programs and reasons for differences.

8. Comparison of marginal costs of supply and prices.

II. POWER PROJECT AND SECTOR PERFORMANCE

2.1 Introduction

A retrospective study of the power sector has been carried out covering projects financed by the World Bank and IDA between 1965 and 1983. Altogether, the study covered about 300 projects, of which about 85% were completed by the end of 1986. While a few aspects of power project performance have been reviewed from time to time, no comprehensive study of Bank-financed power projects covering the last 20 years had previously been undertaken. However, a large sample of projects implemented between 1950 and 1968 was included in a review of the power sector by OED in 1972.[1] Therefore, a limited review of project and sector performance over the past 30 years has been made possible with the additional data collected for this retrospective study. The source of the data collected has been mostly limited to appraisal and audit reports and existing studies carried out by EGY over the past few years. Details of the source of data and how it was analyzed are included in Annex 1.

Throughout the 1950s and 1960s, power sector lending was primarily confined to countries in Latin America, Asia and European countries, plus a few major hydroelectric projects in smaller countries. Several of these countries have since graduated from Bank lending (for example, Ireland and Singapore), while others have continued to borrow funds for the power sector from the Bank (or IDA) almost continuously over the past thirty years (for example, Brazil, Colombia, India, Pakistan and Turkey). During the 1970s and 1980s, the number of countries borrowing to finance power projects increased significantly and there still continues to be new lower-income countries borrowing from the Bank or IDA for the first time for the power sector (Burma and Burundi). Over the time period covered in this retrospective study, 1965-1983, about 33% of projects approved were for Latin America, 20% for the EMENA regions, 17% for East

1/ "Power Sector Review", Operations Evaluation Department (OED), 1972.

Asia, 12% for South Asia, and 9% and 8% for East and West Africa respectively. The loan and credit amounts were distributed in approximately the same percentages as the number of loans except that West Africa received 4% and East Asia about 22% of total Bank/IDA lending.

The principal objectives of this study are:

(i) to assess power sector performance in terms of the increase in availability and access to service, quality and cost of supply, and price.

(ii) to assess power project performance in terms of key indicators relating to physical implementation and to institutional and financial performance and adherence to loan covenants;

(iii) to identify causal factors which explain the reasons for good or poor performance; and

(iv) to identify options and make recommendations, for improving project and sector performance.

The available data were analyzed to determine if there were any common patterns over time in the performance of projects and the sector or whether there were strong regional differences. The results of the analysis of the data do not by themselves indicate whether poor performance was due to (i) an over optimistic forecast of project performance; (ii) the Borrower failing to implement measures that would have improved project implementation; or (iii) external factors that militated against successful implementation of the project. These points are discussed in more detail in the next chapter.

2.2 Access, Quality and Cost of Service, and Price

An initial objective of this retrospective study is to look at the sector from the point of view of the consumer. Therefore, data were analyzed to determine whether or not people in LDC's are better off than they were before 1965 in terms of access, quality and cost of service, and price paid.

Availability and Access to Electricity

Thirty years ago, the supply of electric power in most developing countries was confined to one or two large cities and the major source of power was small thermal plants. During the past thirty years, however, growth of the sector has been very high and now most major towns and many smaller towns have been supplied with electricity from an integrated network using various kinds of power plants operated and developed as a system. Some countries now serve much of the urban population and have embarked on ambitious rural electrification programs.

Installed capacity increased by 9.7% p.a. between 1968 and 1982 compared to 10.6% p.a. in the 1950s and 1960s. Power generation showed similar growth of 9.6% p.a. between 1968 and 1982, and 11.3% p.a. in the 1950s and 1960s. Growth in the power sector has easily exceeded that of real GDP in most countries and also has been far higher than population growth rates, indicating that overall access to electricity service has been increasing.

Access to service can be measured by several indicators, including (i) generation per capita, which indicates the amount of electricity per capita produced; (ii) installed capacity per capita; and (iii) percent of the population actually connected to the public grid. Data for 51 countries in 1968 and 1982 showed that, on average, generation per capita increased by 7% p.a. and installed capacity by nearly 8% p.a. These growth rates compare very favorably with an average real growth rate of nearly 2% p.a. for per capita GDP over the same time period. In over 90% of countries, per capita generation and installed capacity growth rates were more than double the real growth rate for GDP and in 57% of countries more than three times as high.

Earlier data on the percentage of the population having electricity connections were not readily available, but data for just a sample of projects showed an average growth rate of 9% a year in connections -- about two and a half times the population growth rate. For most countries, the growth rate of connections was higher than the rate of growth of real GDP per capita. Indeed, even in those countries where there was little or negative growth over the period, most of the countries experienced more than a 5% annual growth in generation and more than a 3% annual growth in connections.

Quality of Service and Losses

Quality of service did not become a particular issue in the Bank until the late 1970s when the economic cost of power outages and the cost of losses became increasingly important.[2] Before then, losses were dealt with as a relatively minor aspect in projects. The institution of ESMAP, however, focussed specific attention on the reduction of both technical and non-technical losses. The level of technical losses can serve as a proxy measure for the quality of service which can be described in terms of frequency and duration of outages and voltage and frequency changes. Of course, some technical losses are unavoidable because of the characteristics of the power system. Generally, 6-8% in transmission and distribution losses as a fraction of gross generation is regarded as a good target. Station use at the generators might normally increase losses by a further 1-7%, depending on the type of power plant, ranging from hydroelectric to coal-fired thermal.

Losses over and above the "normal" level for an efficient utility result from technical and non-technical causes. High technical losses are systemic and are a function of overloading. They are symptomatic of poor power network design, construction, and maintenance, all of which lead to a poor service quality. Inadequate generating facilities leading to load shedding, particularly at the time of peak load, will further compound the

2/ M. Munasinghe, The Economics of Power System Reliability and Planning, Johns Hopkins Univ. Press, Baltimore, MD, 1979; and M. Munasinghe and W.G. Scott, Energy Efficiency: Optimization of Electric Power Distribution System Losses, Energy Department Paper No. 6, 1982.

problem of poor service quality quite apart from problems caused by the distribution network. Non-technical causes include the failure of the utility to meter and/or bill consumers and failure to control illegal connections. The latter, of course, only adds to the problem of overloading of the distribution network.

Except for specific studies for some countries, very few projects approved in the 1980s assigned an overall rating of service quality to each utility (on a one-to-five good-to-poor scale).[3] The results indicated that 11 out of 26 utilities had a poor to very poor quality of service, taking into account brownouts, blackouts, voltage fluctuations, and systematic load shedding, while ten utilities provided a good quality of service. Of the 11 utilities with poor service, six were on at least their third Bank-financed power project which means that the Bank had been involved with them for at least ten years, and in some cases, more than fifteen years. Similar findings were obtained for levels of total losses.

For the most part, the available data could not discern technical losses as a percentage of total losses. A review of available ESMAP reports on loss reduction studies reveals a wide range of technical losses, as follows.

	Technical Losses % a/	Non-technical Loss % b/	Total Losses %
Sri Lanka	14	4	18
Panama	17	5	22
Sudan	17	14	31
Bangladesh	14	17	31
Liberia c/	13	22	35
Malaysia (Sabah State)	11	17	28
Ivory Coast	8	4	12

a/ Technical energy loss as a percentage of net generation.
b/ On a base of net generation due to metering and billing errors, theft, and illegal connections.
c/ Increased during period 1982 - 1985.

3/ "Power Sector Performance Review", Energy Department, 1986.

The small sample size makes it difficult to draw firm conclusions; however, it would appear from these results and general experience that a poor quality of service is both a symptom and a cause of poor power project and sector performance. Where the utility is weak, for example, in Sudan, Bangladesh and Liberia, commercial operations and distribution investment and maintenance lag behind demand causing a rise in both non-technical and technical losses. As service quality deteriorates, there is a greater tendency for customers to avoid paying for bad service which in turn reduces funds available to maintain and improve the network. For this reason it is reasonable to use total losses as an indicator of quality of service.

Data available for projects implemented between the late 1960s to and 1980s indicated that there does not appear to have been any improvement in the level of losses over time. The weighted (by amount of generation) average losses as a percent of reported generation were 13%, with a median value at 12.5% for projects approved between 1967-78. Losses at this level would normally be reasonable for a utility involved in distribution activities, but it was often ambiguous as to whether the loss figure included station use or not. It appears that many of the figures given have not included station use so that total losses could be in the 16-18% range. Regardless of the definition used to determine losses, about 30% of cases showed losses greater than 20%, which is definitely excessive; in 13% of cases, losses exceeded 30%. Data for projects implemented in the 1980s indicates an average level of losses of 17%, with about 36% of utilities having losses higher than 20%.

Despite greater emphasis placed by the Bank on loss reduction programs in recent years, it appears that, on average, there has been little improvement in the level of losses during project implementation (an average of 5.5 years). Nearly half of the utilities had the same losses at project completion as at appraisal, and about 30% had lower losses. Of those utilities with losses above 10% at appraisal, 40% had even higher losses than forecast at project completion and 26% were lower than forecast. The two Africa regions had the highest loss levels of 21%, followed by South Asia with 17%, LAC with 15%, East Asia with 13%, and EMENA with 10.5%.

Other indicators of service quality are either not available or require further analysis before any conclusions can be drawn. The need for load shedding because of insufficient generating capacity cannot be inferred directly from the available data, for example, on the basis of system load factor or the ratio of peak demand to installed capacity. Load factors could increase either due to load shedding or changes in demand characteristics. The ratio of peak demand to installed capacity is an indicator of the level of reserve margin available and therefore the ability to meet peak demand with allowance for both scheduled and forced outages. The peak demand to total installed capacity ratio was analyzed using the PPAR basic data sheets and was found to lie in the range of 40-100% at the time of project appraisal. For utilities at the high end of the range, generation additions were clearly required. For utilities with an implied reserve margin of around 50%, it cannot be concluded immediately that there is excess generating capacity because of the varying technical characteristics of the systems. In countries where maintenance is inadequate due to lack of skilled staff and available spares, a higher reserve margin would be required to achieve a reasonable level of service as measured by Loss of Load Probability (LOLP).

The optimum level of LOLP will depend on the economic cost of outages such that more industrialized countries in EMENA, LAC, and increasingly in East Asia Regions would require a lower LOLP and, hence, higher reserve margin. The optimal reserve margin requirement is also a function of the nature of the system, its mix of plant, the seasonal firm power available in hydro based and mixed systems, and the extent of derating of older thermal plants. In short, the optimal reserve margin requirement varies depending on circumstance, so that the maximum peak demand to installed capacity figure would show significant variation before taking into consideration other factors such as lumpiness of investment, the point in the planning cycle such as just before (or after) starting (or completing) a large generating plant, the utility's capacity to carry out the planned investment program, and the ability to forecast peak demand. It is not surprising, therefore, that no trend is evident in the peak demand/installed capacity ratios.

Using overall losses, then, as the sole indicator of quality of service, no significant trend over time can be inferred with regard to the quality of service. For the period 1965-1986, it is concluded that there was no overall improvement in service quality during the project implementation period while for about 30% some improvement occurred and for the remaining 20% of projects an overall deterioration is assumed to have occurred.

Cost of Supply and Price

Various approaches were used in the course of this study to determine the trend of the cost per kWh of electricity over time. Data limitations in terms of the number of valid observations that were available were such that no firm conclusions could be drawn from the cost figures themselves. The wide fluctuations in inflation rates and inconsistencies in exchange rates (which complicated the conversion of costs to a base of constant US dollars) made a comparison among countries and over time unrealistic.

Further attempts were made using national consumer and wholesale price indices to obtain a ratio of cost/kWh at completion to the cost/kWh at appraisal in local currency for each country. Since economic costs were not generally available, financial operating costs were used in their place. From the very limited data available for operating costs at the beginning and end of projects, it would appear that nineteen utilities had lower cost/kWh at project completion than at appraisal in real terms and eight had higher costs (using the wholesale price index as a deflator). These very limited results suggest that over the project implementation period (6.5 years on average) the financial cost of power declined by about 14% in real terms. Several points would modify such a conclusion, however:

(i) assets were not properly revalued by utilities in many cases following currency devaluations and in line with local inflation; thus, average costs at completion are understated;

(ii) depreciation rates allowed by governments often are unrealistically low; therefore, capital costs are understated and the weight of capital cost in the total cost of electricity is also understated; and

(iii) fuel cost increases in many countries were not fully passed on to power utilities in line with international markets (neither have fuel prices been reduced in many cases when internal prices fell).

On the other hand, pronounced economies of scale are evident in some countries (Bangladesh, for example, where growth has been a rapid 12-15% p.a.) and generating units and transmission voltage levels have now reached the level where economies of scale are most pronounced. Because of rapid growth, the increasing percentage of recent plant additions at lower unit cost is now being reflected in the annual operating costs.

Available data on operating ratios (the ratio of operating costs to operating revenues), given in Section 2.7, indicates that revenues have not kept up with costs during the 1970s and 1980s. The overall trend in operating ratio shows an increase on average of about one percentage point a year. This finding is borne out by data from a limited number of projects which indicate that tariffs in real terms decreased over the project period by an average of 12% (using the wholesale price index as a deflator). Average tariffs had decreased for 60% of utilities and increased for only 25%. In most countries, tariffs also declined compared to the average cost of living (using the consumer price index as a deflator) until the late 1970s, when it appears that tariffs started to increase more than the consumer price index. However, more data is required before this finding can be verified.

2.3 Project Composition

In countries where a large percentage of the total population remains unserved, the growth in satisfied demand rises directly with the increase in supply. The constraining factor on the growth of the sector then becomes the sustainable rate of investment and of institutional development. These limitations to sector growth have been evident in countries such as Bangladesh, Sudan, and Nigeria (at least while the oil boom was under way). Because of the supply constraint there is a need to maintain a balance in investments in generation, transmission, and distribution facilities; otherwise service quality will deteriorate as one or other component becomes overloaded.

For projects approved during the 1960 and 1970s, 60-65% of total disbursements were primarily for generation and the remaining percentage for transmission and distribution. There has been a slight shift during the 1980s with generation comprising the major component of about 55% of projects. Nearly half of the projects in the 1950s and 1960s contained hydro components (according to the OED report) but this share dropped during the 1970s and 1980s to about 25-30%. The proportion of hydro components appears to have declined even further during the last two years, 1985 - 1986.

The above project composition suggests that the Bank has not sufficiently supported the investment requirements for distribution since typically 30% of total assets should be for distribution facilities to ensure balanced system investment. This mix, however, reflects the Bank's traditional role as the financier of projects which must be completed en bloc (such as hydro and large thermal plants and major transmission lines), rather than the financier of distribution facilities (which can be executed as a continuous series of small projects). Such small projects can be financed with modest amounts of funding from bilaterals, suppliers credits, and the utilities' own resources. This approach has helped to ensure that the large projects have been adequately funded and have generally been well executed; however, it is evident from the poor performance on loss reduction and the need for specific loss reduction programs that there has been a general underfunding of distribution networks with a corresponding poor quality of service. Given the high economic cost of power interruptions associated with distribution faults, there is a strong argument in favor of increasing the Bank's involvement for lending for distribution components and bringing the composition of lending into line with the composition of overall investment requirements.

The Regional share of projects changed quite dramatically from the periods 1950-65 to 1966-83 when many new countries borrowed for the first time from the Bank for power projects. Latin America had received nearly two thirds of the loans between 1950-65 (many of which were for Brazil, Mexico and Colombia) but the region's share dropped to about one third from 1966-83.

2.4 Project Implementation

The performance of projects was analyzed to assess the extent of project delays and cost overruns or underruns, and the rate of loan disbursements.

Project Delays

One of the principal measures of project performance is the degree to which the project was implemented as planned. For the sample of 50 projects implemented from 1967-82, only about 60% were completed as agreed at appraisal. However, in most cases transmission and distribution components were changed since these components could not be precisely defined at the time of appraisal. No clear pattern of revisions emerges, for as many transmission and distribution components were expanded as were only partially completed in comparison with the originally agreed programs.

Adherence to the project implementation schedule is the second key measure of project performance. This also can be an important indicator of the efficiency of the Borrower, although external circumstances outside of the control of the utility do account for many delays (see Chapter III.). On average, projects approved between 1967-1978 were estimated at appraisal to be completed in 46 months but actual implementation time amounted to 66 months -- an average delay of 20 months. About 10% of projects were completed over an exceptionally long implementation period of 90-114 months (Figure 1). Excluding those projects with exceptionally long implementation periods, the average delay was 16 months. Only 20% of projects were completed within six months of the expected time: over 60% were completed one year later than forecast and nearly 30% of projects two years later than expected. As shown in Figure 1, in percentage terms 60% of projects had overruns of more than 30% of the original estimated time and 38% had overruns of 50% or more. Twenty percent of projects were forecast to be completed within 36 months of Board approval, but only 5% actually were. Overall, the average time overrun was 44% of the original estimate.

A breakdown of project delays by component for a sample of projects approved between 1967-78 indicates that distribution components had the longest delays, averaging 22 months, followed by transmission components with an average delay of 18 months. This finding is not altogether surprising considering that transmission and distribution are the components most frequently subject to change. Hydro components had the lowest average delay of 10 months, followed by thermal stations with 14 months. However, the average delay for hydro projects disguises the very high time overruns on some hydro projects because of geological difficulties encountered during construction. For over half of the generation projects included in the sample a substantial portion of time overruns was due to delays in complementary transmission (and to a lesser extent, distribution) components of the project. Smaller components of projects such as training and studies did not account for any significant delays in the sample. On a Regional basis, EMENA, LAC, and West Africa had time overruns of 51-59%, while East Asia, and East Africa had overruns of 43% and 53%, respectively. Insufficient data were available to give a reliable estimate for South Asia.

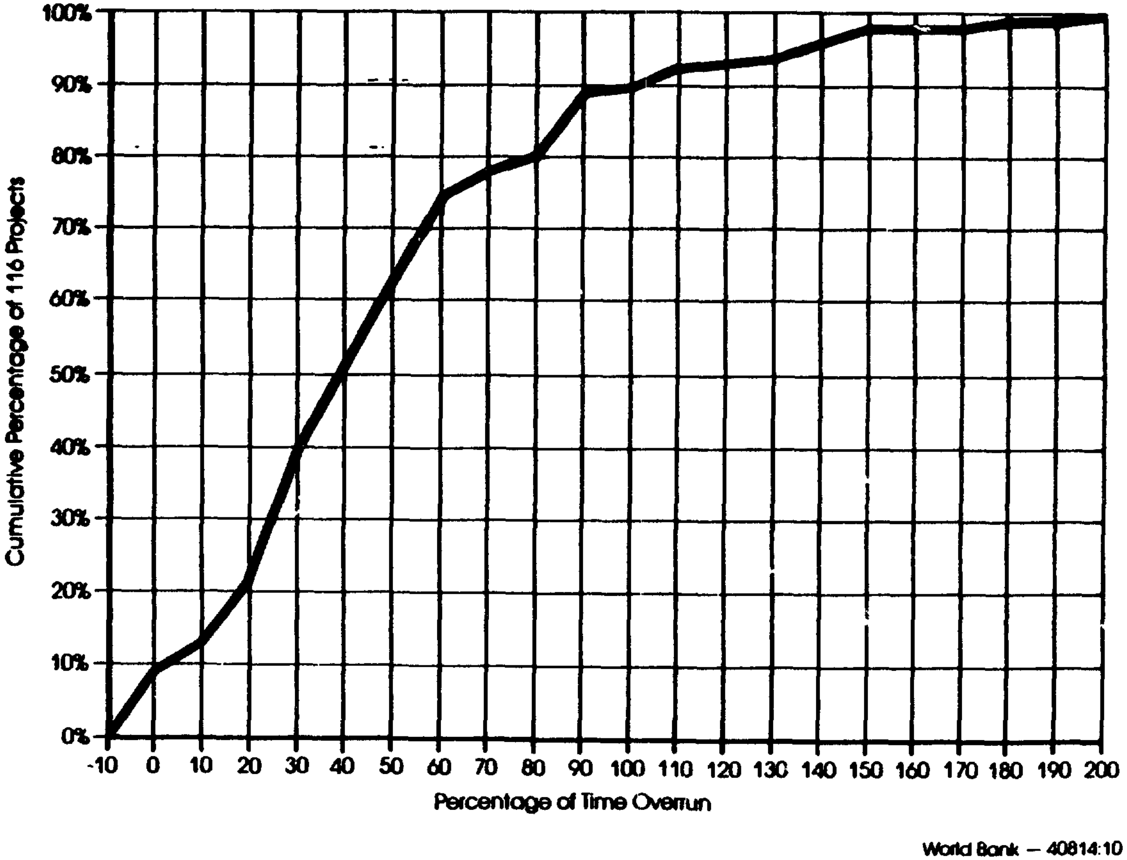

Figure 1: Implementation of Projects.

There have been some variations in delays in the 1980s on a Regional basis, but little change in the overall mean value. Ongoing projects in LAC have higher delays on average, mostly because of a lack of funds or slowdown in demand. The average delay in completion in LAC was 18% during the 1960s, increasing to 52% in the 1970s. West Africa has shown some improvement and there has been an overall consistent performance in East Asia.

Project Costs

The extent to which projects were completed within the cost estimated at appraisal is the third key indicator of performance. Given that many project components are revised during implementation of the project (see Section 3.1), cost comparisons are often difficult to make. Transmission and distribution programs pose a special problem because they are often revised according to whether there are cost overruns or underruns. Therefore, there may be no apparent change in total project costs because substantial cost savings or overruns could have been masked by the project being scaled up or down accordingly. Such hidden factors have to be borne in mind when making cost comparisons between appraisal and completion.

For those projects approved between 1967-78 and completed by 1986, there was an average cost overrun of 19%. About 18% of projects had cost overruns of more than 50% (Figure 2) and another 28% had overruns of 20-50%. Only 40% of projects were either less than or within +10% of the original cost estimate and, of this, 12% were more than 10% below estimated costs. An analysis of the trend over time shows that cost overruns were particularly high for those projects approved before 1974: as shown in Figure 3, the average cost overrun drops sharply from 1974 onwards and there is a significant difference between the averages for the two periods. Those projects approved before 1974 had an average cost overrun of 49% while those approved from 1974 onwards actually had a cost underrun. An analysis of costs of projects approved in the 1980s indicates that on average there has continued to be a trend of cost underruns. About two thirds of projects either had cost underruns or were within +10% of the estimated cost, a finding supported by the analysis of 1984 supervision reports carried out by the Energy Department. More projects approved in the 1980s had substantial cost underruns than those approved in the second half of the 1970s because of the world recession during the early 1980s. Both international and local competitive bids came in lower than expected because of fierce competition among contractors.

The above results indicate that projects approved before and completed after the 1973 oil crisis were subject to serious cost overruns largely due to the completely unanticipated inflation, particularly since some projects approved in the late 1960s did not have a provision for price contingencies in the cost estimates. However, it appears that once Bank staff had adjusted to the new inflationary conditions, actual project costs were more in line with estimated costs. Apart from those projects implemented during the oil crisis, the level of cost overruns appears to have been reduced in the 1970s and 1980s compared with those in the 1950s and 1960s. Available cost data in the OED survey (which is given for each project component, not for the project as a whole) indicates an average cost overrun of 13% compared to a negligible overrun for projects approved for the decade from 1974. A significant part of these cost overruns were for power projects in Mexico which had very high local cost overruns -- these overruns were especially significant because local costs made up 80% of total costs, a far higher proportion than for other countries.

An analysis of cost overruns by region shows that those for Latin American countries have increased over time. During the 1950s and 1960s, average cost overruns were 18% compared with 42% for projects approved after 1967. LAC had the highest cost overruns for projects approved between 1967-78, as shown in the table below. Even with the 1973 oil crisis, South Asia and EMENA had cost underruns on average, while East Asia kept to within +10% of estimated project costs.

Region	EAP	WAP	ASP	AEP	LCP	EMP
Percent Overruns	18.6	16.8	-8.4	9.3	42.4	-9.3

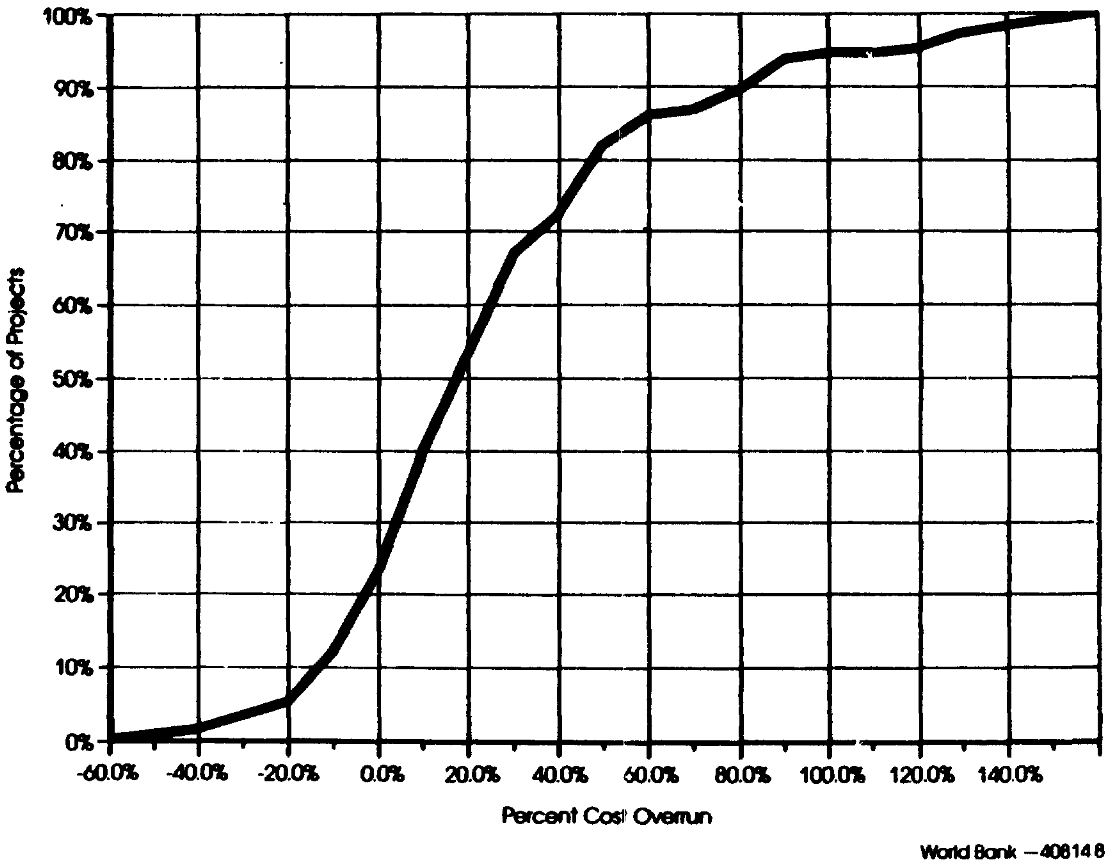

Figure 2: Percentage of Cost Overruns.

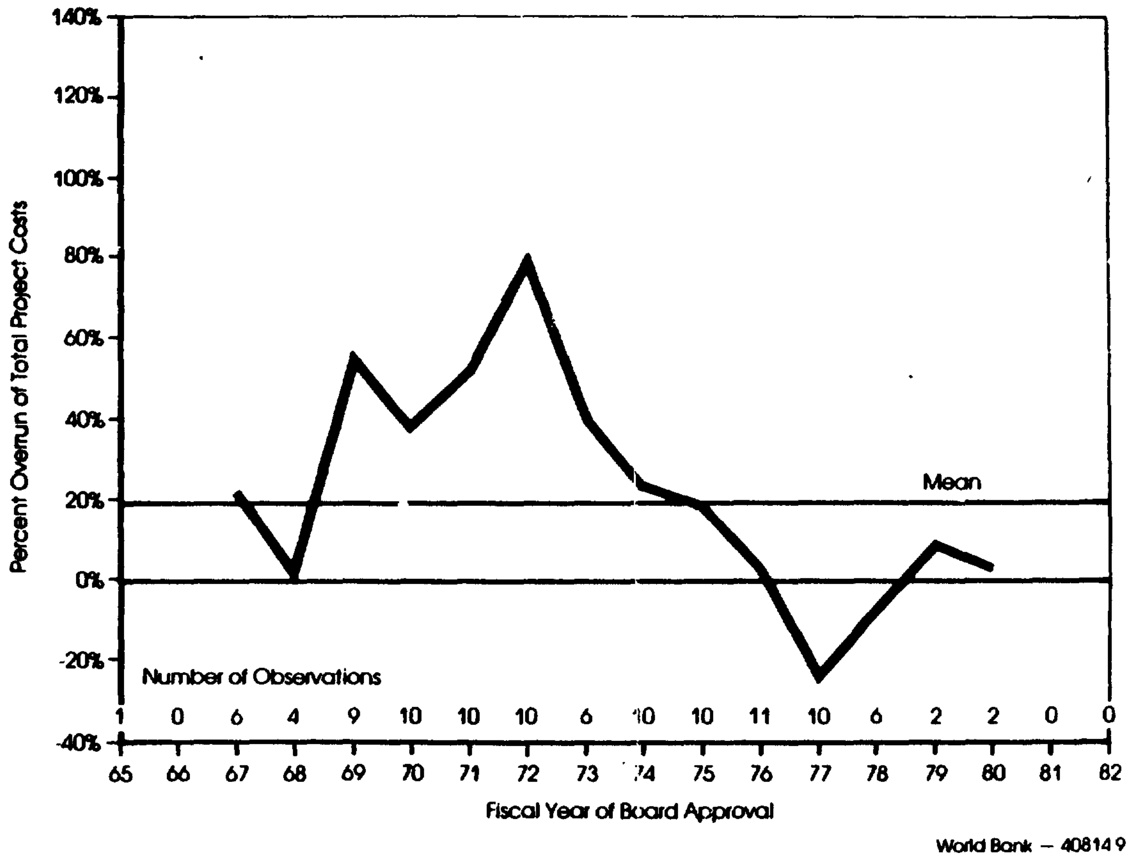

Figure 3: Trend of Percentage Cost Overruns.

The highest cost overruns broken down by project component were for generation projects, with an average 28% overrun (for projects approved in 1967-78). A detailed study of hydro projects approved in the 1970s showed far higher cost overruns of 40% for hydro components compared to 18% for non-hydro.[4] Transmission and distribution projects incurred lower overruns of 16% and 11%, respectively, but these estimates are not reliable because the quality and extent of technical information available from both Bank reports and utilities do not permit sound conclusions to be drawn about costs. This situation is due in part to the large number and diversity of technical specifications, small-size of equipment, and frequent force account activities involved in transmission and distribution projects, all of which make it difficult to monitor project performance.

One might expect to find a high correlation between the amount of cost and project implementation overruns, given that delays can result in cost increases. However, there appears to be little correlation. This lack of correlation between increased costs and project delays can be partly explained by the fact that delays in project start-up need not affect project costs. Also, projects may be reduced in size so as to avoid total cost overruns.

Disbursements

Taking disbursements from the time of Board approval to the date of the final disbursement, the average period for a loan to be disbursed was 69 months compared to an average implementation period of 66 months. Most loans were disbursed over 5-8 years. Two thirds of the loans were disbursed over six or more years and 10% were disbursed over nine or more years; only 3.5% were disbursed within three years, as shown in Table 1.

4/ Geological Complications and Cost Overruns - A Survey of Bank-financed Hydroelectric Projects, Energy Department Note No. 61, July 1985.

Table 1

Time Elapsed between Board Approval and Final Disbursement

Years of Disbursements	Number of Projects	Percent of Projects	Cumulative Percent
0	0	0.0%	0.0%
1	0	0.0%	0.0%
2	1	0.9%	0.9%
3	3	2.6%	3.5%
4	9	7.8%	11.3%
5	21	18.3%	29.6%
6	26	22.6%	52.2%
7	26	22.6%	74.8%
8	16	13.9%	88.7%
9	6	5.2%	93.9%
10	5	4.3%	98.3%
11	1	0.9%	99.1%
12	1	0.9%	100.0%

115 observations for projects approved 1965 - 1979

A comparison of actual disbursements with that forecast shows that actual disbursements have continually lagged behind those forecast from the 1950s to the 1980s, particularly in the first three years of project implementation. From the limited data available, it appears that the lag has increased over time despite repeated efforts by the Bank to improve forecasts and speed up claims for reimbursement. For projects approved in the late 1960s and 1970s, disbursements were only 26% of that forecast in the first year of the project and 48% in the second year. Disbursements gradually caught up with those forecast from year three to year five. Because some projects require more than five years to complete, the cumulative percentage of total disbursements levels off at about 90% of forecast from years 6-8 and reaches 100% only upon completion of all projects by about year 10. Although a similar pattern was found for projects approved in the 1950s and 1960s, the actual level of disbursements was higher at the different stages of project implementation. This deterioration in the rate of disbursement during the first two years of project implementation appears to have continued for projects approved in the 1980s. Disbursements were only 36% and 53% of forecast in the second and third years of the project, compared with 48% and 53% respectively, in the 1970s.

2.5 Economic Aspects of Project and Sector Performance

Rate of Return on the Project

Comparisons of rates of return on projects over time is difficult since they have not been estimated on a consistent basis. For example, in the early 1970s, financial rates of return were calculated but different methods of estimation were used, particularly to value benefits. Later in the 1970s, economic rates of return were required for projects but these have often not been estimated with consistency, especially concerning the treatment of taxes and duties. The audits have reestimated rates of return on the completed project, supposedly using the same method as at appraisal. However, it was not always readily apparent just how the rate of return had been originally estimated, particularly for the older projects. Therefore, the following results should be interpreted with some caution.

On average, rates of return estimated at appraisal were 14.6% compared to reestimated rates of return at project completion of 11.7%. About 18% of projects had reestimated rates of return that were within one percentage point of those originally estimated and 35% were within three percentage points. More projects had substantially lower rates of return been originally estimated, particularly for the older projects. Therefore, the following results should be interpreted with some caution.

On average, rates of return estimated at appraisal were 14.6% compared to reestimated rates of return at project completion of 11.7%. About 18% of projects had reestimated rates of return that were within one percentage point of those originally estimated and 35% were within three percentage points. More projects had substantially lower rates of return than projects with a higher return - 42% had rates of return three or more percentage points below that originally estimated and 21% had returns higher than estimated by more than three percentage points.

Justification of the Investment Program

During the 1970s, the Bank adopted the criterion that the selected project should be part of the least cost investment program for the power sector. Exceptions were made where there was an urgent requirement for additional generating capability; hence, a project could be selected if it was already prepared and ready for implementation, even though it might not have been part of the least cost program. Usually, most appraisal reports commented on the investment program for the power sector and stated whether or not it had been optimized to minimize cost. Unfortunately, the project audit process does not involve a reevaluation of the total investment program so that there is no information on whether the investment program implemented during the project did in fact turn out to be the least cost program.

The analysis of past investment programs is rarely carried out by the Bank. In addition, very little data is available concerning the amount of the original investment program actually completed by the end of the project or the economic consequences of reductions or expansions of the original program agreed in the loan documents. However, it does appear that the majority of investment programs were completed in the 1970s, but probably with one to two years delay, in line with average delays in project implementation. About 15-20% of utilities had to significantly cut back on their investment programs.

Planning

Lack of planning was cited as a serious problem in several of the audit reports for the projects implemented during the early 1970s. This lack of planning led to uneconomic investments. However, power sector planning has undoubtedly improved over the past twenty to thirty years, as the need for more rigorous planning became apparant once the obvious initial investments had been made. As power systems began to grow, more use was made of discounted cashflow analysis and optimizing techniques to determine the least cost expansion programs. With the increasing uncertainty over oil prices, exchange rates and the effect of highly variable economic conditions on the level of demand, it has become even more important to investigate different scenarios and carry out detailed economic planning of the system, and many Bank projects have financed studies for power system master plans.

However, a problem remains as master plans become outdated and require continual revision on account of rapidly changing conditions. Many utilities still have not developed the capability to undertake detailed planning activities and may often be pressured to opt for projects that may not be optimal because of financing constraints or political pressures. This is frequently the case with hydro projects which are highly visible and are regarded as prestigious projects by Governments.

Tariffs

The overall level and structure of tariffs will be a crucial factor in providing incentives for rational use of electricity and load management. In the 1950s and 1960s, very little attention was paid to the economic aspects of tariff setting and the prevailing assumption was that tariffs should be determined according to global financial criteria. The Bank has supported marginal cost pricing over the last fifteen years and has persuaded a significant number of utilities to set tariffs according to marginal cost pricing criteria so that consumers would be charged the amount which correctly reflected the value of the resources required for power supply.[5]

5/ M. Munasinghe and J.J. Warford, Electricity Pricing, Johns Hopkins Univ. Press, Baltimore, MD, 1982.

By 1982, about 44 efficiency pricing studies had been completed and a further 25 were under way. Some 20 countries had incorporated efficiency pricing principles, either fully or partially, into their tariff structures. However, the spread of efficiency pricing has been slow in some countries, because the concept has been resisted quite strongly on the grounds that electric power is a public service and therefore should be sold at a price sufficient only to recover historical costs.

2.6 Demand Forecasts

Since the energy (GWh) forecast is the starting point for both power system and financial planning, the preparation of a realistic demand forecast is a key element in project success. There is a normal tendency to be optimistic in forecasting sales; hence, one would expect a priori to see a higher proportion of actual sales being less than the forecast value. Surprisingly, on average the overestimation of sales forecasts for projects approved from 1967-78 was comparatively small, i.e., actual sales at project completion were 6.4% lower than forecast for the period as a whole. However, as shown in Figure 4, there has been a definite downward trend in accuracy throughout the 1970s. Prior to 1973, forecasts were, on average, accurate in assessing the actual sales at completion of the project and for projects approved in 1969-70 actual sales at completion were actually higher than estimated at appraisal. This situation was thereafter was reversed as forecasts turned out to be more and more over-optimistic, until for projects approved in 1978 forecasts were on average overestimating sales at project completion by about 20%. This trend has continued for projects approved in the 1980s, with actual sales 17% less than originally forecast.

Close to half the projects approved between 1967-78 overestimated demand by 10% or more (particularly in the post-1973 period), compared to about 70% of projects in the 1980s. About 30% of projects overestimated demand by more than 20% during the 1970s and 1980s. On the other hand, only 13% of projects exceeded the forecast level of sales by more than 10% during both periods. For projects implemented during the 1950s and 1960s, demand estimates generally were more accurate. A survey of 75 Bank loans to 37 countries in the 1950s and 1960s found that, on average, sales forecasts were only 2% more than actual sales, but that with certain loans there was a large discrepancy between the forecast and actual amounts.[6] For projects approved in the 1950s and 1960s, the standard deviation of actual energy sales from that forecast was 38%, which is the same as was found in a similar study by OED.

On a Regional basis, sales for East Asia utilities were almost the same as forecast during the 1970s and for East Africa were only 6% below that forecast. LAC actually exceeded the forecast level of sales by 5%, but has since had considerable overestimates. Other regions showed significant overoptimism by as much as 23% in South Asia, 18% in EMENA, and 17% in West Africa.

2.7 Financial Performance of Power Projects and the Sector

An integral part of any Bank-financed project is to ensure the financial health and stability of the Borrower. The eventual aim is to make the utility financially independent so that it is able to fund a substantial portion of its investment program from internal sources and is sufficiently credit-worthy to raise the remaining funds from commercial sources (both local and foreign). The fundamental financial soundness of a utility can be measured by five key ratios -- (i) rate of return on assets, (ii) operating ratio, (iii) self-financing ratio, (iv) debt service ratio and (v) days receivables. The debt/equity ratio is also an indicator of financial performance where the debt is not owed to government. However, many utilities in developing countries borrow heavily from government, but when in financial straits this debt is often waived, interest payments rescheduled, or the debt converted to equity. Given the problems of definition of debt, revaluation and conversion of debt, and revaluation of assets, it was decided to focus only on one capital structure ratio i.e., debt service coverage.

6/ "Ex-post Evaluation of Electricity Demand Forecasts," Energy Department Note No. 79. June 1975.

The use of various financial ratios to evaluate performance at different times is fraught with difficulties, but in a study of this nature it is not possible to do otherwise. The accounting definitions have changed over time so that the ratios have been calculated on different bases. For example, in some cases the basis for estimating the rate of depreciation of assets has changed, affecting nearly all the financial ratios; the method of estimating the asset base on which the rate of return is calculated has changed; and the treatment of bad debts has changed, affecting the days receivables ratio. Whether the effect of such changes overall cancels out when aggregating the data is not clear. In addition to the definition of financial ratios, there are often many problems with accounting practices in utilities, which leads to under- or over-estimation of many of these ratios.

As shown in Figures 5 to 9, there has been a distinct deterioration in the trend of financial ratios for the period 1968-85. In the case of the operating ratio and days receivables, an upward trend indicates deterioration while for all others a downward trend shows worsening. The deteriorating trend began to appear even before the impact of the first oil crisis in 1973-4 and has worsened steadily thereafter.

Table 2 summarizes the average value for each ratio in the periods in 1968-1973, 1974-1979, and 1980-1985 which correspond to distinct periods surrounding the oil crises. All ratios behave consistently and, given the number of observations in each case, the differences in each period are significant. Outliers relating to particularly unusual circumstances have been removed from the data to avoid bias. The results indicate that many utilities are now in a very poor financial position, for example, an operating ratio of greater than 1.0, a negative rate of return, zero self-financing, and no debt service coverage.

Table 2

Trend of Key Financial Indicators

Financial Ratio a/	1966/73	1974/79	1980/85	Average 1966/85
Operating ratio	0.68	0.73	0.80	0.74
Rate of return	9.2	7.9	6.0	7.9
Days receivable	77	97	112	96
Self-financing ratio	24.6	18.6	17.2	20.1
Debt service ratio	2.0	1.8	1.6	1.8

a/ Financial ratios correspond to actual values at appraisal, completion, or supervision, depending on project status.

According to the OED review in 1972, there were higher rates of return on assets and higher self-financing ratios for utilities in the 1960s. Most rates of return fell within the 8-9% range, compared with the much wider spread in the following twenty years, while self-financing ratios averaged about 30% compared to 20% for the three periods above. Internal cash generation had improved throughout the 1950s and 1960s for six out of the seven entities studied which led OED to conclude that there would be a continual strengthening of utilities' financial situation.

Rate of Return on Assets

The financial rate of return on assets has always been one of the indicators used by the Bank to monitor the financial performance of entities, and there is a widespread practice of using a revenue covenant based on self-financing targets in place of, or in addition to, a rate of return covenant. The rate of return should be reported on a pro forma basis where not formally required by the government and should be calculated on revalued assets. It appears, however that many estimates in appraisal and audit reports (particularly for projects approved in the late 1960s and 1970s) were calculated on an historical value of assets base. Therefore, the comparison of rates of return at project completion with those forecast includes cases where rate of return estimates were based on both revalued and historical assets.

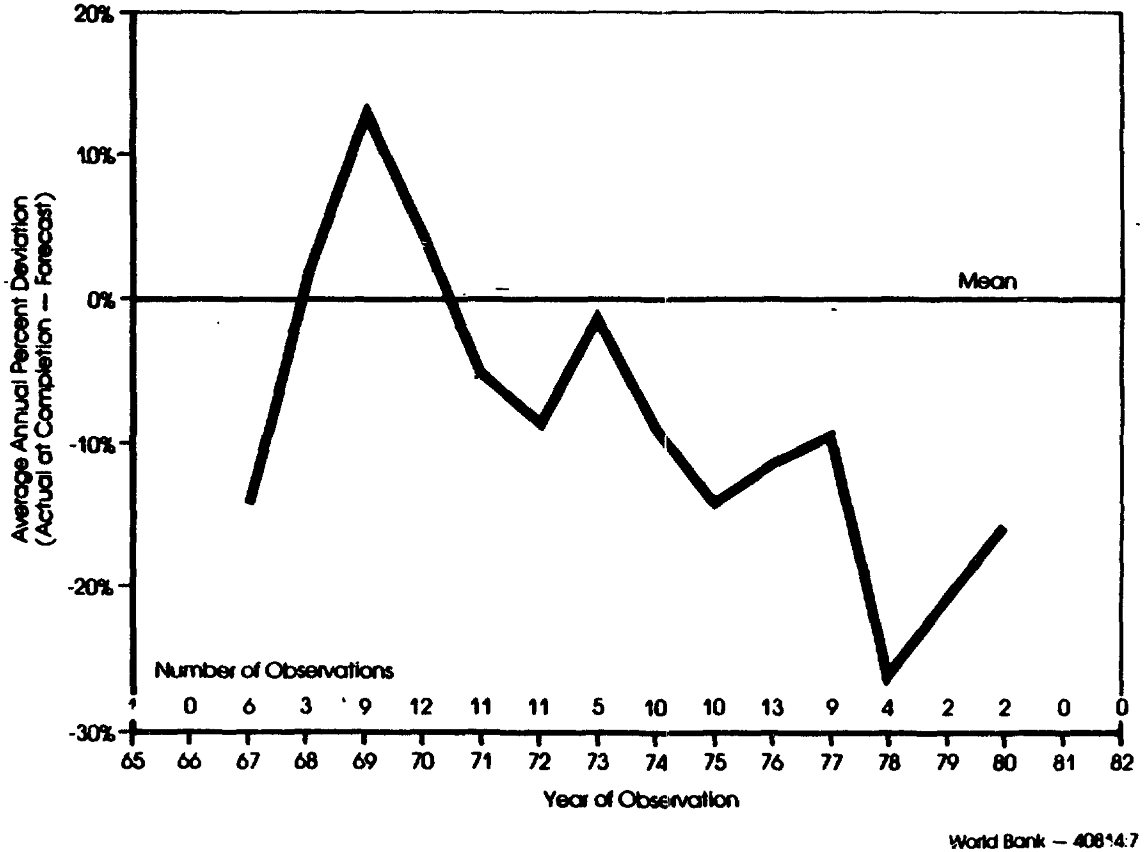

Figure 4: Trend of Sales Forecasts.

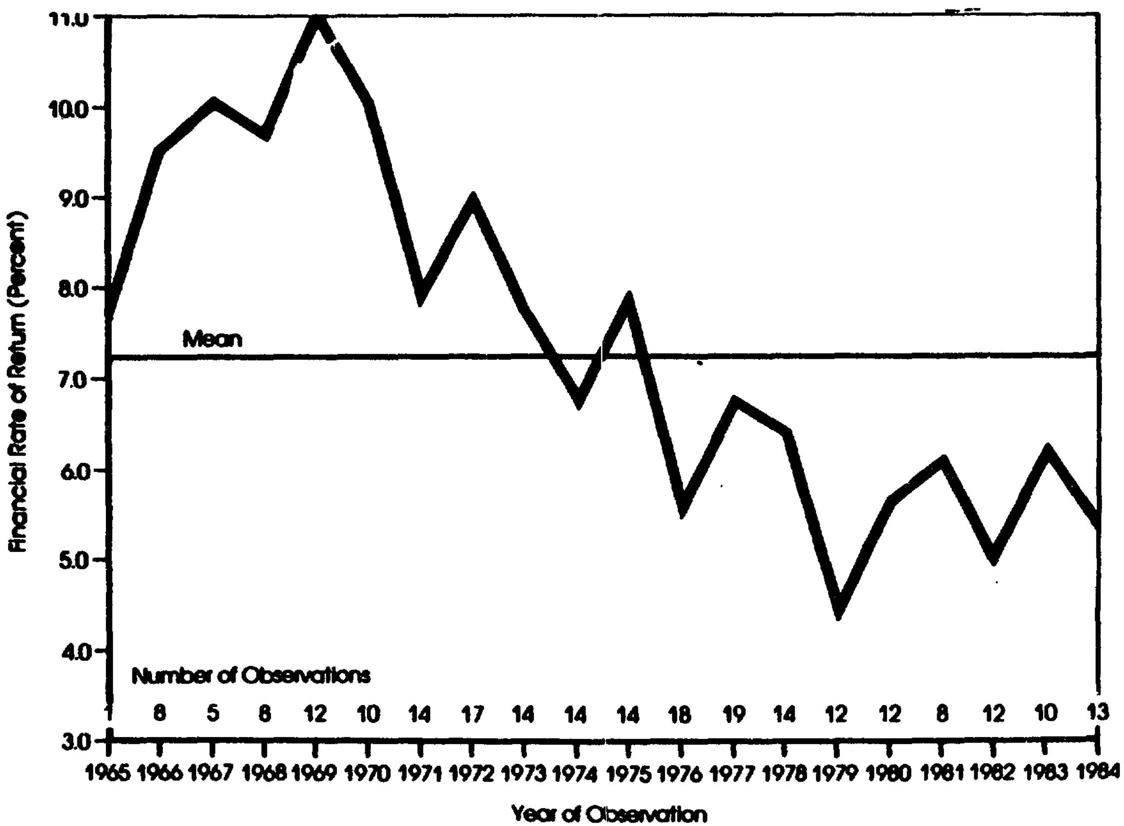

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Figure 5: Trend of Rate of Return on Assets.

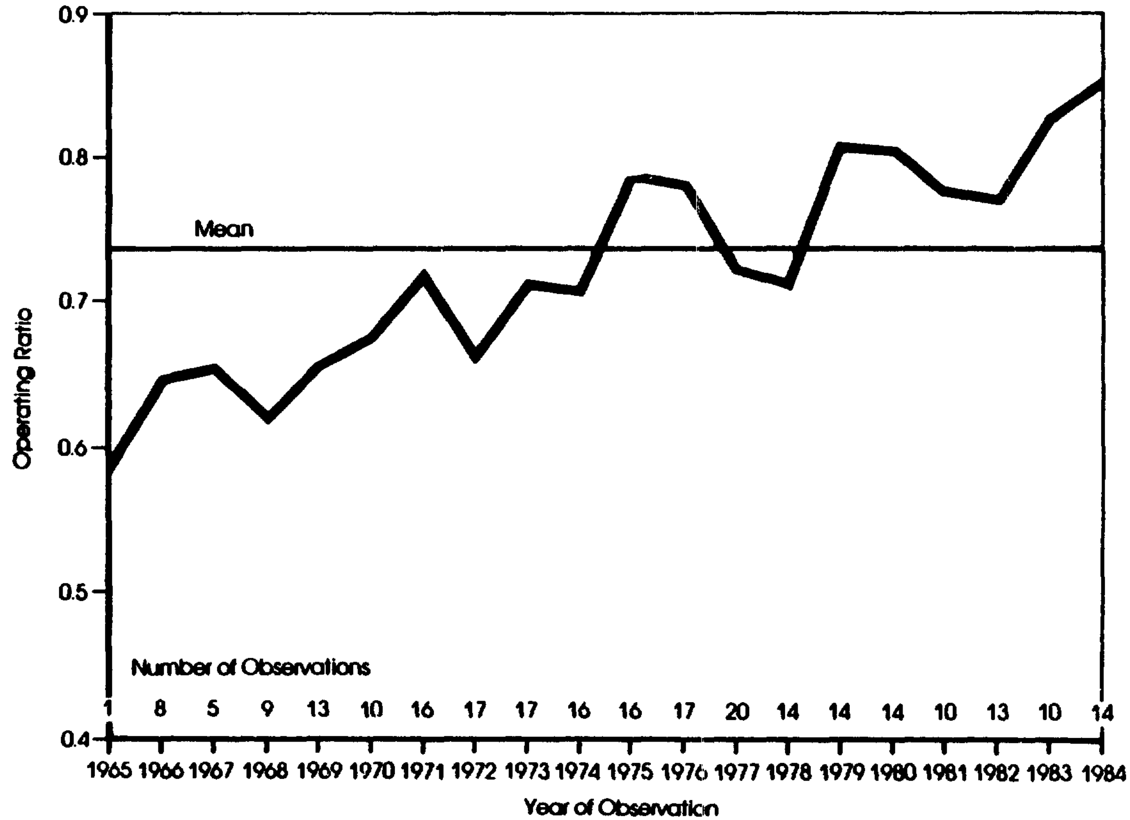

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Figure 6: Trend of Operating Ratio.

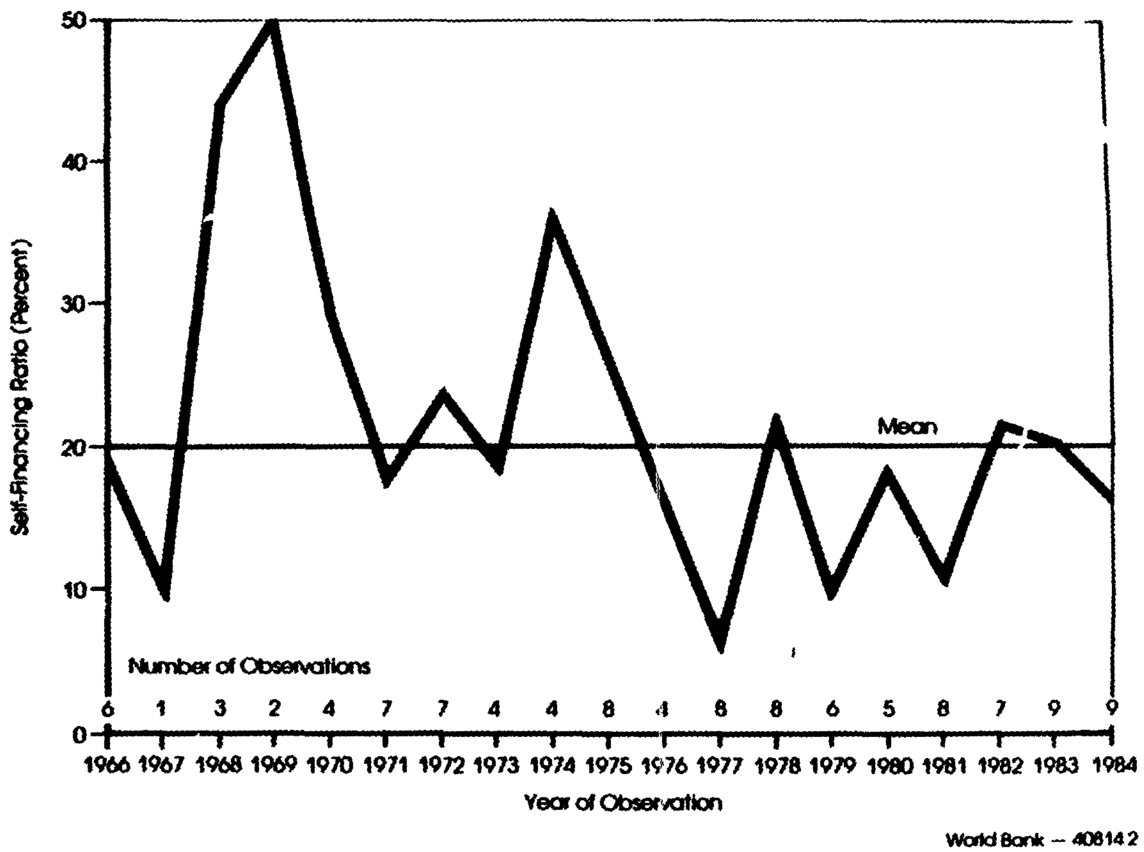

Figure 7: Trend of Self-financing Ratio.

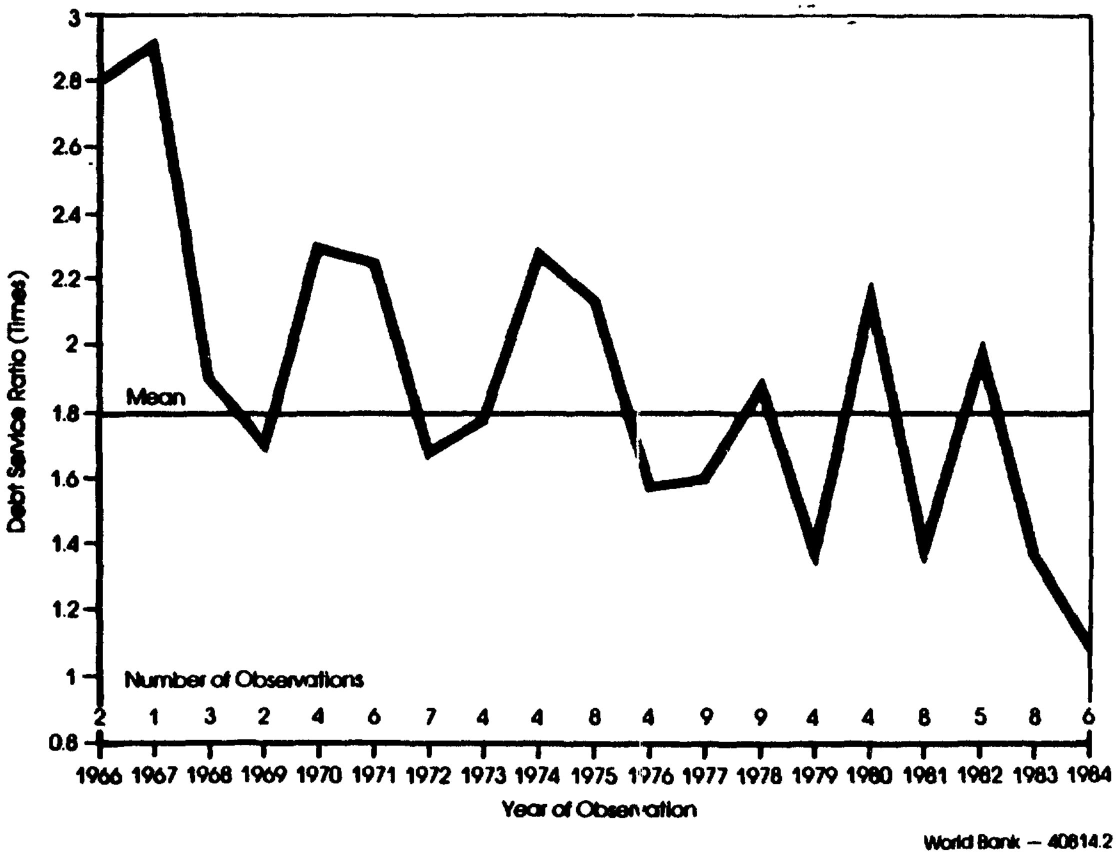

Figure 8: Trend of Debt Service Coverage Ratio.

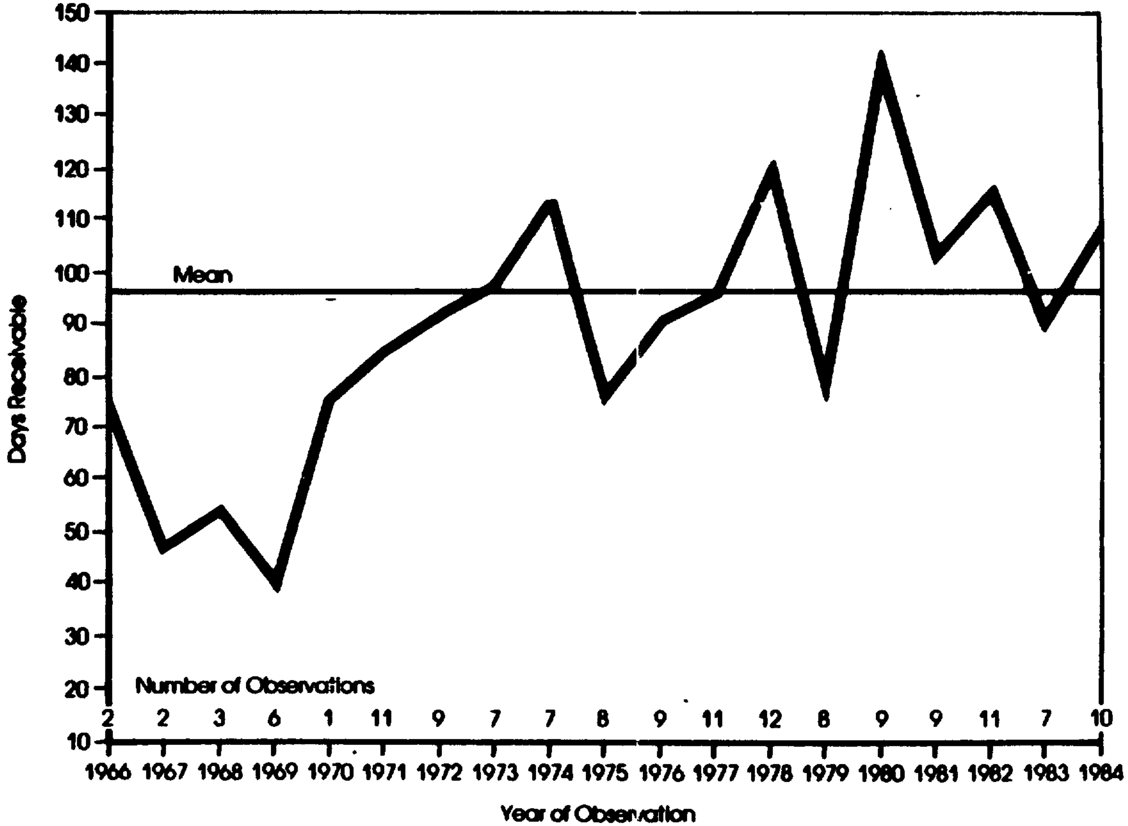

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Figure 9: Trend of Days Receivable.

As indicated in Table 2, the average rate of return for the period 1966-85 was 7.9%. However, the deviation about the mean was substantial, as can be seen from Table 3.

Table 3

Distribution of the Rate of Return on Assets

Rate of Return At Project Completion %	For Projects Approved in 1966-78 No. of Projects	%	For Projects Approved in 1979-83 No. of Projects	%
Below 4.0	23	22	13	40
4.1 - 6.0	20	10	5	15
6.1 - 8.0	17	17	4	12
8.1 - 10.0	13	13	7	21
10.1 - 12.0	12	12	0	0
12.1 - 14.0	7	7	0	0
Over 14.0	10	10	4	12
	102	100	33	100

For projects approved between 1966-78, 22% of utilities had rates of return equal to or less than 4% at project completion, and 17% had rates of return of over 12%. The situation has deteriorated for ongoing projects in 1984, when 40% of utilities had rates of return of 4% or less and only 12% had rates of return over 12.0%. Part of this deterioration was due to more rates of return being based on revalued assets.

For projects approved between 1968-78, about 18% had the same return as forecast at project completion and another 26% achieved higher rates of return than forecast. However, 55% of projects had lower returns than forecast and 43% of projects were below the targeted rate of return by more than three percentage points. For projects approved in the late 1960s and 1970s there appears to have been an increasing deviation between actual and forecast returns over time, particularly for those projects implemented during or after the oil crisis. This trend also appears to have continued for those projects implemented during the 1980s. The situation appears to have been better for projects implemented during the 1950s and 1960s, when a higher percentage achieved the targeted rate of return.

Operating Ratio

The average operating ratio for the period 1966-85 was 0.74. There was a significant deterioration between the periods 1966-73 and 1980-85, when operating ratios increased from an average 0.68 to 0.80.

For projects approved in the late 1960s and 1970s, actual operating ratios at project completion have, on the whole, been far lower than forecast at appraisal. Nearly two thirds of the projects approved from 1967-78 (all completed by 1982) had operating ratios more than five percentage points over that forecast at the time of project completion (i.e., the operating ratio was worse than forecast). Over half were more than 10 percentage points over that forecast and about 30% were 20 percentage points of that forecast. Only 9% of projects had lower operating ratios than forecast (i.e., performance was better than forecast).

There appears to have been a quantum deterioration after 1973 when oil price increases caused a jump in operating expenses for many utilities: the difference between forecast and actual operating ratios was far smaller, on average, for projects approved in the late 1960s and mostly implemented before the oil price increases than for those either under implementation during the oil crisis or approved after 1973. To some extent, the effects of the oil price increases were recognized in Bank appraisals since the forecast operating ratios were not as high as had been forecast before the oil crisis. Nevertheless, operating ratios at project completion were still substantially poorer than those forecast. For projects implemented during the 1980s there appears to be a similar margin of error in forecast and actual operating ratios as for projects approved in the 1970s after the oil crisis.

Nearly 40% of utilities had approximately the same (either plus or minus five percentage points) operating ratios at project completion and appraisal, and another 25% of utilities had improved their operating ratio by project completion. However, one third of utilities actually had worse operating ratios at project completion than at appraisal. Of particular concern is the performance of the 28% of utilities that had poor operating ratios at appraisal (i.e., 0.80 and over): about three quarters either did not significantly improve their performance or performance actually deteriorated during the course of the project.

From a regional point of view, utilities in East Africa were more successful at meeting the forecast operating ratio and thereby improving financial performance during the course of project implementation than other regions, as can be seen in Table 4. EMENA was particularly poor at meeting the forecast operating ratio, followed by LAC, and East and South Asia.

Table 4

Regional Breakdown of Operating Ratios for Completed Projects

	E. Asia	S. Asia	E. Africa	W. Africa	LAC	EMENA
Average						
SAR Forecast 0.62	0.70	0.61	0.60	0.67	0.54	0.67
Actual at Completion 0.75	0.80	0.79	0.66	0.80	0.65	0.86

Self-financing Ratio

The self-financing ratio is an indicator of the success and sustainability of a utility and measures the amount of investment requirements financed by internal cash generation. Unfortunately, it is one of the hardest ratios to compare from one project to another because of the inconsistent ways in which it is estimated, despite very specific OMS guidelines. Many estimates in appraisal reports do not include changes in working capital and a few even exclude payment of taxes. Consequently, the self-financing ratio had to be reestimated for a sample of projects for the purpose of this review according to the standard OMS definition:

"funds from internal sources equivalent to a defined percentage of average annual capital expenditures, after meeting operating expenses (before allowance for depreciation), debt service, taxes, dividends, increases in working capital, and other significant cash outflows, excluding capital expenditures."

Estimating self-financing ratios in accordance with the OMS definition in many instances lowers the ratio (on average by 25%). The serious effect of not including changes in working capital in the definition of covenants is rather dramatically illustrated in the case of a recent review of the internal cash generation of 14 state electricity boards (SEBs) in India for the purpose of meeting the requirements of a rural electrification loan. Action Plans submitted to the Bank for the SEBs indicated that in most years over the period FY 1986-90, 12 out of 14 SEBs would meet a 20% contribution criteria for disbursement of the loan. The covenant had been defined in a way that excluded changes in working capital. The inclusion of such changes would, on the figures submitted, have reduced the number of SEBs likely to meet the 20% contribution over the same period, to just two. Further analysis of current assets revealed that probably nine electricity boards did not have any working capital at all, i.e., they were technically insolvent.

The average self-financing ratio for the period 1966-85 (including the sample of completed projects and those under supervision) was below 20%, with a decline from 25% to 17% between the periods 1966-73 and 1980-85. The deviation about the mean was substantial, as can be seen in Table 5 for completed projects, during 1966-83.

TABLE 5

Self-financing Ratios for Completed Projects, 1966-83

Self-financing Ratio at Project Completion		Projects (with Estimated Ratios in Sample Survey Number	%
0		10	21
1 to 10		9	19
11 to 20		8	17
21 to 30		10	21
31 to 40		6	13
41 to 60		3	7
over 60		1	2
Average Ratio 18	Total	47	100

One of the weakest areas of forecasting appears to be for self-financing ratios, for they are not only consistently overestimated but also the magnitude of error is one of the highest. In about 65% of cases, the actual self-financing ratio was more than five percentage points below that forecast. Of particular concern is the 31% of instances where the actual ratio was more than 20 percentage points below that forecast and the 7% of projects where it was more than 50% below that forecast. The actual ratio was higher than forecast in only 14% of cases. The magnitude of the forecasting error on average has increased since the early 1970s and appears to have continued to deteriorate in the 1980s.

About 42% of projects actually had lower self-financing ratios at completion of the project than at appraisal and one half of these projects had ratios that were more than 20% lower. Of the one half of projects where utilities had poor ratios at appraisal (i.e., 20% and lower), nearly 50% of utilities had managed to increase self-financing by more than five percentage points by the end of the project. However, 25% of utilities actually had ratios that had deteriorated even further.

Debt Service Ratio

The debt service ratio is a good measure of whether the utility has earned sufficient revenues to meet principal and interest commitments on outstanding debt after meeting operating costs (before allowance for depreciation and after taxes) and it takes into account the terms of debt as well as the overall amount. The ratio can sometimes give the impression of a higher than actual performance of utilities because it does not take account of the waiving of debt repayments to government, indefinite rescheduling of debt payments or subsidized interest rates by government, as is often the case for utilities in developing countries.

The average debt service ratio for the period 1966-85 was 1.8: the deviation about the mean is not as great as for other financial performance indicators, as can be seen in Table 6.

TABLE 6

Debt Service Ratio for Completed Projects

Debt Service Ratio at Project Completion	No. of Projects	Percent of Projects
4.0	2	4
3.1 to 4.0	4	9
2.1 to 3.0	12	27
1.1 to 2.0	21	47
1.0	6	13
Total	45	100

About half of the projects had debt service ratios that were the same at completion of the project as forecast at appraisal (i.e., plus or minus 0.5) and another 16% were even higher. One third of the projects did not meet the debt service ratio targets and half of these were more than one point below the forecast level. There appears to be little difference in performance for projects implemented during the 1970s or 1980s. Just over one quarter of projects had debt service ratios that were higher at the end of the project than at appraisal and another 40% were about the same. One third of debt service ratios had declined during the course of the project. Of the 50% of projects that had poor debt service ratios at appraisal (2.0 or less), one half had not changed significantly by the end of the project and another quarter had actually deteriorated.

Days Receivable

The number of days receivable is a good indicator of the collection and commercial operations of a utility. Consequently, it is as much an indicator of institutional performance as an important component of working capital. For utilities with a monthly billing cycle (most utilities), the Bank normally regards 60 days as a reasonable value for a well-managed power company (although norms may vary according to country) and indeed the mean value of forecasts made at appraisal was 63 days. Unfortunately, performance by utilities fell far short of this target since the average for receivables was 96 days. There has been a clear deterioration over time, as can be seen in Table 7. Receivables increased from 77 days in the period 1966-73 to 112 days in the period 1980-85.

TABLE 7

Days Receivable for Completed Projects

Days Receivables	E. Asia	S. Asia	E. Africa	W. Africa	LAC	EMENA	Average
At Appraisal	84	86	120	93	73	152	94
At Project Completion	107	97	128	177	91	121	108

Only 18% of projects actually met the forecast number of days receivable (plus or minus ten days) by the end of the project and another 5% were higher. Of the 77% of projects that did not meet the forecast level, three quarters had days receivable more than 20 days higher than the forecasted level.

Days receivable improved from appraisal to project completion for about 30% of projects, but for another 30% of projects days receivable actually deteriorated, increasing by more than 20 days in most cases. For the 40% of utilities with poor performance at the beginning of the project (i.e., 90 days and over), only half managed to improve performance (by more than ten days) and nearly 30% actually had even higher days receivable by the end of the project. The percentage of projects which had a poorer performance at project completion than at appraisal appears to have increased in the 1980s.

Overall, the West Africa region had the greatest deterioration in receivables from appraisal to completion: EMENA was the only region to improve performance during the course of the project, as can be seen in Table 7.

Revaluation of Assets

It is now normal practice for the Bank to require the calculation of rates of return on the basis of revalued assets. In some countries, however, revaluation of assets for the purpose of calculating depreciation or preparing financial statements is not permitted; thus, not all power utilities could be expected to revalue their assets. About 42% of projects were for entities which revalued assets as a matter of course, particularly in LAC where asset revaluation had become necessary due to the endemic inflation that had begun earlier than in other regions. No trend was observable despite the general rise in inflation during the 1970s which could be expected to lead to the recognition of the need to revalue assets.

2.8 Institutional Performance

Performance, or efficiency indicators which can be relatively easily measured with a limited amount of data (given the lack of available data for many utilities) have not yet been developed. Therefore, to compare the efficiency of utilities in the past with the situation of today is imprecise at best. Because of high growth rates of demand, in some countries up to 15% p.a. over a ten year period, the plant in service has doubled in seven to ten years. The requirements for maintenance and efficient operations have increased commensurately and have strained the available management and manpower resources. It would not be surprising therefore to see a deterioration in the efficiency of operations of many utilities. Changing external conditions, such as foreign exchange shortages, cumbersome government procurement procedures, greater numbers of potential suppliers (both foreign and local) and volatile economic conditions, make the job of managing a modern utility more difficult than in earlier decades. A few indicators were reviewed to determine the trends over time, but all of them have limitations so that the results should be interpreted with caution.

Number of Consumers per Employee

This value is often used as a performance indicator by the Bank since it partially explains how efficiently labor is used. However, the ratio itself will not be the result simply of the level of performance of the utility since this will depend on the function of the utility, i.e., whether it is responsible for generation, transmission and/or distribution. The staffing level and hence the efficiency criteria would be different for each activity. In addition, the utility's use of force account construction labor as opposed to outside contractors will also affect the appropriate efficiency criteria to be used. Excluding those utilities that had bulk supply customers, a sample of utilities in the 1980s showed that about two thirds had fewer than 100 connections per employee which is a poor ratio even assuming the company undertakes force account construction. Only three out of 26 utilities studied had more than 150 consumers per employee, a fair performance for an average utility involved in distribution activities and not carrying out significant force account work.

Maintenance

A review of appraisal reports produced in the 1980s indicated that the level of maintenance varied considerably from one utility to another. Good maintenance is a contributing factor to achieving higher plant availability and efficient distribution and, therefore, more reliable service. Of course, poor maintenance may not necessarily denote only inefficiency on the part of the utility, for it could also result from lack of funds or foreign exchange for spare parts, and other factors which may be outside the control of the utility.

Quantitative measures of the adequacy of maintenance are difficult to establish; hence, it was necessary to accept the evaluations given in the appraisal reports. These evaluations were ranked on a five point scale from very good to very poor. For projects approved in the 1980s, twelve out of 26 utilities fell into the poor to very poor range - four in Africa, three in Latin America and three in S. Asia. On the other hand, nine utilities fell into the good to very good range - three in E. Asia, two in LAC and two in S. Asia. Most of these utilities had been established for many years so that there had been the opportunity to gain experience and improve maintenance over the years.

Overall Utility Efficiency

A similar rating of the overall efficiency of utilities was carried out as above for a sample of projects implemented in the 1970s and 1980s. The evaluation was based on the appraisal and audit reports' assessment of institutional performance, which may not be entirely consistent given the lack of precise criteria and the need for judgement on the part of Bank staff.

Based on a rating of one to five, the performance of utilities in the 1980s appears, on average, about the same as during the late 1960s and 1970s. The average utility falls in the "fair" range. In the mid-1970s, the percentage of utilities with poor performance increased quite sharply (33%), due in part to the Bank lending for the first time to new Borrowers with limited resources and experience.

W. Africa had the lowest overall rating of institutional performance and E. Asia the highest. These findings should be viewed with great caution because of the different circumstances of utilities in the 1980s, especially in terms of the increased magnitude of operations and changing external environment, and because of the subjective nature of the evaluation of performance.

The project audit reports include a rating of the extent to which utilities achieved the institutional targets set at appraisal. About 74% of projects were assessed as fair to good at having achieved institutional targets and another 6% met such targets to a limited extent. Twenty percent of projects were judged as having not met them at all. Unfortunately, institutional targets are often not clearly stated in many appraisal reports and more often than not the completion reports and appraisal reports were prepared by different project staff. It is likely, therefore, that institutional performance has been assessed as poor only in those cases where there were obvious institutional problems rather than when there were continuing but less glaring inefficiencies.

2.9 Conformity With Loan Covenants

Conformity with loan covenants was assessed for projects included in the two sample surveys of projects implemented from 1968-83. Rating of the utilities' conformity with loan covenants was based on a scale of one to five where one equalled 100% conformity and five no conformity at all. On average, there were seven major covenants per project. Those covenants that are repeatedly found in loan agreements mostly concern financial issues, including financial ratio targets, revaluation of assets, auditing requirements, tariff increases and tariff structures. Other covenants relate to improvements in planning, the structure of the power sector, the efficiency of the utility, and senior management appointments by the Borrower.

Based on an average of ratings for all covenants for each project, about 38% of utilities were considered to have conformed with loan covenants and about another third were rated as fair. Thirty percent of utilities were considered to have not conformed with many of the covenants at all. An evident limitation of this averaging approach is that each covenant is given equal weight; however, some are obviously more important than others. Nonetheless, any weighting scheme would be as arbitrary as the system of equal weights.

Those covenants that had the poorest conformity were those relating to rates of return on assets and days receivable. Nineteen out of 36 utilities did not meet the rate of return covenants, whether the returns were based on revalued or historical assets (see Table 8). In both cases most of the targets were set at 8-10%. This finding is not surprising considering the large number of projects that failed to meet the forecast rate of return, as discussed in Section 2.7. The situation seems to have deteriorated even more for those projects implemented during the 1980s, since nearly two thirds did not meet the rate of return covenant. Fifty percent of utilities failed to conform to the days receivable covenant - most of these had poor receivables at appraisal which was the reason for including such a covenant in the first place. Again, the situation appears to have deteriorated during the 1980s when more utilities were not conforming with the days receivable covenants. The situation appears to have been better during the 1950s and 1960s when such covenants were met on the whole, although often after some delays.

TABLE 8

Conformity with Loan Covenants for Completed Projects 1966-1982

Covenant	Number of Projects According to Conformity Rating a/						
	1	2	3	4	5	N/A	Total
Rate of return on historical assets	3	1	0	0	6	1	11
Rate of return on revalued assets	8	2	2	5	8		25
Debt service coverage	29	2	0	5	4	1	41
Self-financing ratio	3	4	0	2	1		10
Other financial ratios	3	5	0	0	1		9
Tariff increase, cr no reductions, change in tariff structure	15	2	0	5	4	1	27
Days receivables, govt. pay arrears	2	2	0	1	5		10
Economical/financial planning, Bank concurrence re changes	18	1	0	3	1	1	24
Government to provide adequate funds for for investment program if shortfall	16	1	0	4	0		21
Power sector changes	14	0	1	1	3	2	19
Tariff or marginal cost study	6	0	1	0	0		7
Submission of audits	20	2	1	6	0	2	31
Appointments to senior management	16	0	1	0	1		18
Asset revaluation	10	1	1	3	2		17
Improve efficiency of utility	13	1	1	1	4	1	21
Limit on investment in other activities	7	0	0	0	0		7
Other	22	1	0	8	8	4	43
Total	205	25	8	44	48	13	343

a/ Total of 50 projects. Each project had more than one covenant.
Rating key: 1 = 100% conformity
5 = no conformity whatsoever
n/a = information not available

III. REASONS FOR PROJECT AND SECTOR PERFORMANCE

The reasons for project and sector performance can be broken down into three separate categories: (i) those that are outside the control of the utility and the national government, such as natural disasters, world economic conditions and unstable security situation, (ii) those that are outside the control of the utility but which can be controlled by national governments, such as tariff setting, broad investment policy and procurement procedures; and (iii) those that are within the control of the utility, such as management, planning and programming of work. Not all of the variables that affect performance fall into only one category for there is obviously some overlap; for example, high losses may not only be due to the poor performance of the utility but also to the government's reluctance to prosecute those with illegal connections or to allow the utility to cut off the supply of electricity for non-payment of bills. Several variables usually account for differing levels of performance but it is not possible to determine the sensitivity of overall performance to changes in only one variable. Many factors are difficult to quantify and isolating the effect of individual variables is equally difficult. With these points in mind, the three categories of factors affecting performance were examined.

3.1 Exogenous Factors

Exogenous factors which are essentially outside the control of the power entity or national government only partially explained either good or poor performance of utilities. Of those projects which had significant delays, 15% cited external events as the cause of delay for any one component of the project, such as internal security problems, security problems in other countries through which goods for the project had to be transported, poor weather, and major natural disasters. More projects were affected by the country's deteriorating economic situation; about 25% of projects were delayed because of lack of funds for the project. Most of the shortage of funds appears to have been foreign exchange, particularly where there were cost overruns (although there may have been misreporting of shortage of foreign exchange where Borrowers were unable to provide the local currency counterpart). Lack of funds has been a particular problem during the 1980s.

About 60% of projects with delays cited contractor problems as one of the reasons for the delay and nearly 40% cited late delivery of equipment. Such problems involved poor management of construction works by the contractor (both local and foreign), poor supervision by consultants, and dismissal of the contractor or supervising consultants because of incompetence. These causes have been labelled as exogenous factors but in reality part of the problem stems from the weak control by utilities themselves. Contractors frequently complain of poor project management by the utility and often the contractor's unsatisfactory performance is allowed to continue for far too long before the utility takes decisive action.

General world economic conditions over the study period were obviously the main external factors that affected the success of projects and sector performance. However, the power sector was frequently adversely affected by not only downturns in the world economy, but also the poor adjustment to those deteriorating conditions by national governments. As a result, local inflation was often increased by factors other than changing external economic conditions. However, a detailed study would be required to determine the extent to which power sectors were affected by purely external economic conditions and purely national economic policies.

Naturally, the most significant effect of changing external economic conditions was on the level of demand for power and financial performance. For 60% of cases where the demand forecast for power sales was not met, a principal reason given was an unexpected downturn in the economy or an unexpected downturn in one important consuming sector of the economy.

Inflation

Not surprisingly, over one half of the projects which had cost overruns gave inflation or an increase in the price of key items of equipment as one of the reasons for increased costs. About one third of these projects suffered from particularly high increases in local costs. On the other hand, the effect of world recession in the early 1980s has had a beneficial effect on costs insofar as the resulting competition for contract awards has led to lower costs and significant cost underruns (for about one half of the projects with cost underruns).

The effect of inflation on the financial performance of utilities has been particularly serious. The average annual increase in the wholesale price index as a proxy for the increase in costs for utilities gives some indication of the inflationary pressures that utilities have had to face. However, not all of these increases would be directly reflected in the utilities' costs, since existing assets are not revalued in many instances and the full cost of oil price increases sometimes have not been passed on to the utility. Average annual rates of inflation of over 20% between 1973 and 1981 were encountered by about 40% of the utilities sampled and another 50% experienced rates of between 10-20%. However, the situation has improved in the 1980s with inflation rates below 10% for the majority of utilities reviewed (with some notable exceptions in Latin America, for example Brazil and Uruguay). Of course, if tariffs had been increased in line with increased costs the inflationary impact on the utility would be minimized.

Exchange Rates

The volatility of exchange rates has had a particularly significant effect on project and sector performance during the late 1970s and 1980s. Thirty-eight percent of projects with cost overruns cited currency fluctuations as one of the reasons for such overruns, but these were mainly projects implemented in the late 1970s. The strengthening of the US dollar in the first part of the 1980s decade has resulted in cost underruns (with costs expressed in dollars) for about one third of projects. Of course, one of the major problems of expressing all costs in US dollars is that nominal costs will go up and down with the fluctuation in the US dollar which has been quite volatile over the last few years. Now, after the recent period of cost underruns, overruns can again be expected because of the recent fall in the dollar which may not have been anticipated in project cost estimates. If expressed in local currency, the impact of cost increases and decreases will look very different from the behavior of the corresponding US dollar cost, especially if most of the procurement was in currencies other than US dollars.

Interest Rates

The high interest rates in the early 1980s has obviously resulted in higher debt service obligations for power utilities and was given as one of the reasons for poor performance by nearly one third of utilities. A more detailed study would be required to determine the magnitude of the increase in debt service obligations, for they are not so readily apparent in those cases where tariffs were increased in line with increased costs, including debt service.

3.2 Potentially Controllable Factors in the National Environment

The performance of the power sector could be significantly improved if governments were to take certain measures that would either remove restrictions on the utilities' activities or improve coordination and planning of the sector. Such measures are outside the control of the utility but completely within the purview of government. Government procurement procedures are often slow and cumbersome resulting in delays in the award of contracts. About one quarter of the projects with significant delays cited slow government procedures as one of the major reasons for the delays. There does not appear to have been any improvement over time since the same percentage of projects are still suffering from similar problems. Slow bureaucratic procedures have also resulted in delays in transmission projects because of the lengthy time to obtain wayleaves.

Government interference in the planning, managerial, financial, and day-to-day operations of the utility appears to be a very serious problem for a small but significant number of utilities (about 10% in the sample) and a moderate but serious problem for about 25% of utilities. Very few variables in the study were found to be strongly correlated, but one of the highest correlations was between the level of institutional performance and government interference. As institutional performance weakened and the number of unmet institutional improvement targets increased, the likelihood of government interference became greater. The total level of losses (technical and unaccounted-for energy) had a moderate correlation with the level of government interference which is not unexpected, since governments can put pressure on the utilities to refrain from disconnecting those who do not pay their bills. In addition, the prosecution of large numbers of people with illegal connections would be politically difficult in some countries. There was also some relationship between the overall conformity with loan covenants and government interference, i.e., the less covenants were conformed with, the more likely there was to be government interference in the operations of the utility.

The correlation between institutional performance and the extent of government interference cannot be used to demonstrate causality. Governments maintain that they become involved in sector management, i.e., interfere, because the power utility is weak and/or inefficient and such involvement is desirable and necessary. Critics contend, however, that such interference is the cause of inefficiency and poor performance and that management and staff weaknesses can be overcome by paying better salaries and giving more autonomy to the utilities.

Undoubtedly the biggest impact of governments is on the financial performance of utilities because virtually all governments control tariff levels. Of those utilities which did not meet their financial targets, about 70% cited failure to raise tariffs as one of the reasons for poor performance. Significantly, practically all of those with good financial performance gave timely tariff increases as one of the major reasons. In some cases, governments have lacked the commitment to reuse tariffs or have failed to understand the Banks objectives. During the 1980s, failure to raise tariffs does not appear to have contributed to poor financial performance as much as the lower growth of sales (due to the deteriorating economic conditions in many countries). The extent to which average revenues kept up with operating cost increases was reviewed for a sample of projects implemented from 1968 to 1984. In real terms (expressed in local currency), average revenues kept up with increases in average operating costs per KWh in one half of projects studied and were even higher in another 20% of cases. However, of those cases where revenue increases were the same as operating cost increases, depreciation was based on the historical cost of assets and not revalued assets. Therefore, in general, tariffs had not been increased sufficiently to keep up with the increased cost to replace assets, let alone provide for adequate self-financing of new investments. Surprisingly, tariffs appear to have lagged more behind operating cost increases during the early 1970s: during the 1980s more utilities have managed to keep average revenues in line with operating cost increases. However, this does not mean that these utilities are financially healthy since a substantial number had a low initial level of performance. Factors such as the generation mix appear to have had little influence on financial performance including the operating ratio.

3.3 Factors Within the Utility

As discussed in Section 2.7 (self-financing ratio), some utilities have serious cash flow problems because of inadequate working capital. The failure to provide adequate working capital results in many utilities managing their finances on a hand-to-mouth basis, because funds are not readily available to pay bills and sometimes, salaries and wages. There are known cases where funds borrowed locally, ostensibly for capital projects are being used for working capital. Such practices, which are unacceptable, result in project delays and higher costs. There is a need for greater analysis both of the composition of working capital and to determine working capital needs. Contribution to investment covenants should be based on OMS 2.22, and where necessary, supported by a well-defined working capital covenant. It is also obvious that if Bank standards are to be maintained, Bank management and staff must follow the carefully prepared and approved guidelines for financial covenants.

The problems that tend to be most frequently addressed are those that are inherent weaknesses of utilities themselves. Weak management, poorly qualified and inexperienced technical staff, weak programming and planning, poor supervision, etc, seriously affect the performance of the power sector.

Procurement

One of the major documented weaknesses of many utilities is weak procurement procedures. The extent of this weakness is constantly underestimated by the Bank, for nearly 60% of projects with delays cited the utility's slow procurement procedures as a major reason. The bureaucratic process for awarding contracts, delays in drawing up bidding documents, and mistakes in procurement procedures resulting from unfamiliarity or disagreement with Bank procedures often resulted in delays of six to twelve months. One would have expected to find some improvement over time as more utilities were on at least their third project financed by the Bank. However, available data shows that procurement was as much a problem in the 1980s as in earlier periods. In a few cases, delays were due to new procurement or other procedures. In many instances, both the Bank and the Borrower failed to identify these constraints early enough to introduce mitigating measures as part of the project. In other cases, questionable procurement practices were resisted by the Bank, resulting in considerable delays.

Other Problems

About 20% of projects had substantial delays because of the utility's general inefficiency, lack of control or poor judgement. Either consultants were terminated prematurely, or force account operations were poorly organized and supervised, or there may have been shortages of staff to administer construction programs. Technical problems were cited as a reason for delays and cost overruns for about one half of the projects but most of the problems were considered not to have been within the control of the utility but were unforeseen design and engineering problems, such as additional preparation works for construction projects and faulty installation of equipment. Poor cost estimates which are ultimately the responsibility of the utility (although the Bank has to approve such estimates) was one of the reasons for project cost overruns for about 20% of projects. Revisions to projects was a reason for cost overruns for about 40% of projects, at least some of which were due to poor preparation of the original project by the utility. Of the investment programs for which there were delays in implementation, about 25% were the result of institutional inability to carry out the program.

One of the most significant correlations observed was between institutional performance and level of losses. The higher the losses the poorer the institutional performance. Poor billing systems, inability to read meters correctly and in a timely fashion, poor control of illegal connections and poor operation and maintenance of the network were all contributory factors to high loss levels. Admittedly strong government support is often required to implement effective loss control programs, but much can still be done by the utility itself if it has the required determination. Overloaded distribution systems also account for substantial losses but many of the systems are overloaded because of illegal connections and failure of the utility to control the growth of new connections.

Some recent statistical analysis in EGY to determine the relationship between technical and financial performance, yielded mixed results. Institutional performance was measured by the overall efficiency of the entity (Section 2.8), adequacy of maintenance, and loss levels, while financial performance was based on indicators such as the rate of return, level of self-financing, debt service and operating ratio. These results suggest that entities with poor institutional performance generally tend to also have poor financial performance. However, there are some entities with poor financial performance but demonstrating reasonable technical and institutional performance. The technical indicator that does appear to be most correlated with financial indicators is the level of losses. Utilities with high losses also tend to have high receivables from customers and poor operating ratios and the greater the deterioration in the financial performance of utilities, the more likely that losses have also increased over time.

Increased receivables was given as one of the reasons for poor financial performance by 30% of utilities. High receivables are due in part to a weak institution since failure to collect from customers indicates a poorly administered billing system. However, high receivables are frequently due to failure of government agencies to pay their bills, a matter which is completely outside the control of the utility.

IV. ISSUES, OPTIONS, AND RECOMMENDATIONS

4.1 Issues Arising from the Retrospective Review

One important finding of this survey confirms the general belief that developing countries have made great strides in improving access to electricity but, with some notable exceptions, have not had as much success in improving power sector and project performance. The study results also show that project implementation and financial performance have been progressively deteriorating or have shown little or no improvement over the last 20 years, despite the fact that Project Performance Audit Reports (PPARs) have generally shown most projects to be economically justified at completion. Specific problems such as the need for better cost estimates have been recognized and addressed in annual Project Implementation Reviews (PIRs), but the sector does not appear to be making significant improvements in performance. The Bank has also attempted to deal with the problems through the preparation of sector and individual country strategies and other internal reviews. Keeping in mind the amount of effort which has already gone into dealing with issues, the options and recommendations presented here cannot provide instant solutions. Rather, they are intended to provoke further thought on possible strategies and help in reorienting the focus of the power sector towards broader energy sector ad macroeconomic linkages rather than focussing narrowly on traditional project issues.

Another principal conclusion of this study is that both the Bank and its Borrowers are over optimistic in most aspects of project design and implementation including demand forecasting, project implementation, financial performance, loss reduction, and the level of maintenance to be achieved. With the exception of cost estimates, the actual results at project completion have been less than forecast for all the indicators of project performance. Given the available evidence from this study, there appears to be little likelihood that sector and project performance would improve significantly unless changes are made to the Bank's and Borrowers' basic approach to power sector operations.

There are several factors which contribute to this conclusion. First, forecasts are often seen in part as targets with a certain expectation that they will not be met. In many countries there is a need to aim high in order to lay claim to funds from the development budget; hence, high growth rate forecasts are welcomed as a justification to allocate more funds to the sector than would otherwise be granted. While a sensitivity analysis of the effects of reduced demand and higher costs is routinely carried out by the Bank in connection with the economic evaluation of projects, only recently (1987) has it become a requirement to carry out similar sensitivity analyses as part of the financial or engineering evaluations.

Within the Bank there is an understandable pressure to meet the lending program. There is also a reluctance at each stage in the project cycle to cause delays in loan processing. The natural tendency is to advance to the next step in order to maintain momentum in project preparation or implementation and thereby meet the usually very tight schedules. Only in hindsight is it possible to assess whether or not a single issue was sufficient justification to delay processing, suspend negotiations or whatever. It is not surprising therefore that targets are not met. The inevitable result, however, is often a somewhat fatalistic if not cynical expectation on the part of staff that the results will not be achieved. There is also a consequent loss of credibility of the Bank by the Borrowers.

Basic questions should be posed and better addressed, concerning the standards that are set for each utility and the feasibility of meeting them. Perhaps more significantly one should ask what the consequences are of not meeting demand forecasts, financial covenants, loss reduction targets, etc. Would the loan still be justified in terms of institution building or in sustaining the sector so that electricity supply can be maintained to existing productive sectors? Does the loan provide leverage with regard to sector and macroeconomic issues?

The options which are within the control of the Bank relate to the instruments at its disposal and the leverage which it has at different levels. The Bank does not have much leverage in large countries or where project loans are small relative to total investment in the power sector and the economy as a whole. Effective options in different countries will range from specific items in project design, design of loan covenants, sector lending by tranches with conditions, or broadly based policy lending with varying degrees of importance depending on the issue and the country.

Project composition and the mix of investment among generation, transmission, and distribution can be influenced by the Bank but these matters are ultimately under the control of the government. The results of this study, however, suggest that there has been a relative lack of support by the Bank for subtransmission and distribution investment. During the period 1965-1980, the average composition of Bank lending was 58% for generation, 22% for transmission, 9% for distribution, and 11% for other components. Investment in distribution plant typically is of the order of 30% of total and, in the absence of Bank participation, utilities have sought other sources which have less concern for the overall sector or have made piecemeal and often substandard extensions to the distribution networks. The result over the long term has been high losses and a poor quality of service.

There are, of course, many factors other than the Bank's involvement that will contribute to, or detract from, the outcome of projects. These factors are examined below in terms of their susceptibility to be controlled at various stages and at different levels intervention. These factors may be (i) entirely exogenous and beyond the influence of either the country or the Bank, (ii) within the purview of the national government and the national economy and perhaps largely a matter of political will to control, and (iii) within the control and management of the power sector as presently constituted or if given the autonomy to act as required.

Exogenous Factors

The state of the world economy is the obvious major external factor which must be taken into account in the project design but which is not controllable by the government or utility. The world economy in the

1970s and 1980s has been more volatile and hence, more difficult to predict especially since the oil crisis. The cyclical effects are difficult to identify until they are well established. For instance, as oil prices were increasing rapidly after 1979 there was little expectation of the stagnation in prices by 1982 followed by a complete reversal of prices by 1986. The 1982-84 recession led to much lower civil works contracts for projects now underway. While this situation will change again, there will be an inevitable lag as the required adjustments are made to base cost estimates to reflect the changed market conditions. Conditions of international inflation are more systematically dealt with by EPD in terms of the Manufacturing Unit Value Index relating to goods shipped from industrialized countries to developing countries.

While inflation can be taken into account in project costs and loan amounts, there will remain the need for assessing inflation effects on the revaluation of assets. A further review of revaluation methods is warranted to account for both local and international inflation as it affects the fixed asset base of power utilities and the impact this would have on operating costs and, hence, tariff requirements.

There is obviously not much that can be done to influence the external factors themselves. To a limited extent the Bank can work at the macroeconomic level (where it has leverage) to persuade governments to adopt economic policies that do not aggravate the effects of external factors. These policies would relate to matters such as exchange rates, local interest rates and fuel prices and would have a fundamental bearing on pricing. The Bank and Borrowers should also adopt a less deterministic, more scenario-oriented approach that is better suited to dealing with uncertainty.

The variability of funding available to support development projects in each country has also become a significant factor. There has been a shifting not only of the level of support from year to year but also a shifting emphasis among sectors, e.g. agriculture, urban, energy, and industry have all been considered as requiring particular emphasis at different times. There is a tendency among the international funding agencies to shift priorities all at the same time from sector to sector and within the power sector. In this circumstance, it would be desirable to assess the rate of growth which can be supported in the power sector and the priorities for expansion (generation, transmission, and/or distribution) in the light of available funding.

Factors Controllable at the National Level

(a) Tariffs and Pricing

The poor financial state of utilities as discussed previously is in large part due to the failure of government to permit timely and sufficient tariff increase. This problem is reflected directly by deteriorating operating ratios. As a result, many utilities are dependent on government for contributions to investment, preferential interest rates, the waiving of debt, subsidized interest rates, and contributions to operations in a few cases. Governments have a reluctance to increase tariffs in times of inflation or recession. Even if tariff adjustment formulas exist they may not be applied, especially in countries where economic conditions have deteriorated. There can be no solution to this problem in the absence of government will and/or Bank leverage to ensure that tariff action is taken as required.

The importance of sound power sector pricing policies is part of the overall issue of pricing in many countries. It will be difficult, however, to obtain compliance with tariff covenants if a government does not share the Bank's views on the overall need for economic efficiency pricing in general. There is increasing realization that in many countries, the efficiency, resource mobilization and social equity objectives are not inconsistent, and can be met by raising the average price level and improving the structure of tariffs.

(b) Revaluation of Assets

About 40% of countries have formally instituted a policy of asset revaluation which leads to a realistic provision for depreciation as a component of operating costs. The remaining 60% of countries either do not revalue assets or do so partially or inconsistently leading to an understatement of costs and, therefore, of tariff requirements. Many governments are concerned, however, that asset revaluation would contribute to inflation and that historical cost accounting should continue to be the basis for determining costs. As this is a fundamental issue in accounting practice and pricing policy it would need to be dealt with by the government as it cannot be addressed directly from within the power sector.

(c) Allocation of Funds to the Power Sector

The rate of expansion of the sector depends directly on the allocation of investment funds by government through the usual five year plan as well as through annual allocations from development budgets. Increasingly in LAC, S.Asia, and in Africa there is a lack of counterpart funds to support ongoing projects let alone embark on new ones. In addition, there is very often a lack of foreign exchange for spares and, in a number of cases, fuel for regular operation. This problem is, of course, not unique to the power sector; however, it is clear in such circumstances that governments place higher (perhaps justified) priority on other sectors. The issue is then fundamental -- can the country afford to continue expanding the power sector at the currently planned pace? If not, what should be the priorities within the sector?

(d) Procurement

The procurement procedures of government have affected all sectors; for the power sector about one quarter of projects have experienced delays because of slow and cumbersome government procedures. The problem can only be dealt with at government level, not within the power sector; however, there is often an implicit assumption that changes in procedures can be agreed and implemented by the power utility when, in reality, such changes are far more difficult to implement because of considerable vested interests in existing procedures.

(e) Management Appointments

In virtually all countries, senior managers and often middle managers are appointed or approved by government. A previous study of power utility performance showed the quality of leadership and management to be the single most significant factor leading to good performance. An important issue arises if competent managers are not available and/or existing managers cannot be changed. The Bank must then consider and modify sector objectives accordingly. Consideration must be given to the time required for institutional adjustments since changing management will not result in immediate improvements in performance.

(f) Autonomy of the Utility

In addition to the appointment of managers, governments have direct control over the autonomy of the utilities. In many cases, autonomy is purely nominal with most real control remaining vested in the government. Governments are reluctant to relinquish this control when the quality of service is poor, operations are inefficient, and management is perceived as weak. The government may, of course, be responsible in part by failing to permit adequate salaries which cannot attract or hold competent staff. Attempts at institution building through training are thwarted by the departure of staff once trained.

It is clear that governments will not grant more autonomy without some assurance of improvements in efficiency and sector performance. The concept of a contract plan between the government and utility was used successfully in France for many years, and has also been tried in several countries such as Ivory Coast and Senegal. In this approach the setting of policy objectives is done by the government in consultation with the utility's senior management, who then are accountable and responsible for implementing these policies. In return, increased autonomy and control of resources is given to the utility. Thus the roles of the utility and the government are spelled out; however, the ultimate success of the contract plan depends on its realism and the willingness and ability of both sides to adhere to the contract.

Factors Within the Utility

The degree of autonomy enjoyed by the utility will determine the number of factors and extent to which they are controllable or influenceable by it. The principal items which are generally controllable are (a) day to day operations, (b) metering, collection, and billing, and (c) accounts receivable. Given the control which most governments have of the sector investment budgets, and frequently, the operating budgets of utilities, these items can only be influenced by the utilities through the planning and budgeting process.

External factors may again predetermine the extent of control of the utility since foreign exchange shortages may not permit optimum plant operation because of lack of spares or shortage of fuel. Receivables may increase because the governments themselves do not pay their bills or delinquent customers cannot be prosecuted or disconnected. A recognition of the degree of control which the utility has to meet the covenants is required before realistic covenants can be drawn up.

4.2 Options and Recommendations

A sound power sector pricing policy whereby timely and sufficient tariff increases are implemented is usually cited as a major solution for improving the poor financial situation of many utilities in many borrowing countries. The Bank and its Borrowers have traditionally agreed on financial goals, including tariff increases, in loan covenants. The commitment of borrowers to these covenants can easily be questioned as it is found that over half of the borrowers did not conform to the covenants requiring tariff increases to meet targeted rates of return or self-financing ratios. Even when there was conformity, this was frequently attained only at the end of the project when there was a condition of effectiveness for a follow-on project. It appears, then, that it would be necessary to have follow-on projects to ensure leverage and successive tranches could be released to ensure compliance. This could be successful for transmission and distribution projects but would not be practical for large generation projects where an assurance of financing is essential to carry out the project at minimum cost.

Leverage is a particular problem for the Bank in some of the larger countries. In these instances the Bank has only two options — to reduce or stop lending, or to continue lending in order to maintain its dialogue with the anticipation of an eventual influence on policy in the power sector.

The problem of leverage can be addressed at the sector level whereby larger loans could be made available as lines of credit for any component of an agreed upon investment program. More leverage would be expected with larger loans. This outcome could be expected, however, only in the case of smaller countries. One remaining course is to tie performance on matters such as pricing and procurement (which are common to several sectors), to policy-based lending operations.

Failure of governments to increase tariffs when required is often cited as a reason for poor financial performance of many utilities. However, this may be an over-simplified explanation because there are other contributing factors relating to costs which need greater attention. These factors include high losses, high debt service leading to a low debt service coverage ratio, and too rapid sector expansion which is not affordable, leading to yet higher debt service requirements. As a result of these factors, internal cash generation has been insufficient to meet investment requirements which in turn has led to poor maintenance and service quality. These is also generally a much higher need for working capital than has been considered in the calculation of the self-financing ratio in financial projections.

More analysis of recurrent costs needs to be undertaken as part of sector planning in addition to the detailed evaluation of the least cost investment program that is carried out at appraisal. The imbalance in sector investment and underfunding of distribution in many cases has led to a deterioration in service quality and an increase in losses. A reduction in losses would obviously reduce costs as well as increase revenues.

There is a need for Bank staff to limit their involvement in the actual planning of projects in borrowing countries. It has been observed that there is a tendency for the Bank to provide greater input throughout the project cycle due to the lack of planning capabilities in many countries. Such involvement is often necessary as there is neither continuity nor sufficient transfer of skills in the conduct of planning studies to provide for the required in-house capability. Bank staff frequently provide this continuity, particularly at the time of appraisal; however, there would be a danger that the Bank would lose its objectivity in the process if it becomes too closely involved.

Many of the findings of this study which relate to broad sector issues focus on questions of priorities within the power sector and in some cases to the priority of the power sector within the economy as a whole. It has been a generally held view that electricity is essential for economic development and that expressed demand should be satisfied as rapidly as possible. Given the evidence of the last two decades, it is apparent that issues should not necessarily be assessed in terms of a demand forecast but rather in terms of supply conditions. Where quality of service has declined and losses have not been reduced then there should be more emphasis on maintenance and rehabilitation and less on service expansion. Sector expansion must be geared to affordability given the highly capital intensive nature of the power sector. Much greater emphasis on broader energy planning and analysis of intersectoral and macroeconomic linkages is needed to ensure that all supply constraints are adequately considered in sector development. These factors include not only foreign and local funding availability but also management and professional staff capability for all aspects of system operation and development.

The Bank has increasingly supported investment planning studies. However, these have tended to focus on long term generation planning or the preparation of the next project. There is a need to broaden the scope of the studies to include subtransmission and distribution in detail as requirements for ongoing operations and maintenance, and manpower development. If the sector plan reveals that there is a constraint in a particular area which cannot be resolved from within the power sector, then the planning forecast should be adjusted to stay within the bounds of the constraint. In many countries, the primary constraint will be the percentage of total GDP that should be allocated to the sector.

Assuming a greater emphasis on improving the efficiency of the utilities, there is a need to determine why some countries such as Thailand, Korea, Tunisia, and Malawi have successfully increased their efficiency, while repeated projects in other countries have met with little success. It does appear that macroeconomic conditions have a strong bearing on the likelihood of success. If the government is following uneconomic policies and the national administration is generally weak and inefficient, then it is unlikely that the power utility will succeed in making significant improvements in performance.

Given the increasing climate of uncertainty which affects all aspects of planning and performance, it is essential to go beyond the simple deterministic approach based on expected values, by evaluating different scenarios and paying greater attention to risk analysis. At the level of project preparation, this includes risk analysis with regard to the effects of uncontrollable or uncertain factors on:

- demand forecast
- project costs
- economic justification of the project
- financial performance - debt service
  - required tariff increases, e.g. fuel adjustment clauses
- availability of funds for the project

At the sector level, there is a need to constantly review the power sector investment program where international and national economic conditions are changing rapidly. In particular, there is a need to review demand forecasts (in 60% of cases where actual demand was below the forecast, one of the reasons cited was poor macroeconomic conditions). If there were large increases in costs in general and not just for the project, would the investment program as planned still be justified? If so, would local and foreign exchange funds be available? Risk analysis in this sense is seen as being more extensive than the simple form of sensitivity analysis normally carried out at appraisal. This is the sort of analysis that a well established utility would undertake as part of its medium and long term planning.

Finally, for the Bank itself, there is a need for a greater realism in setting performance targets. PPARs are intended to focus on the performance of a single project to assess whether the individual investment was justified and whether it was implemented as planned. With this narrow focus, it is not surprising that the overall trends in the power sector of a country are not reflected. The present focus, however reduces the usefulness of the data which are available from the PPARs as it is difficult to get an accurate assessment over time of the power sector in individual countries in order to determine trends and causal factors. The statistical analysis of the Bank's historical involvement is becoming more difficult as the number of projects is increasing and the data become more difficult to retrieve and manipulate. It is recommended that greater attention be given to the collection and maintenance of a data base that will serve both audit and operational needs.

In addition to improving the accessibility of data, there is a need for a more consistent application of the OMS definitions of financial ratios as well as more attention given to quality control. In many cases, figures presented were ambiguously defined in documents and a full understanding of the situation was not possible.

The need for quality control of SARs also remains high. SARs are the principal document and used constantly throughout project implementation and provide significant information for the Borrowers and their consultants as well.

Specific recommendations for improving project and sector performance are summarized as follows:

1. systematically examine options for sector restructuring, in order to strengthen market forces, improve the environment in which the utility functions, and increase incentives for enhanced utility efficiency;

2. place greater emphasis on improving productive efficiency, with special reference to maintenance, rehabilitation, and distribution network investments, in order to improve losses and the quality of service; measuring productive efficiency can only be achieved by developing more systematic collection and analysis of performance indicators;

3. strengthen the analysis of power-energy-macroeconomic linkages, and pay more attention to project evaluation in the sectoral and national economic context. In particular, assess the feasibility of the sector investment program and the ability of the sector and government to finance the program;

4. in determining investment and pricing policy, adopt less deterministic analytical approaches that can better account for the greater uncertainties in the current environment. Also carry out a more in-depth risk and sensitivity analysis of the impact of poor project and

sector performance in the form of "what if" questions, as part of the financial evaluation to be undertaken during project preparation and as part of sector work (rather than at appraisal);

5. ensure that sufficient investment planning has been carried out to assess the relative importance of rehabilitation and reinforcement compared with generation and transmission capacity expansion. Maintain a balance in lending to ensure that all parts of the system can be uniformly developed;

6. adopt more realistic targets with respect to physical and especially financial performance, and identify more clearly and specifically the constraints to meeting such targets.

ANNEX I

SOURCES OF DATA FOR REVIEW OF POWER PROJECT AND SECTOR PERFORMANCE

A.1 Data Sources

About 300 projects have been financed by the World Bank and IDA (henceforth, reference to "World Bank" will include IDA projects) from 1965-83 of which about 95% were completed by the end of FY 1986. The year 1983 has been taken as the cut-off date in order to include in this review only projects that have been completed or have had at least three years of implementation experience. Altogether, data were collected from a variety of sources and analyzed for 123 completed projects approved mainly between 1967-1978 and implemented between 1967-1982. (See A.3 for list of projects). Data on projects approved in 1965 and 1966 and completed before 1972 were not generally available because project audit reports were only prepared for projects completed in 1972 and thereafter. The sources of data used in the study were project appraisal, completion and audit reports. (Henceforth, to simplify definitions the term "audit report" will be used throughout the study to include project completion reports which have not been audited but have been officially released from the Regions). Audit/project completion reports are available for 159 projects; however, time constraints, data anomalies, and other problems restricted the detailed analysis to 123 projects.

Data collection for the review was divided into two parts. The first part included compilation of data for several indicators, such as project cost overruns and delays, financial ratios, cumulative disbursements, sales and losses, and institutional performance for the 123 completed projects included in the study.

On the whole, the regional representation of the 123 projects is fairly good, with the exception of S. Asia (Table A1). The number of audit reports available for S. Asia is quite limited and is far below the actual percentage of total projects represented by that region. In particular, there are very few evaluations of completed Indian power projects, which is unfortunate in view of the severe financial problems which so many of the state utilities in India face today.

The second part of data collection focussed on (i) a sample of 50 projects randomly selected from the population of completed projects and (ii) a sample of 20 projects approved between 1979-1983, whether completed or not. For the first sample detailed information was obtained concerning reasons for cost or time overruns, financial and institutional performance and departure from sales forecasts, as well as on the level of government interference, selected financial indicators and tariff structures. Data from the annual Project Implementation and Supervision Review reports (PIRs) were used in this study to compare the results of projects in the 1980s with that of the 1970s. However, given the problems with PIRs (Section 3.2), an additional small sample of 20 projects was taken from those projects approved between 1979-1983 and under implementation during the 1980s. Most of these projects were not completed as of 1986, but there has been sufficient implementation time to compare appraisal expectations with actual results, particularly regarding project costs, time delays and financial performance. Most of the data was obtained from the latest supervision reports, except for the few cases where a project completion report was available. In addition, data was taken from EGY reports which reviewed ongoing projects (with data taken from supervision reports) on a periodic basis up until 1984.

In order to gain some indication of trends over a longer time span than the period under review, the findings of this study were compared with that of an OED study carried out in 1972. The OED study reviewed ten power companies which were the recipients of 39 Bank loans between 1950-1968. These loans represented about 40% of total power disbursements during that period. Most of the companies studied were by OED in Latin America but this was representative of the regional profile then prevailing, as about two thirds of power loans were made to Latin America during that period.

Other data sources from which limited data was drawn were the Energy Department 1982 Power Data Sheets, a book describing Bank experience in the power sector (mostly dealing with the Bank's policy and role in the power sector)[a], and a recent review of power sector performance indicators.

TABLE A1

Regional Comparison of Projects Approved and Number of PPARs During Study Period, FY1965 - 1983

	S. Asia	E. Asia	EMENA	W. Af.	E. Af.	LAC	Total
No: of projects approved	35	52	61	24	28	102	302
% of total	12	17	20	8	9	34	100
No: of PPARS	10	27	38	14	13	57	159
% of total	6	17	22	9	9	37	100
PPARs as % of total projects	29	52	62	58	46	56	53

a/ H. Collier, Developing Electric Power: Thirty Years of Bank Experience, Johns Hopkins Univ. Press, Baltimore, MD, 1984.

A.2 Quality of Data Sources

(i) Appraisal Reports

In general, the appraisal reports carried far more detailed information than did the audit reports. However, there were still some serious data gaps in the appraisal reports, especially the earlier ones. Disbursement schedules were not included until the early 1970s, therefore comparisons of projected and actual disbursements have not been made in the audits reports for the earlier projects. Details of proposed project financing were generally not given in appraisal reports until later in the 1970s and there was little reference to levels of overall investment program financing for the years leading up to appraisal; the latter could not even be estimated from source and application of funds statements since such statements generally referred to projections and included no details of funding over the past few years. Many of the appraisal reports did not include forecasts of such basic items as generation, losses, peak demand or installed capacity. Details of efficiency indicators such as consumers/ employee were also not included in many reports.

Despite the OMS guidelines on definitions of financial ratios, appraisals (and audits) are not consistent in the way in which such ratios are estimated. Furthermore, the definition of the ratio as used in the SAR (or PPAR) is frequently not given. The ratio with the most inconsistent definition from one report to another is the self-financing ratio, so that direct intercountry comparisons are not very meaningful. Most frequently, internally generated funds do not include any allowance for increases or decreases in working capital and often working capital increases are included in investment program requirements. If the adjustment is made to internally generated funds to allow for working capital changes, an originally estimated self-financing ratio of 15-20% can easily become negative.

Audit Reports

Project completion reports have been prepared for the majority of projects completed since 1972. Many of these projects have also been audited which means that OED has carried out its own review of the project. The findings of OED are included in an audit report which also includes the original project completion report.

Some of the problems encountered in using the audit reports as data sources are given below:

(i) actual financing of the project is often not given,

(ii) the extent to which the original investment program (of which the project was a part) was implemented is usually not given,

(iii) an assessment of the performance of the utility is often not given in any depth, especially regarding operations and maintenance and overall efficiency,

(iv) reasons for higher or lower than projected sales are not given in some reports,

(v) the adequacy of planning is not discussed in most reports,

(vi) lack of information on generation, losses, peak demand, installed capacity, reliability of serv[illegible] [illegible]nd breakdown of consumption at the time of project completio[illegible]

The earlier audits also contained no data sheets and no disbursement profile. Even such standardized data as financial statements are not included in all audits; for example, out of the 50 audits reviewed in the sample survey, seven had no balance sheets (which meant that receivables could not estimated) and five had no funds flow statements (which meant that the debt service and self-financing ratios could not be estimated, nor government contribution to construction). Implementation schedules broken down by project component were also absent from many reports.

Many of the audits for projects in certain Latin American countries compared appraisal and actual project costs in constant prices of the year of appraisal which is understandable in a situation of rampant inflation. However, in the comparison the reports have often not removed the price contingencies included in the appraisal cost estimates to bring those prices into constant terms. As a result, there is an underestimate of cost overruns in these cases.

A.3

List of Projects Reviewed in Global Sample of Project Performance

Loan/ Credit Number	Loan/ Credit	Audit Report Number	Region	Project Title	Board Approval Date
0118 GH	Credit	1568	WAP	Ghana - First Electricity Corporation of Ghana (ECG) Power	11-Jun-68
0165 IND	Credit	2741	AEP	Indonesia - First Electricity Distribution	21-Oct-69
0178 MAI	Credit	645	EAP	Malawi - Tedzani Stage I Hydroelectric	27-Jan-70
0213 PAK	Credit	3410	ASP	Pakistan - First WAPDA Power	12-Aug-70
0227 ES	Credit	862	LCP	El Salvador - Fifth Power	12-Jan-71
0242 IN	Credit	3006	ASP	India - Second Power Transmission	27-Apr-71
0286 EC	Credit	3003	LCP	Ecuador - Third Power	01-Feb-72
0334 IND	Credit	2741	AEP	Indonesia - Second Electricity Distribution	02-Jun-72
0372 CE	Credit	3711	ASP	Sri Lanka - Fifth Power	05-Apr-73
0377 IN	Credit		ASP	India - Power Transmission III	26-Feb-73
0386 JO	Credit	3875	EMP	Jordan - First Hussein Thermal Power	22-May-73
0399 IND	Credit	5104	AEP	Indonesia - Third Power	22-Jun-73
0405 BR	Loan	2370	LCP	Brazil - Estreito Power - Generation	25-Feb-65
0426 MAI	Credit	2116	EAP	Malawi - Second Power	04-Sep-73
0433 BO	Credit	2733	LCP	Bolivia - Third Empresa Nacional de Electricidad (ENDE) Power	29-Aug-73
0477 BR	Loan	858	LCP	Brazil - Power Distribution	13-Dec-66
0478 BR	Loan	858	LCP	Brazil - Power Distribution	13-Dec-66
0479 CH	Loan	1603	LCP	Chile - Fifth Power	22-Dec-66
0487 GU	Loan	625	LCP	Guatemala - First Power	19-Jan-67
0491 PH	Loan	980	AEP	Philippines - Fourth Power	04-Apr-67
0503 SI	Loan	749	AEP	Singapore - Power Distribution (Part I)	27-Jun-67
0511 PE	Loan	868	LCP	Peru - Matucana Power	07-Sep-67
0522 SU	Loan	1169	EAP	Sudan - Roseires Power	09-Jan-68
0537 CO	Loan	1654	LCP	Colombia - Third Expansion EEEB	28-May-68
0553 SL	Loan	1610	WAP	Sierra Leone - Second Power	30-Jul-68
0564 SU	Credit	5388	EAP	Sudan - Second Power*	22-May-75
0565 BR	Loan	2370	LCP	Brazil - Porto Colombia Power	15-Oct-68
0566 BR	Loan	1852	LCP	Brazil - Volta Grande Hydroelectric	15-Oct-68
0570 JO	Credit	3875	EMP	Jordan - Second Hussein Thermal Power	09-Jun-75
0572 IN	Credit	6307	ASP	India - First Rural Electrification	30-Jun-75
0574 CHA	Loan	1402	AEP	Taiwan - Tachien Power	26-Nov-68
0577 AR	Loan	1353	LCP	Argentina - El Chocon Power	17-Dec-68
0579 MA	Loan	774	AEP	Malaysia - Fourth Power	07-Jan-69
0591 IRE	Loan	1085	EMP	Ireland - Pumped Storage Power	18-Mar-69
0595 SI	Loan	749	AEP	Singapore - Power Distribution (Part I)	22-Apr-69
0596 ET	Loan	1102	EAP	Ethiopia - Finchaa Hydroelectric	06-May-69
0600 NEP	Credit	6177	ASP	Nepal - Kulekhani Hydro	23-Dec-75
0618 GH	Loan	1363	WAP	Ghana - Second Volta River Authority (VRA) Power	03-Jun-69
0627 AF	Credit	3496	EMP	Afghanistan - First Power	04-May-76
0631 CR	Loan	760	LCP	Costa Rica - Third Power	30-Jul-69
0636 CE	Loan	3710	ASP	Sri Lanka - Fourth Power	22-Jul-69
0644 AR	Loan	1055	LCP	Argentina - Third Servicios Electricos del Gran Buenos Aires (SEGBA) Power	07-Oct-69
0645 HA	Credit	3265	LCP	Haiti - First Power	17-Jun-76
0649 CY	Loan	819	EMP	Cyprus - Third Power	23-Dec-69
0659 ME	Loan	859	LCP	Mexico - Third Power Sector Program	24-Feb-70
0661 PAN	Loan	2508	LCP	Panama - Second Power (Bayano)	10-Mar-70
0671 CHA	Loan	1403	AEP	Taiwan - Second Power	21-Apr-70
0677 BR	Loan	2768	LCP	Brazil - Marimbondo Power	19-May-70
0681 CO	Loan	2720	LCP	Colombia - Chivor Hydroelectric	26-May-70

A.3

ist of Projects Reviewed in Global Sample of Project Performance

Loan/ Credit Number	Loan/ Credit	Audit Report Number	Region	Project Title	Board Approval Date
0684 LBR	Loan	1551	WAP	Liberia - First Power	28-May-70
0691 MAI	Credit	4859	EAP	Malawi - Nkula Falls II - Hydro	29-Mar-77
0700 MA	Loan	2644	AEP	Malaysia - Fifth Power	08-Jul-70
0701 ZA	Loan	4661	EAP	Zambia - Kariba North Hydroelectric	05-Jul-74
0715 TA	Loan	2765	EAP	Tanzania - Kidatu Hydroelectric (First Stage)	08-Dec-70
0716 IRN	Loan	3138	EMP	Islamic Republic of Iran - Tehran Power Distribution	27-Oct-70
0728 BR	Loan	2709	LCP	Brazil - Salto Osorio Hydroelectric	30-Mar-71
0734 SL	Credit	4525	WAP	Sierra Leone - Third Power*	12-Jul-77
0737 PNG	Loan	2687	AEP	Papua New Guinea - Upper Ramu Hydroelectric	15-Apr-71
0745 KE	Loan	1230	EAP	Kenya - Kamburu Hydroelectric	01-Jun-71
0749 CHA	Loan	2686	AEP	Taiwan - Third Power	21-Apr-71
0763 TU	Loan	3695	EMP	Turkey - TEK Power Transmission	15-Jun-71
0775 TU	Loan	1372	EMP	Turkey - Fourth Cukurova Power	29-Jun-71
0778 LBR	Loan	1551	WAP	Liberia - Second Power	22-Jun-71
0790 TH	Loan	1966	AEP	Thailand - South Bangkok Thermal Unit No. 4	26-Oct-71
0793 IN	Credit		ASP	India - Korba Thermal	18-Apr-78
0800 CR	Loan	2969	LCP	Costa Rica - Fourth Power	15-Feb-72
0804 IRE	Loan	2760	EMP	Ireland - Third Power	24-Feb-72
0809 PH	Loan	4388	AEP	Philippines - Fifth Power*	21-Mar-72
0829 BR	Loan	3500	LCP	Brazil - Sao Simao Hydroelectric	16-May-72
0831 CY	Loan	2259	EMP	Cyprus - Fourth Power	13-Jun-72
0834 ME	Loan	1775	LCP	Mexico - Fourth Power Sector Program	20-Jun-72
0836 YU	Loan	5113	EMP	Yugoslavia - First Power Transmission	13-Jun-72
0840 NI	Loan	5144	LCP	Nicaragua - Eighth Power and Earthquake Reconstruction (Part C)	27-Jun-72
0841 HO	Loan	5060	LCP	Honduras - Fifth Power	27-Jun-72
0847 UNI	Loan	5936	WAP	Nigeria - Fourth Power	29-Jun-72
0875 GUA	Loan	4621	LCP	Guyana - First Power	09-Jan-73
0887 BR	Loan	2708	LCP	Brazil - Power Distribution and Subtransmission	10-Apr-73
0889 ES	Loan	3053	LCP	El Salvador - Sixth Power	26-Apr-73
0919 ZA	Loan	5566	EAP	Zambia - Kafue Hydroelectric (Stage II)*	05-Jul-73
0936 MOR	Loan	4028	EMP	Morocco - First Power	11-Sep-73
0948 PAN	Loan	4246	LCP	Panama - Third Power*	27-Oct-73
0951 IC	Loan	3519	EMP	Iceland - Sigalda Hydroelectric	11-Dec-73
0977 TH	Loan	3999	AEP	Thailand - Ban Chao Nen (Srinagarind) Hydroelectric	02-Apr-74
0986 SYR	Loan	5290	EMP	Syrian Arab Republic - First Mehardeh Thermal Power	16-Apr-74
0997 AL	Loan	5194	EMP	Algeria - First Power	30-May-74
0999 PNG	Loan	3912	AEP	Papua New Guinea - Second Power	30-May-74
1028 RO	Loan	5838	EMP	Romania - First Turceni Thermal Power	05-Jul-74
1031 MA	Loan	3506	AEP	Malaysia - Sixth Power	04-Jul-74
1034 PH	Loan	4847	AEP	Philippines - Sixth Power*	02-Jul-74
1081 HO	Loan	5060	LCP	Honduras - Sixth Power	07-Jan-75
1126 CR	Loan	4991	LCP	Costa Rica - Fifth Power*	09-Jun-75
1144 SYR	Loan	5290	EMP	Syrian Arab Republic - Second Mehardeh Thermal Power	17-Jun-75
1147 KE	Loan	3505	EAP	Kenya - Gitaru Hydroelectric	01-Jul-75
1178 MA	Loan	6001	AEP	Malaysia - Seventh Power*	02-Dec-75
1194 TU	Loan	5304	EMP	Turkey - Second TEK Transmission*	18-Nov-75
1208 PAK	Loan	6004	ASP	Pakistan - Second WAPDA Power*	10-Feb-76
1215 PE	Loan	6125	LCP	Peru - Fifth Power Project	02-Mar-76
1238 BO	Loan	3715	LCP	Bolivia - Fourth Empresa Nacional de Electricidad (ENDE) Power	06-Apr-76

3

List of Projects Reviewed in Global Sample of Project Performance

Loan/ Credit Number	Loan/ Credit	Audit Report Number	Region	Project Title	Board Approval Date
1257 BR	Loan	5165	LCP	Brazil - Power Distribution (COPEL)*	11-May-76
1259 IND	Loan	5300	AEP	Indonesia - Fifth Power*	18-May-76
1288 ES	Loan	5399	LCP	El Salvador - Seventh Power*	17-Jun-76
1293 AL	Loan	5194	EMP	Algeria - Second Power	22-Jun-76
1300 BR	Loan	5993	LCP	Brazil - Northeast Power Distribution*	24-Jun-76
1301 PO	Loan	4294	EMP	Portugal - Sixth Power*	24-Jun-76
1306 TA	Loan	4622	EAP	Tanzania - Kidatu Hydroelectric (Second Stage)*	01-Jul-76
1343 BR	Loan	5695	LCP	Brazil - ELETROSUL Transmission	23-Nov-76
1351 CH	Loan	5547	LCP	Chile - Sixth Power*	21-Dec-76
1365 IND	Loan	6238	AEP	Indonesia - Sixth Power	01-Feb-77
1380 GH	Loan	5731	WAP	Ghana - Kpong Hydroelectric (VRA)	22-Mar-77
1381 GH	Loan	5731	WAP	Ghana - Third ECG Power Distribution	22-Mar-77
1442 OM	Loan	4245	EMP	Oman - Engineering for Power and Urban Water Supply*	18-May-77
1443 MA	Loan	6241	AEP	Malaysia - Eighth Power	02-Jun-77
1453 EGT	Loan	5110	EMP	Egypt - Regional Electrification	09-Jun-77
1469 YU	Loan	5390	EMP	Yugoslavia - Second Power Transmission*	28-Jun-77
1531 SYR	Loan	6007	EMP	Syrian Arab Republic - Regional Electrification*	14-Mar-78
1547 PH	Loan	5732	AEP	Philippines - First Rural Electrification	04-Apr-78
1549 IN	Loan	6253	ASP	India - Third Trombay Thermal	19-Jun-78
1603 LBR	Loan	4614	WAP	Liberia - Fourth Power	15-Jun-78
1629 HO	Loan	5420	LCP	Honduras - Nispero Power	04-Nov-78
1688 JO	Loan	5172	EMP	Jordan - Third Power	12-Apr-79
1770 TH	Loan	6157	AEP	Thailand - Khao Laem Hydro	27-Nov-79
1873 CY	Loan	5992	EMP	Cyprus - Fifth Power	12-Jun-80
2045 EC	Loan	6359	LCP	Ecuador - INECEL Power Transmission	21-Jul-81

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