GOVERNMENT OF INDIA
MINISTRY OF POWER

सत्यमेव जयते

Conference on Power Sector Reforms in India

Jaipur, India
October 29-31, 1993

Cosponsors:
Government of India, Ministry of Power
World Bank India Department
ESMAP

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ESMAP
Energy Sector Management Assistance Programme

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) was launched in 1983 to complement the Energy Assessment Programme, established three years earlier. ESMAP's original purpose was to implement key recommendations of the Energy Assessment reports and ensure that proposed investments in the energy sector represented the most efficient use of scarce domestic and external resources. In 1990, an international Commission addressed ESMAP's role for the 1990s and, noting the vital role of adequate and affordable energy in economic growth, concluded that the Programme should intensify its efforts to assist developing countries to manage their energy sectors more effectively. The Commission also recommended that ESMAP concentrate on making long-term efforts in a smaller number of countries. Today, ESMAP is conducting Energy Assessments, performing preinvestment and prefeasibility work, and providing institutional and policy advice in selected developing countries. Through these efforts, ESMAP aims to assist governments, donors, and potential investors in identifying, funding, and implementing economically and environmentally sound energy strategies.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and institutions providing financial support, and representatives of the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Finance and Private Sector Development, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. ESMAP is staffed by a cadre of engineers, energy planners and economists from the Industry and Energy Department of the World Bank. The Director of this Department is also the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information or copies of ESMAP reports, contact:

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Preface

Many developing countries and formerly centrally planned economies are considering efforts to restructure their energy sectors as part of their overall economic transformation. In most of these countries, the power sector comprises the largest single group of public entities operating as natural monopolies, and, consequently, it has been a focal point of attention with regard to reform.

In October 1992, the World Bank's India Region Energy Operations Division assisted India in carrying out a workshop in Goa, "Implementation Issues in the Power Sector," during which participants noted that in the absence of an enabling framework for private participation in the power sector, and without clear "rules of the game" and well-established principles and processes for restructuring and regulation, it would be very difficult to promote further private investment. Following up on the interest manifested at one Goa workshop and several other meetings, India's Ministry of Power, with the assistance of the World Bank's India Department and the Energy Sector Management Assistance Programme (ESMAP), began preparations in early 1993 for a large-scale conference on institutional policy and regulatory reforms and the international experiences relevant to the Indian context.

The conference would allow senior Indian officials to examine and discuss alternative models of sector organization and the restructuring experiences of other countries that could assist them in their own efforts to plan and implement appropriate reforms for the Indian power sector. By assembling high-level central government officials, electricity supply industry operators from state governments and private power utilities, end-users, representatives of policy think-tanks, and others, the conference would serve as a forum for informed and productive debate on the various sector issues and reform options among the diverse participants. In particular, the participants would be able to (a) share their diagnoses of the problems typical of India and other developing countries, (b) review the experience of countries that have reformed their power industries, (c) examine the options most suitable to India, and (d) define an appropriate course of action.

The conference took place on October 29-31, 1993, in Jaipur, and is expected to be part of a series of discussions that will accompany the reform process. This volume includes the

Keynote Address on State Electricity Boards by Shri Sharad Pawar, Chief Minister, Maharashtra, and Chairman, NDC Committee on Power, and the papers presented and commissioned for the conference, as well as capsule summaries of the main points of debate. The reader is cautioned that the draft background papers provided by the authors have not been subjected to extensive review and revision. We hope that timely dissemination of the proceedings of the conference will help to sustain its momentum and the resolve manifested by the participants to pursue effective and appropriate reforms in the sector.

The conference was made possible by the close collaboration of the government of India with the World Bank and ESMAP. Special thanks go to Mr. R. Vasudevan, Secretary, Ministry of Power, and Mr. A. Dua, Joint Secretary, Ministry of Power (Conference Director). On the part of the World Bank, the work was jointly managed by Luis E. Gutiérrez (IENPD) and Djamal Mostefai (SA2EG), supported by a core team consisting of Alfonso Mejía and Mohinder Gulati (India Resident Mission). Manju Malik (EDI), Jose Escay, Ernesto Cordova, and the Visiting Mission Support Unit (VMSU) of the World Bank Resident Mission provided the logistical support, with the invaluable help of personnel from the Indian Ministry of Power, National Hydro Power Corporation, the Rajasthan State Electricity Board (SEB) and the World Bank Resident Mission in New Delhi.

Funding was provided by the Swedish government, through its bilateral aid agency, SIDA, and the World Bank.

We wish to express our appreciation to the government of India, the many enterprises and organizations in the power sector, and especially to Mr. R.C. Dave, chairman of the Rajasthan SEB, for the cooperation and assistance rendered to the World Bank and ESMAP staff during the organization and development of the conference.

Executive Summary

India's electricity supply industry (ESI) is facing numerous difficulties. Despite considerable investment and expansion of generating capacity over the last decade, the operational efficiency, quality, and reliability of electricity supply have deteriorated steadily. This deficiency is evidenced in the fact that the ESI, with a nominal installed generating capacity of 70,000 MW, is unable to meet reliably a peak demand of only 43,000 MW. In 1991-92, energy and capacity shortages averaged from 9 to 18 percent of the estimated demand. This situation is expected to worsen in the future. The initial target for the Eighth Plan was to increase generating capacity by 30,500 MW, with the private sector to provide about 2,800 MW. But the likely achievement is about 20,000 MW because of public resource constraints and a slower-than-expected pace of participation by the private sector.

As it now stands, India's ESI cannot mobilize the resources required for its development. Almost all power utilities, particularly the State Electricity Boards (SEBs), are in financial distress. Few of the SEBs turn a profit. In recent years, the commercial losses of SEBs have been increasing; currently, they exceed $1 billion per year and place a heavy burden on the public budget. One of the main problems is that electricity has for long been priced below its costs, leading not only to the financial distress of SEBs but also to overblown demand, cross-subsidies, and higher generation requirements. Typically, the SEBs' tariffs are equivalent to only 50 to 60 percent of long-run marginal costs. The agriculture and domestic sectors have been the main beneficiaries of this tariff policy. Given the fiscal situation, both the national government and the states acknowledge the need to raise power prices to economic and financial levels. Yet movement toward cost-recovery pricing has been hindered by a long-standing view that electricity is a social benefit and development tool rather than a service to be bought and sold commercially.

To overcome the financial gap, India counted on a substantial increase in local and foreign private participation. The 1948 Electricity Act was amended in 1991. Yet despite the new legislation, the contribution of private power utilities is likely to remain limited because of the lack of an enabling environment for participation by the private sector. That is, private investors still perceive as unacceptable the risks and costs (including transaction costs) represented by the

existing institutional and regulatory framework and the financial weaknesses of the SEBs, and this in turn has prevented most potential power investments from going beyond initial expressions of interest.

The government and the World Bank agreed that a conference on power sector reform would be an appropriate first step to assist India in bringing progress on the above issues. The main objective of the conference was to expose senior Indian officials to the alternative sector models and the restructuring experiences in other countries, and in that way to assist them in planning and implementing appropriate reforms for the power sector, especially at the state level.

The conference consisted of an opening session, four topical sessions, and a summary of the lessons learned and the key elements needed to continue examining the potential for power sector reform in India. The four topic sessions covered (a) the need and conceptual framework for power sector reforms in India; (b) challenges faced by the SEBs; (c) four country case studies; and (d) commerciality of the SEBs and design of the reform process.

Some of the salient points brought out at the conference were as follows:

- *The Indian power sector will not be able to meet the investment challenges unless structural changes are undertaken to enable it to perform on a sound commercial footing.* Without drastic measures, the current power gap is likely to widen in the future, possibly reaching some 25 percent of peak demand by the year 2000.
- *As it stands, the Indian power industry is unable to mobilize the resources required for its development.* Almost all power utilities, particularly SEBs, are in financial distress, placing a heavy burden on the public budget.
- *The availability of financial resources from the private sector will be linked to the pace and depth of the reform.* Under the best of circumstances, private savings will be slow to materialize until confidence and experience are gained.
- *A major deficiency in the present system is the lack of commercial autonomy for the SEBs.* The managerial and financial autonomy of the SEBs has significantly eroded as a result of continued political interference in day-to-day managerial matters (tariffs, recruitment, extension of distribution systems, etc.).
- *The experiences of Argentina, China, the United Kingdom, and the United States provide some useful lessons on how different reform processes can be conducted, and an understanding of these experiences may be of significant value for those who are working at reforming India's power sector.* Conference papers described various reforms and the key features of the new institutional and regulatory structures and highlighted (a) the reform process (why and how it begun, how it was done, who were the main players); (b) the influence of macroeconomic reforms (how conducive were they to reforms in the power sector); (c) the issues and obstacles faced during and after the reform; (d) the main sector issues and options; and (e) the tangible results achieved.
- *Sector reform is a political process, requiring a new social pact between enterprises, government, and consumers.* It will require a coordinated effort to deal with the interrelated issues of markets, institutions, regulation, and finance.
- *A rapid pace of reform may be critical for its success.* Depending on political circumstances, a slow and overdeliberate pace of reform may encourage much opposition and produce few benefits. That is, a protracted reform may be more institutionally challenging than a bolder program of change.
- *Regulation is a key factor in power sector reform.* Regulatory reform needs to march in step with sector restructuring and introduction of private sector participation. In the United Kingdom and the United States, an emphasis on explicit, independent regulation has promoted reform, albeit in somewhat different ways in each case. The emphasis in independent regulation is on price, quality of supply, and consumer protection more than on the regulation of supply and investment.
- *SEBs can supply electricity of appropriate quality at competitive prices only if they can function as commercial entities.* Commerciality implies the ability to (a) meet power needs efficiently; (b) make decisions without external interference, along commercial principles; (c) meet all financial obligations to the suppliers of inputs and power; (d) generate enough revenues to fund a significant share of their investment programs and fully meet debt servicing and debt redemption obligations; and (e) raise

commercial finance and the freedom to contract power supply from the lowest-cost producer.

- *The solution to the sector's problems lies in effecting structural, institutional, and regulatory reorganization along market lines, opening the sector to competition where possible (i.e., in generation and marketing of electricity), and providing arm's-length regulation in the remaining areas, as a prelude to implementing other financial reform measures.* These reorganizations should aim at strengthening the financial and managerial autonomy of the SEBs while enhancing competitive conditions in the sector. This involves (a) properly demarcating the relative roles of central and state governments in power sector management, based on the managerial and financial autonomy of power utilities; (b) empowering SEBs to adopt different options for generation, transmission, and distribution; (c) corporatizing SEBs and opening sale of equity to all stakeholders, especially to power consumers; (d) deregulating the power market for large high-tension consumers; (e) organizing regional power pools; and (f) restructuring the regulatory mechanism to encourage a transparent and autonomous regulatory process.
- *Electricity has become a basic necessity for modern living, but social policies must be clearly separated from commercial activities.* The state governments have often implemented social subsidy policies through the SEBs, thereby compromising the financial viability of the Boards. In practice, thus, the Boards have found vital commercial subjects such as tariffs, new connections, and disconnections beyond their purview, and this has kept them from operating on a fully commercial basis. The state and central governments thus need to develop a workable mechanism to protect vulnerable consumers without compromising the Boards' abilities to function on commercial terms. In view of the growing size of the power sector, the need for transparency in operations is urgent.

The broad thrust of the conference, as it appeared to the World Bank's closing speaker, was to propose an agenda that would promote corporatization of generation, transmission, and distribution of electric power; align tariffs with costs of supply; foster competition where possible and implement regulation where not; effect bold state-level reforms to encourage commercialization of the sector; and put in place financial and accounting improvements to manage the fiscal impact of the reform.

Vigorous and effective implementation of such a comprehensive program of reform, the speaker suggested, would provide the basis for substantial short- and medium-term financial external support for priority investment programs in the power sector, including further development of renewable energy sources, stepped-up dissemination of demand-side management techniques; increased support for promoting environmentally more sustainable operation of India's existing and new generating capacity; and forward-looking use of financial guarantees and cofinancing to give the stronger, more solvent elements in the sector better access to well-funded capital markets inside and outside India. Further high-level conferences to assess progress and discuss challenges along the reform path would also have merit, the speaker concluded.

Keynote address on state electricity boards: issues and options

by
Shri Sharad Pawar
Chief Minister, Maharashtra
Chairman, NDC Committee on Power

Shri Salveji, Union Minister of Power, distinguished guests, and friends,

At the out-set, I would like to thank Shri N.K.P. Salve, Union Minister of Power, for having invited me to this Conference on Power Sector reforms in India and to share my thoughts with you. In today's world, electricity is probably the most vital input for economic development. On attaining independence from colonial rule in 1947, India took several steps to establish a power network throughout the country. This sector was given a lion's share of the plan outlays in successive Five-Year Plans (FYP) of the country. However, in spite of the impressive growth that was achieved in the sector, power supply interruptions, power shortages, and poor voltage conditions are common throughout the country. This has a major adverse effect on both the agricultural and the industrial sectors and the nonavailability of power is likely to be the single most critical constraint to development in the coming years. This was recognized at the meeting of the National Development Council (NDC) held in April 1993 and it was decided to constitute a committee on power to suggest measures to reform this important sector. The committee has since been appointed under my Chairmanship and we will shortly present our report. I am, therefore, particularly happy to be amongst you today when you are examining the challenges facing the power industry in India and discussing reforms needed to address these challenges. I would like to congratulate the Union Ministry of Power, Government of India, for organizing this conference with the assistance of the Joint UNDP/World Bank Energy Sector Management Assistance Program and the India Department of the World Bank. I am told that, in the conference, some foreign experts will present the lessons of power sector reforms in different countries and compare the Indian power sector in the context of the other large-scale power systems around the world. This conference will thus give an opportunity to the power sector in the country to get an overview of the alternative power sector models and the restructuring measures adopted by other countries. We are at a critical juncture when we expect the power sector to undergo major changes and achieve a momentum that is required to meet the needs of a fast-developing economy. The conference is, therefore, timely and as the Chairman of the NDC Committee on Power as well as the Chief Minister of Maharashtra, I look forward to the conclusions of this conference.

1. Background

During the British Colonial rule, the emphasis was on the continuance of the colonial rule. There was hardly any economic development during this period except that which met their own purpose. This is clear from the fact that in 1947 the total installed generation capacity in the country was only 1,362 MW. This has gone up to 72,319 MW in March 1993, registering an increase of over 53 times. The actual generation of power rose from 4.1 billion units in 1947 to 301 billion units in 1992-93, representing an annual growth rate of about 10 percent. About 489 thousand villages constituting 85 percent of the total number of villages in the country have been electrified as against 3,000 at the end of 1950. The number of agricultural pumps that have been energized in the rural areas is more than 10 million. All these impressive achievements could be possible largely through the State Electricity Boards (SEBs) and the heavy investments made by the governments in the public sector. Such a massive expansion, particularly in far-flung, remote rural areas would not have been possible but for the important role played by the SEBs.

2. Introspection

However, it is time to pause and to reflect whether this achievement has been sufficient. If we take into account the growth of the population, the vast changing needs of development, and the rising expectations of the people, the answer to this question must, regretfully, be in the negative. By the end of 1991-92, the all-India average energy deficit in the power sector was of the order of 8.5 percent with a peaking shortage of 17.7 percent. The projected electrical energy demand by 1996-97, i.e. by the end of the Eighth FYP, is expected to be 416 billion units. Taking into account the expected capacity additions by various sectors of only around 31,000 MW until 1996-97, the energy shortage at the end of the Eighth FYP would still be 4.2 percent and the peaking shortage would have risen to 18.4 percent. More important is the quality of supply that we will be giving to the consumers, who will be facing interruptions, poor voltage conditions, and power cuts. In order to find answers to all these questions, we must try and analyze some of the reasons for the problems that we face today. I would like to dwell on some of these issues now.

3. Technical improvements

A major deficiency in the present system is the managerial weakness leading to low technical achievements of the SEBs. The plant availability, the plant load factors, the heat rates, and the levels of auxiliary consumption of many plants in the country today are much below the norms. In some states, the plant load factor is as low as 25 percent to 30 percent and auxiliary consumption as high as 15 percent to 20 percent. The specific oil consumption varies between 3 to 5 milliliters per unit in the more efficient states and 23 to 24 in others. In many power plants, the normal maintenance works are also not being carried out properly and repairs and renovations of existing old plants not attended to in time. It is, therefore, imperative that more attention is paid to improve the performance by adopting better operational methods, planned outages, and proper use of spares and manpower.

Considerable expenditure is also incurred in transportation of coal with high contents of ash and other material. It is essential to set up coal beneficiation plants at the coal mines immediately to reduce this expenditure and to improve the performance of the existing generating capacity. This will also reduce the wear and tear of the equipment at the power stations.

4. Transmission and distribution losses

The most disturbing aspect of the Indian power scene is, however, the high transmission and distribution (T&D) losses which are at present around 23 percent. In some states, these are as high as 42 percent, while in many of the major

states, these are around 25 percent. Since most of the states have unmetered supply of electricity on the basis of HP block tariff for the rural agricultural pumps, a considerable quantum of energy may get adjusted on this account. It is, therefore, a moot point as to whether even the T&D losses shown at the present are a correct indication of the actual energy which is lost or unpaid for. One major reason for these losses is the technical losses. This can be set right only by strengthening the system through more substations, installation of capacitors, and increasing the ratio of high-tension (HT) lines to low-tension (LT) lines. This requires considerable investments and financial support to the Boards. However, very often we tend to distribute our resources thinly over a wider area, in our anxiety to reach as many areas and consumers as possible, rather than concentrating on spending the resources more judiciously. A more important reason for the losses is commercial, i.e. theft of energy. A large number of consumers from all sectors, whether industrial, commercial, domestic, or agricultural, do consume electricity without paying for it. Unfortunately, many a time, this is done with the collusion of the staff of the Electricity Boards. Such theft of energy not only affects the financial position of the Electricity Boards, making them ineffective in many areas, but also hurts the honest consumer as he gets a deteriorated supply with low voltage and interruptions and also has to pay more for the power. This organized theft of energy needs to be checked immediately else it will not only destroy the entire power sector in the country, but will also destroy the moral fabric of the society. Some half-hearted measures of policing and setting up of vigilance units have been taken up by many of the SEBs. While acknowledging the need for introducing strong punitive measures in dealing with such thefts, the importance of a systematic effort in accounting of energy right unto the subdivisional level in the SEBs needs hardly to be stressed. This will help in keeping a proper account of the use of energy and help identify areas needing constant vigil. I would strongly urge the introduction of Energy Audits which has been undertaken by some SEBs in the country. Meters need to be installed at the substations to measure the outflow of electricity through every feeder. The readings from these meters should be cross-checked with the readings obtained from the consumers in that area and the explicit losses worked out in the subdivision. A system of accountability needs to be introduced in the field and the person in charge of the smallest area made answerable for all the energy which flows through his area. Suitable methods could be introduced to ensure constant vigilance and supervision of the connected load and energy consumption of major consumers in the area to check for correctness. Computerization of the energy billing system can greatly help in creating a large database of commercially valuable information and provide excellent inputs for effective energy audit. All-out efforts to compute the rise in the energy billing for HT and LT industrial consumers, commercial consumers, and residential consumers in that order, need to be taken and the computerization completed in a time-bound manner. Along with this, installation of efficient meters which cannot be tampered with as well as cross-checking and monitoring of meter readings of commercially important consumers by superiors needs to be introduced. The entire structure of the SEBs needs to be decentralized and every small unit, right up to the level of subdivision, made accountable for the energy received and sold by it as well as the revenue earned and expenditure incurred by it. The staff and management of the Electricity Boards will have to imbibe a new work culture if we are to obtain better results. Perhaps, if the message goes out that the very survival of the Electricity Boards and the jobs therein are at stake, the introduction of this work culture would be easier.

5. Financial outlay

Another important reason for the SEBs not being able to render the expected level of service is the inadequate annual financial outlays. Electricity is a costly business and huge investments are required for generation, transmission, and distribution. In spite of the best of intentions, it has not been possible for many of the state governments to provide adequate money for this purpose in view of the competing demands from other sectors. A significant burden of setting up generating capacity has been taken by the central sector corporations such as National Thermal Power Corporation (NTPC), Nuclear Power Corporation, National Hydroelectric Power Corporation, etc. In order to further lighten this burden and in response to the Government of

India's policy, most of the SEBs have started negotiations with the private sector to set up independent generating facilities. The Powergrid Corporation of India is also setting up major transmission lines in different parts of the country and thus, reducing the burden on the states. The states can, therefore, concentrate on the distribution schemes and a major share of the budget could be earmarked for this area which has been comparatively neglected so far. The strengthening of the distribution system will reduce losses and provide better service to the consumers.

In the past, state governments have been providing money to the SEBs largely by way of interest-bearing loans which have to be fully repaid. While the terms and conditions of these loans were comparatively soft at the beginning, they became more difficult in later years. As a result, many of the Boards have to bear a heavy burden of interest and repayment of loans every year. In some states, the amounts which the Boards have to pay are so high that they exceed the annual budget which the government provides every year. A number of State Boards have, therefore, made a suggestion that the state governments convert at least part of these loans into equities so as to reduce the financial burden of the Boards.

6. Tariff policies

In order to understand the working of the SEBs, it is important to understand the tariff policies followed by them. As per the Electricity Supply Act, the SEBs have the power to fix their own tariffs. However, because of its diverse implications, in practice, the state government does have an important say in the tariffs to be levied. The proposals are generally initiated by the Boards on a cost plus basis and the state governments take decisions on the basis of the existing situation and the likely impact that the tariff will have on the various sectors of consumers. I feel that both these ingredients of tariff structure are imperfect. The cost plus basis of tariff only increases inefficiency and burdens the consumers with high rates. The Boards need to reduce their costs, work on efficient lines, and be made answerable to some authority for any increase in the tariffs. Also, while tariff is too important a matter to be left to the SEBs, at the same time the state governments should also not take decision on tariff purely for political expediency. A sound commercial view needs to be taken while revising tariff which will take a realistic stock of the cost, reward efficiency, and protect the consumer. I understand that the Government of India has taken a decision on the constitution of National and Regional Tariff Boards to go into the question of tariffs. This is a welcome step and I hope they will start functioning early.

At the present, in most of the states, the tariff for the domestic and agricultural consumers is subsidized and higher rates are charged to the HT industrial and commercial consumers. The agricultural consumers particularly have been subsidized heavily and are charged on block tariff based on horsepower instead of metered tariff. Some of the states have gone to the extent of giving electricity to the agriculturists free of cost. I am of the opinion that subsidy to some extent for both the sectors is unavoidable. The encouragement given to the agriculturists has resulted in the installation of more than 10 million agricultural pumps in the country leading to increased agricultural production. In my state alone, more than 1.7 million pumps have been installed which has resulted in a dramatic change in the countryside. Many of the farmers have gone in for second or third crops or are producing cash crops like sugar cane and oil seeds. This increased production and prosperity in the rural areas could not have been possible without the conscious policy of subsidizing the energy cost of the farmers. The domestic consumers, particularly of the lower slabs, also require certain subsidies. I, however, differ regarding the extent of subsidies to be given. Fixing very low tariff unrelated to the cost of electricity, or worse still, giving it free of cost, is counterproductive. This results in casting an unduly heavy burden on the other consumers who have to cross-subsidize the cost of electricity. It also results in indiscriminate waste of electricity and use for unproductive purposes. Subsidies to the consumers should, therefore, be related to the cost of electricity and revised from time to time.

In many states, due to the extent of subsidies and the lack of adequate cross-subsidization, the SEBs run into major financial difficulties and are often unable even to get the minimum statutory return of 3 percent on their net fixed assets. At such times, it is imperative that the state governments should step in and provide the necessary subsidies to the SEBs in time. However, this is

often not forthcoming and the SEBs are left to manage their own affairs as best as they can. I think, in such cases, the state governments are avoiding their responsibilities as the SEBs are merely following a policy laid down by them. I would personally prefer that subsidies are so fixed that the SEBs are self-sufficient with a certain degree of cross-subsidization and do not have to come to the state governments for assistance; however, where this is not possible, the state governments must compensate the SEBs in time.

7. Commercial working of the Boards

While the SEBs have played an important role in the past, it is vital that they re-orient their working on commercial lines if they have to have any role in the future. The country just cannot allow the Boards to run with inefficient management and unsound commercial principles. The management needs to be given a free hand to run on commercial lines and made accountable for any failure. I would like to give a few examples to illustrate this point:

- Most of the SEBs hardly pay attention to project delays and cost overruns. Very few projects get commissioned in time and within the budgeted cost. Between the starting of the project and its commissioning, many of the officers are transferred or retire and very often, it is very difficult to fix responsibility for the lapses even if an attempt is made to do so. Some way has to be found out to make the concerned persons responsible for implementation of the projects in time and within the budgeted cost.
- Another example would be that of timely meter reading and billing to the consumers. In many of the SEBs, not only is this work neglected and left to be decided at a lower level, but many a time, average bills are issued and that too after a lapse of several months of consumption of the electricity. This results not only in complaints from many consumers and dissatisfaction all over, but also loss to the Board as a large part of the money remains locked. Similar is the case of purchases of material and equipment. The SEBs need to be vigilant about the quality of equipment and certain rigid standards as well as inspection procedures require to be laid down. The system of purchases on the basis of lowest quoted tender along with the policy of protection to certain types of suppliers needs to be studied carefully and revised if necessary.

I would urge that the message of the need to have the SEBs run on commercial working requires to be stressed at all levels, from the chairman to that of the lineman. Unless a sense of awareness is created that the government is serious about this step and will not tolerate inefficiencies, no improvement will be possible. Where there is no such change, I would even propose that not only the persons be changed but the monopoly of the SEBs ended and they be reorganized or new parties allowed to come in the area to provide competitiveness and alternate service to the consumers.

8. Private sector

That brings me to the role of the private sector in the field of energy. This is not a new concept in our country. As far back as 1915, Tata set up a hydro power station to supply electricity to Bombay. In several parts of the country like Bombay, Calcutta, and Ahmedabad, we have private electricity companies providing electricity to the consumers. We have already consciously decided to promote the role of the private sector in the field of energy especially in the field of generation. This will not be in lieu of the SEBs, but to support them. We have to set up substantial generating capacity and a transmission-distribution network in the shortest possible time. The state governments just do not have the money and the time to do the job in the traditional way. Most of the SEBs are already negotiating with several foreign and domestic private companies for the establishment of this new capacity. This should be expedited and clearances from the central agencies granted on priority. Each state will have to decide its own plan of action depending on its geographical location, its requirements, and the capacity of its Electricity Board. Hence, some would go for

private hydro capacity, some for thermal, and others for imported fuel. Some SEBs would give distribution to the private sector, others may go in for wheeling and banking, while some may restrict the private sector only to generation. However, it is important that early decisions are taken in this regard and the Government of India actively help in guidance and early clearances.

Along with this initiative, we should also actively take up cogeneration in whatever way we can. Cogeneration, especially where there is waste heat or where there is bagasse, as in sugar factories, would be a major fuel saving area for the country. There is tremendous untapped potential in this area. Certain modifications in the existing equipments and some investment for new machines will generate substantial energy at a much lower cost than a new power station. We need to promote this sector and give it all the assistance especially regarding the availability of finance and technical know-how. Other nonconventional sources of energy such as wind, solar, etc., also need to be pursued. The SEBs should offer to purchase all the power from such units at a negotiated remunerative price.

9. Energy conservation and demand side management

Last but not the least, I would like to emphasize the need to conserve energy. Energy saved is more than energy generated and so this is the cheapest form of energy. Unfortunately, in our country, many of our appliances and equipment are not energy efficient. Minimum energy efficiency standards need to be laid down and the consumer made aware of these. The consumer requires to be educated on the high costs of producing energy and the need to use it efficiently and economically. The SEBs particularly face problems of meeting power requirements during peaking hours. For this purpose, time-of-day metering needs to be introduced so that some consumers at least find it economical to divert a part of their load to the off-peak hours.

10. Conclusion

To conclude, I would like to stress once again the urgent need to radically change our power scenario. Unless we transform this sector to meet the growing challenges of development and the aspirations of our people, we will be left far behind in the race amongst the nations. We have undertaken an ambitious program and it is important that we should not lose any momentum while making these changes. I am sure that the power sector will rise to the occasion and achieve the desired goals.

International power sector experience: A comparison with the Indian power sector

by
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1. Introduction

Comparisons of any kind are always difficult, full of exceptions, and weakened by various shortcomings. But they are the only effective way to judge relative performance. This paper compares the power systems of several countries with that of India. Its main purpose is to provide a frame of reference for understanding the many challenges facing India's system.

The countries included in the comparison were of several types and include both developed and developing countries, ones with vertically integrated monopolies and open-competitive systems, and ones with public and private utility systems. Among the countries selected, some have fully developed electricity supply industries (ESIs), such as the United States, the United Kingdom,[1] Norway, and New Zealand, whereas others, such as Turkey, Chile, and Argentina have developing systems. Still others, such as the People's Republic of China, Indonesia, Pakistan, the Philippines, and Thailand, were selected for intraregional comparison with India. This cross-sample thus should help illustrate how the Indian power sector compares with several types of systems:

- *Developed systems,* to see how India may need to change to attain higher performance;
- *Developing systems,* to examine the breadth of challenges these countries face;
- *Reformed or reforming systems,* to assess how reforms affect performance;
- *Neighboring systems,* to assess how India is doing in comparison with other Asian countries.

1.1 *Sample of countries*

The first subset of countries comprises developed countries with market-based ESIs. Among these, the United States has the world's largest ESI,

[1] The power sector in the U.K. comprises the two systems of England and Wales (E&W) and that of Scotland. In this paper, reference to the U.K. system means only the E&W system.

comprising both publicly and privately owned utilities. The country has developed a comprehensive regulatory system for monitoring prices and performance and has recently implemented a series of innovative mechanisms in pricing, transmission, and the environment that reflect an evolutionary path toward reform. Also in this subset is the U.K., which has a large, primarily coal-based system (similar in this respect to India), with significant hydro and nuclear generation. The U.K.'s power sector was recently transferred from public to private ownership and put under regulatory and pricing mechanisms designed to foster and sustain high levels of efficiency through competition. Hence, the U.K.'s path to reform was relatively rapid and radical. Norway has also recently implemented far-reaching reforms involving unbundling of generation, transmission, distribution, and marketing of electricity, but without drastic changes in ownership; nonetheless, the reform has led to extensive competition in the sector, facilitated by a profound change in government attitudes—reflected in the Energy Act, which explicitly recommends that competition replace politically administered control—that has allowed greater deregulation and more competition. The last in the developed-country subset is New Zealand, which has also begun reforming the power sector to increase competition and increase flexibility in the ESI.

The second subset represents diverse developing countries. As a laboratory of market-based reforms and privatization of natural monopolies, Chile has the "oldest" of the "newest" ESIs. Also in this subset is Argentina, which experienced a serious financial and operational crisis in the power sector during the 1980s that prompted a major restructuring effort. Although it may be too early to draw definitive conclusions, Argentina's experience is suggestive for India because our data for Argentina comprises 1990-91, when the sector was still in crisis, as India's is today, and it appears from current data that the reforms have led the sector out of crisis. Turkey, the last country in the subset, has a traditional ESI with a vertically integrated monopoly. Like India, Turkey is considering alternative institutional models for the ESIs and, despite significant build-operate-transfer efforts, has a poor record in attracting private investment.

The third subset includes China (People's Republic), Indonesia, Pakistan, the Philippines, and Thailand. These Asian countries are at various stages in developing and reforming their power sectors and in addressing the long-term obstacles to achieving competitive ESIs and sustainable growth.

Although the structures of the ESIs and the overall energy sectors of each country are quite different, the data have been aggregated to the extent possible on a countrywide basis. The data focus on the period from 1980 to 1991, where possible. The data have been collected thanks to the efforts of several people and institutions[2] and from publicly available sources.[3]

1.2 Sector indicators and methodology

Most of the power sector data extends through 1991, except for Indonesia, Pakistan, the Philippines, and Thailand, for which 1990 was the latest year information was available. The information and indicators assembled include the following:

- Country background, sector policies, and institutional framework;
- Supply performance:
  - Capacity and generation growth;
  - Use of transmission and distribution (T&D) systems;
  - Station use and losses;
  - Peak demand and reserve margins;
  - Power and energy shortages;
  - Environmental performance.
- Demand indicators:
  - Demand growth and structure;
  - Electricity customers;
  - Tariff levels and structure;
- Productivity indicators:
  - Labor productivity;
  - Power station performance;
- Financial challenges:
  - Investment needs;
  - Cost and revenue performance.

Given exchange rate distortions, value comparisons may be misleading, especially for nontradables and domestic prices. Hence, in the price comparisons we have used World Bank purchasing power parity exchange rates (PPPERs) that take account of the international differences

[2] This data base was put together with the help of Ernst & Young and Jose Escay (United States), Tata Energy Research Institute (India), Jan Moen (Norway), Martha Zhanghini (Argentina), David Butcher (New Zealand), Ye Rongsi (China), Julian Sondheimer (U.K.), Bruno Philippi (Chile), and TEK (Turkey).

[3] See data sources at the end of the report for a list.

in prices. All the value comparisons have been made in constant 1991 prices.

The paper is divided into two sections. The first summarizes the study's findings, and the second details the observations in each of the performance areas listed above.

2. Study highlights

Although the study's main conclusions are derived basically from the data comparisons, they are supplemented with what is necessarily impressionistic knowledge of some aspects of the ESI in India. The reader thus is cautioned that the information contains some "gaps" and areas where the data quality is questionable. In addition, differences in accounting practices, power sector structure, and fluctuations in inflation and exchange rates reduce some of the validity of the comparisons. Nonetheless, the major comparisons and conclusions stated below appear sufficiently valid:

- *In India, electricity is treated as a public necessity, and the government is heavily involved in its generation, transmission, and distribution, largely to the detriment of performance.* The data on performance indicate that although the availability of service has grown rapidly under the present organization of the sector, this has not been matched by reliable supply, adequate operational and financial performance, optimal use of existing capacity, and generation of sufficient resources to finance expansion.
- *Problems in the power sector are not atypical of developing countries, but India lags on most financial and operational performance indicators.* India's sector, of course, must serve a large and rapidly expanding population. It also labors under political constraints that prevent it from recovering operating costs from its customers through tariffs. The institutional structure does not provide enough independence for management or sufficient incentives for optimizing coordination in the system, minimizing costs, or setting cost-recovery tariffs. Moreover, the present structure has produced neither an optimal transmission grid nor an optimal coordination of dispatch, and it fails to achieve economies of scale that would reduce generating costs and improve reliability of supply. The structure does foster intense competition for subsidies among the customer groups in the different regions.
- *There is a worldwide tendency to reduce government involvement in the ESI and to promote competition in generation and marketing of electricity, while providing light-handed regulation in T&D.* The United States is fostering open access to the transmission networks of regional utilities; Chile is moving toward separation of transmission from the largest generator in the country; private ownership is increasing in Norway; and several developing countries, including India, are taking hard looks at their institutional frameworks with the intention of raising efficiency of operations and sustaining it over the long run.
- *Expansion of supply, especially in India, is seriously undermined by below-cost tariffs that lead to an overblown demand and to financial shortfalls. The result is a pattern of uneconomic consumption and supply shortage.* Given lower levels of electricity consumption per capita and lower electrification rates, the growth of capacity in developing countries is and should be higher than in developed countries. This also is putting strains on the scarce capital base of these countries.
- *Although the per capita consumption of electricity in India is low, electricity use per gross domestic product (GDP) is high.* This indicates, on the one hand, that further demand growth can be expected with economic development and once reliable supplies become available, and, on the other, that use of the available supply is inefficient.
- *Despite India's high generating plant reserve margin and relatively young system (more than half of capacity entered operation in the last ten years), the growth in transmission has not kept pace with system requirements, and the system is clearly unable to move power efficiently to the major load centers.*
- *Losses are extremely high, reflecting not only technical problems on the grid and weaknesses of commercial systems and procedures but also substantial unauthorized usage.*
- *Available energy and capacity shortages are severe in India despite the high reserve margins.*
- *The potential for new capacity from renewable or environmentally efficient stations appears limited in India.* In building further coal-

fired stations, the environmental considerations could, however, be significant in impact and costly to control.

- *Despite revenue shortfalls and the need for improvements in electricity supply, agricultural and residential power tariffs remain well below long-run marginal cost (LRMC), and a significant portion of the population has unauthorized and unpaid access to the system.*
- *Residential tariffs in developed countries are higher when compared with market exchange rates than in developing countries (India has the lowest tariff of US¢3.27/kWh). When using PPPERs, however, tariffs in developed countries decline relative to the developing countries (India's tariff increases to 10.36¢/kWh).*
- *Tariff distortions are evident in India, Pakistan, and Turkey. Each cross-subsidizes residential consumption and has rates below LRMC.* Among the developing nations, India has the lowest residential tariffs and the widest margin between residential and industrial tariffs. This suggests a massive subsidization of households by industrial customers, highlighting the competitive disadvantage vis-à-vis other surveyed countries, where quality of supply is better and industrial tariffs are lower.
- *India and Argentina are the only countries where average tariffs fail to cover production costs.* Average tariff levels in developed countries are between 5¢ and 10¢ per kWh (the U.K. has the highest average rate with about 9¢/kWh). Tariffs in most developing nations (except Argentina) are above 10¢/kWh, with Thailand, the Philippines, Pakistan, and Indonesia above 20¢/kWh.
- Unit production costs and average revenue vary widely in India. *The common feature is that costs in almost all state electricity boards (SEBs), except one, are higher than sales revenue.*
- *India is—among the countries surveyed—the second-highest-cost producer (about US¢16/kWh) after Indonesia.* The comparison uses PPPERs.
- *Despite India's low wage levels, the share of labor in the total cost of power production is higher than in the United States, U.K., Norway, and the Asian countries in the sample.* This situation has not improved in recent years.
- *Recent investment in the power sector is low compared with other developing countries in Asia, on the basis of GDP, and on the size and output of the power sector.* At present rates of consumption and tariff levels, India will face a considerable investment shortage during the remainder of the decade.
- *The large requirements for investment in electric power are a drain on public finances in a country where education, health, and other social concerns urgently need additional funding.* Improved financial performance in the ESI could enable federal and state governments to devote additional funding to the improvement of the country's human capital and capital infrastructure.
- *The essential lesson seems to be that if electricity is treated more like a normal business and less like one that needs special rules, it will perform better and meet more of the objectives of society, government, and consumer.*

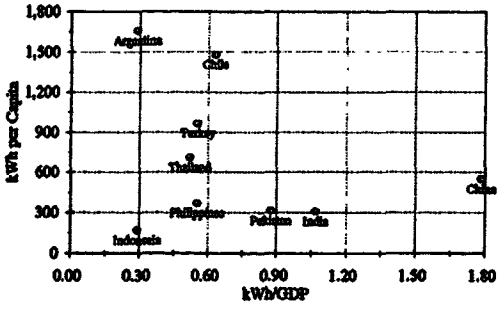
3. Characteristics of the power sector in the sample countries

3.1 Background information

Table 1 (all tables are presented at the end of this paper) presents background information on size, population, and general economic conditions of the countries selected. The sample reflects a wide variety in these indicators. The U.K. and the United States exhibit far higher GDP and intensity of electricity use per capita than do the six developing countries. India is comparatively heavily and densely populated and has a high population growth rate. India also has one of the lowest levels of income per capita yet has a high intensity of electricity use. As Figure 1 shows, the other developing countries in the sample (except China) use electricity better.

Figure 1

Electricity Intensity
1991/90



Of the six developing countries in Asia, Thailand appears to have the strongest economy, with a high per capita GDP, a high growth rate, and a low (relative) inflation rate. India's inflation rate is more typical of the Asian sample.

3.2 *Sector policies*

Energy policy in the surveyed countries emphasizes several different approaches to development and sector reform. Table 2 presents a matrix of policy objectives and shows the main priorities for each country. At one end of the spectrum, the ESIs of China and Indonesia are closely linked to fuel-use objectives. Thus, these countries appear to focus on changing the generation mix to take advantage of indigenous resources and thereby release fuel for exports. At the other end of the spectrum, provincial concerns in India, China, and Thailand outweigh national objectives. The result has been subsidized tariffs, rapid growth in rural distribution networks, and emphasis on setting sector policy at the regional level. In addition, the countries in the sample use different approaches to address the trade-off between consumer welfare and the financial viability of the utilities. In some countries, the welfare of the population is sought at the expense of the commercial viability of the utility, whereas in others (developed countries and countries with reformed ESIs), the focus is on improving utility performance with the assumption that greater customer satisfaction will result.

All of the objectives in Table 2 are being pursued to some degree by each country. Each country wishes to make better use of its fuel resources, but the developed countries and those with reformed ESIs are pursuing this end by using clearly defined economic and commercial criteria, whereas many of the developing countries are still largely driven in their energy policies by strategic and political considerations that may have noneconomic outcomes. Plans for capacity expansion in the developing countries have identified a changing generation mix, particularly a reduction in oil- and diesel-fired plants. Coal and hydro are the most common resources targeted for new development. In China, India, and Turkey, nuclear power production is also contemplated.

In China and India, priorities for development of food production work to the detriment of energy sector financial receipts because both countries provide subsidized energy tariffs for agricultural consumers, which also foster high electricity intensity (see Figure 1). Indonesia, in turn, has focused on extending its power grid, and in the recent past, the heavy investment required has hurt the power sector's financial performance. Both Pakistan and India are addressing chronic electricity shortages and are focusing on increasing generating capability from their utilities and on inviting private sector participation. Turkey is going through a period of institutional uncertainty. Norway, in contrast, is benefiting from competition; real electricity prices are somewhat below the prices before restructuring, but utility savings are higher, and so are the possibilities for profitable exports of electricity and investments abroad. The fully developed power sectors in the United States and the U.K. have begun to focus on environmental issues and on reducing pollution. Chile is fine-tuning its system, responding to charges of discriminatory behavior; ENDESA, the largest generating company and owner of the transmission grid, has voluntarily spun off a separate company to hold the transmission assets.

Influencing customer behavior either through tariffs and demand-side management programs or through electricity marketing measures is emphasized by the countries with reformed power sectors. The United States, U.K., Argentina, Chile, Norway, and New Zealand, Thailand, and the Philippines have developed programs to influence industrial consumption patterns.

There is an about-even split in pricing policies, with half the countries setting prices at the provincial (regional) level and the other half using a national formula. Developing countries at times use both types of pricing policies to encourage development and to cross-subsidize certain consumer groups. In India, for example, the tariff rates vary widely from one SEB to another for the same customer class, with the common feature that tariffs are consistently low among all SEBs for agricultural consumers. In Thailand, national pricing is evident, but the tariff system of the Metropolitan Electricity Authority (MEA) is structured so that urban customers cross-subsidize rural customers.

Most of the Asian countries are moving toward cost-reflective tariffs. High tariff increases in these countries were prevalent in the late 1980s, particularly for low-voltage customers (tariffs are addressed in greater detail later in the report). In Chile, cost-reflective tariffs have been in effect since the 1980s, but in Argentina only since 1992. Turkey, in particular, has recognized that the best manner to address once and for all the inefficiencies of the pricing mechanism is by

reforming the sector along market lines and privatizing the electricity utilities. However, institutional and political obstacles have prevented it from advancing more rapidly along this road.

Improving the financial health of the power sector is also a common emphasis of national energy policy. Indonesia, Pakistan, Turkey, and Argentina have sought to reduce government investment and secure additional capital from debt financing and private equity sources. For similar reasons, the U.K., Argentina, Chile, and Thailand have undertaken privatization programs, and all the other countries in the sample have initiated programs for greater involvement in private generating schemes.

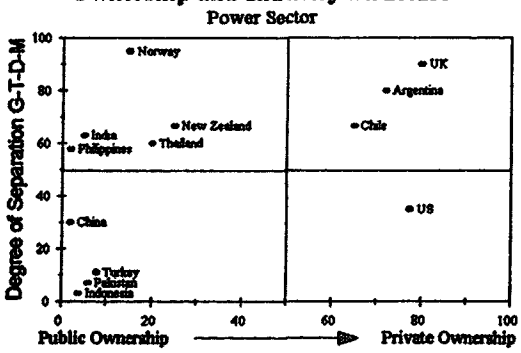
3.3 Institutional structure of the ESIs

The degree of private ownership and the institutional structures of the surveyed countries are diverse (see Figure 2). Four countries have the greatest share of private ownership: the United States, Chile, the U.K., and Argentina. Most of the remaining countries are in transition toward greater private ownership. The organization of the ESIs also varies widely: some are vertically integrated monopolies; others are structured so that generation, transmission, and distribution are provided by separate companies. Five countries have the most unbundled ESIs: Norway, the U.K., Argentina, Chile, and New Zealand. The three countries in the top-right quadrant of the figure are basically private and unbundled. The general trend is for countries to move toward this quadrant: the American and the Chilean systems are thus moving up, whereas the Norwegian and the New Zealand electricity industries are moving rightward.

Figure 2

Ownership and Industry Structure

Power Sector



In China, Indonesia, Pakistan, and Turkey, vertically integrated, publicly held organizations have primary responsibility for power supply. China is served by nine regional utilities providing generation and administering five separate grids. Little self-generation takes place in China, but the regional companies operate more autonomously than do the utilities in Pakistan and Indonesia. Indonesia is characterized by a single publicly held organization, the PLN, which, however, is responsible for only about two-thirds of power generation, with the remainder coming from industrial self-generation and small village cooperatives providing full electric service. Pakistan is served by two publicly held companies, WAPDA and KESCo, with 14 percent of the total power supply resulting from self-generation. Turkey is served by TEK, a publicly owned corporation, which basically controls generation, the interconnected electricity transmission network, and distribution.

The United States has perhaps the oldest continuous private sector ESI. It is a flexible system that has achieved low-cost and reliable supply of power through an evolutionary process that appears to be one of the industry's main sources of strength. The industry is mostly in private hands: three-quarters of the power needs are met by privately held, vertically integrated utilities, with about one-quarter of power requirements serviced by public organizations, cooperatives, and self-generators. Although the United States has approximately 200 investor-owned utilities, it also has more than 1,000 rural cooperatives and small, municipal organizations providing service. These rural and municipal groups have traditionally been distribution entities that typically purchased power from vertically integrated private utilities and various federal marketing areas. More recently, however, they have—individually or in group—undertaken some backward integration into generation.

In contrast to many other countries, where competition has emerged through sweeping all-at-once changes, the United States has progressed toward greater competition in the sector in two stages: at first, competition could take place only in new generating requirements for a given vertically integrated utility; later, competition was extended to bulk supplies outside the service areas with nondiscriminatory access to the regional transmission systems.

The U.K. was reformed and privatized in 1990/91. The industry in E&W is basically

private, with unbundled generation, transmission, and distribution services. The nuclear generating plants (about 8 GW of generating capacity) have remained in the public sector, however, and the utilities of Scotland are still vertically integrated. The U.K. reformed its power sector as part of an overall structural adjustment and privatization program to reduce the weight of the public sector in the economy and ensure the benefits of competition and independent regulation. There are two major private generators, Nation Power (with around 30 GW of capacity) and PowerGen (about 18 GW). Independent generation is growing, however, with the opening of the generating market to independent producers. There are 12 regional distribution companies (RECs), acting as distributors and sellers of electricity. The RECs own the National Grid Company, which manages the transmission system. There is third-party access to T&D. Electricity is bought and sold under long-term contracts and in a spot market.

The power sector utilities in New Zealand have been fully corporatized, with the natural monopoly areas (T&D) effectively separated from the potentially competitive elements (generation and retailing). Generation is dominated by the Electricity Corporation of New Zealand (ECNZ), with 95 percent of generating capacity. There are no entry restrictions to the generation market. ECNZ, corporatized in 1987, sells to the six major industrial and transport consumers, which together account for 25 percent of the market, as well as to the distributors. Trans Power New Zealand Ltd., an ECNZ subsidiary, operates transmission. The government plans in the medium-run to turn it into a stand-alone Crown corporation, and in the long term, into a company owned by a club of generators and retailers. Electricity is mostly distributed by companies formed under the Energy Companies Act of 1992. Shares of these companies were distributed to customers, community trusts, local authorities, and the community at large. Companies operated as departments of local authorities remain under control of the local authorities concerned. The sector is regulated, not through sector specific regulations but rather through the use of anti-competitive practices under the 1986 Commerce Act. Monopoly abuses are kept in check by the threat of regulation. Electricity is no longer consider a public service in need of special treatment but a commodity subject to the commercial code and commercial practices. The emphasis is on market contestability where possible.

Norway carried out a profound reform of the sector, introducing competition at all levels of the industry. Until 1990, the Norwegian policy was to encourage concentration of the electric supply industry into about 20 vertically integrated utilities. However, this policy had not been successful in eradicating a number of inefficiencies in the industry that had developed because of its monopolistic structure and its susceptibility to political influence. Following a change of government, a new market-based approach was adopted for the ESI. The Norwegian reforms shared with the English reforms the aims of reducing the surplus of high-cost capacity and sustaining long-term efficiency. Competition has been stimulated in generation and marketing of electricity, with open access to the T&D grids. Statkraft, a state-owned enterprise (SOE), owns about 30 percent of production capability. Statnett (another SOE) manages the national transmission network, and a multiplicity of small distribution companies have generation facilities. In addition, since 1993, Statnett has assumed responsibility for the operation of the power pool through a subsidiary company, Statnett Marked. The power pool in Norway currently functions as a market only for marginal energy exchanges; otherwise, most energy is provided under firm contracts. Some 54 other owners control medium-voltage networks, of which 40 also operate distribution networks. In total, 200 local distribution utilities are in operation, mostly owned by municipalities or counties. About half of the distribution utilities also own power plants. The private sector is represented by industrial self-production and some generating utilities, which together account for about 15 percent of total production capability in the country.

Chile was the first country to enact sweeping reforms to promote competition and to attempt to sustain it by opening the sector to private investors. There was a progressive privatization of the industry from 1982 onward. The process entailed changing the public's perception of electricity as a service in need of special treatment to just another commercial activity. The experience has helped other countries in Latin America to promote their own reforms (e.g., Argentina, Colombia, Peru, and Bolivia). The Chilean ESI is mostly in private hands and includes 11 generating companies, of which the largest, ENDESA, also controls the transmission

system. About 90 percent of power exchanges take place in the interconnected system, but a few isolated systems also are in operation. Almost all of the distribution services are private. The Comisión Nacional de Energía is in charge of regulating the sector, monitored by the Superintendencia de Electricidad y Combustibles.

Argentina underwent, as part of a far-reaching general reform program in 1991, the restructuring and privatization of public sector companies. The reform in the power sector aimed to overcome the profound power crisis and the inefficiencies in operation and past investments. The reform benefited from an understanding of the experiences of Chile and the U.K. Currently, several generating companies are operating, and generation is open to all investors. Transmission is managed by TRANSENER, and access is open to the lines. CAMMESA, formed by the main sector players (generators, transmission company, distributors, large consumers, and the government), is charged with the dispatching of generation.

The Philippines, Thailand, and India reflect unbundled electric service provided by publicly owned organizations. In all cases, a primary generating company provides service to regional distributors. India has vertically integrated regional utilities in each state, together with some national bulk generation and private licensees undertaking some generation and distribution. Thailand and the Philippines are served by three utilities. Thailand's system is moving toward private ownership.

4. Supply performance

4.1 Installed capacity and generation

Most of the sample countries (except the U.K., the Philippines, New Zealand, and Chile) added significant generating capacity during the 1980s. China ranked first, with an average of 7,782 MW per year, followed by the United States, with 5,643 MW per year, and by India, with an addition averaging 3,528 MW per year (see Table 3). Figure 3 shows average annual capacity additions and capacity growth for the countries in the sample. Assuming an average cost of US$1,000 per kW, the investment in generation in India in the past 10 years amounts to more than $3.5 billion per year, or 1.3 percent of GDP. This does not include additions in transmission, distribution, or customer service investments.

Capacity in the developing countries grew faster than in the developed ones in our sample. The latter are demand driven, whereas growth in the developing countries, given lower electrification rates and low per capita consumption levels, is supply driven. Cost-recovery tariffs are an important instrument for the developing countries to provide efficient and timely supplies. Underpricing in the developing countries has raised demand above economic levels, promoting waste of energy, pressure to invest, and shortfalls in capital funding.

In terms of capacity per capita, the Asian countries in the sample lag far behind the developed countries and behind Argentina, Chile, and Turkey as well. This indicator highlights the known association between electricity supply and economic growth. Figure 4 shows installed capacity per capita for the seven developing countries in the sample.

Figure 3

Average Capacity Growth

1980-91

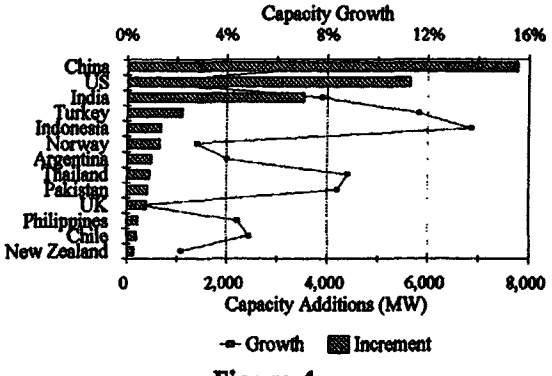
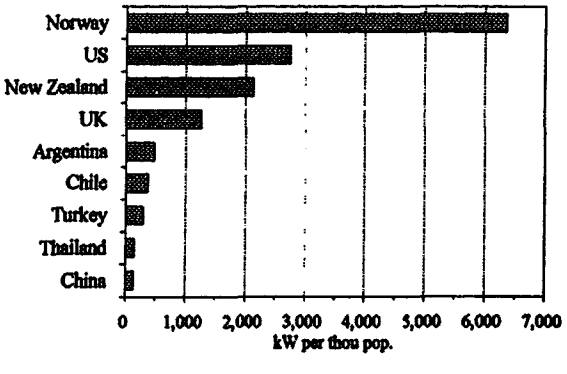


Figure 4

Installed Capacity per Capita

1991



An important achievement of India has been the electrification of most of the country. As Figure 5 shows, India's 80 percent electrification rate is higher than the other Asian countries in the sample and comparable to those of Argentina and Chile. However, the massive electrification was based heavily on subsidies and political considerations, and that explains in part the precarious financial situation of the sector.

In most countries, additions to capacity have been predominantly thermal (see Figure 6). For example, India's growth in hydro generation capacity amounted to only 2 percent during the 1980s, and the country is rapidly approaching the limit of possible hydro additions. India is also the only Asian country in the sample with a commitment to nuclear capacity; nonetheless, India's generation mix remains predominantly coal-fired. All of the Asian countries experienced high inflation during the 1980s as well as electricity shortages, which suggests that higher demand growth, stemming from constant nominal tariffs below LRMC, and capital constraints are holding back expansion of the ESI.

Energy in India (as well as in China) is dominated by coal-fired output; the other Asian countries rely principally on oil, diesel, and gas, and several must import fuel to generate power (see Figure 7 and Table 4). India is less vulnerable and relies almost entirely on indigenous fuel, but much of it is low-grade coal, which raises capacity construction costs and environmental concerns.

Figure 8 shows energy and capacity growth in the sample countries during the 1980s. In the United States and the U.K., as well as in some of the Asian countries, energy growth was higher than capacity. This indicates that plant load factors were increasing, as would be expected. In India, however, capacity growth was not much higher than energy growth (8.7 percent vs. 8.4 percent) despite the obvious reed for additional s··pply. This may be caused by the aging of the system—that is, when the efficiency and reliability of aging generating plants declines more rapidly than can be compensated by the addition of new baseload capacity. Or, it may be caused by the addition of hydro plants with low plant load factors. However, it may also indicate that India's new coal-fired plant is performing below baseload output levels (say below 75 percent plant load factor) or that there is insufficient transmission capacity to move the power to customers.

Figure 5

Electrification Rates
1991

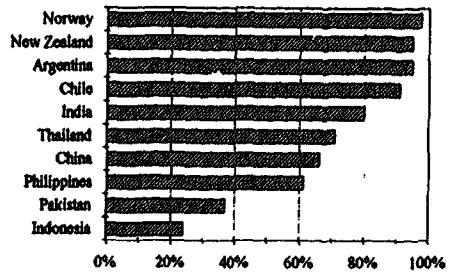


Figure 6

Generating Capacity Structure
1991

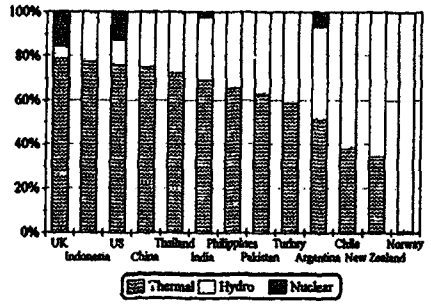


Figure 7

Structure of Generation
% GWh Output

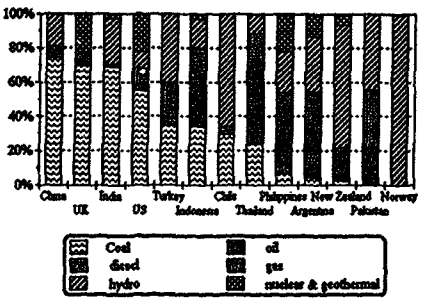


Figure 8

Capacity and Generation Growth
Avg 1980-91 Growth Rates

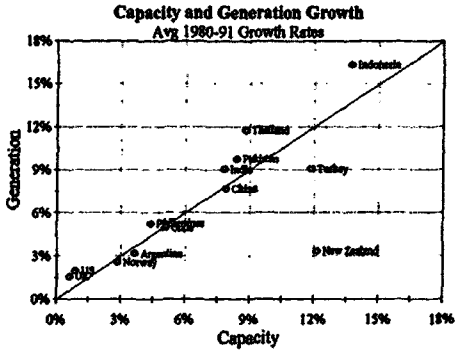


Figure 9

Capacity & Generation

1991

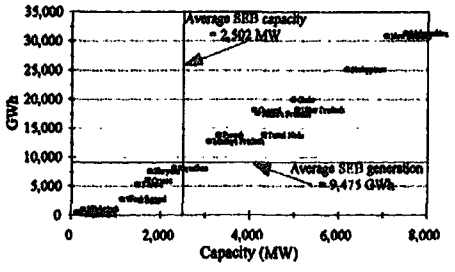


Figure 10

Peak Demand and HV Transmission

1991

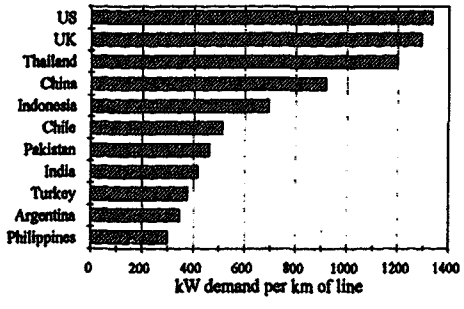


Figure 11

People Served by km of Line

1991

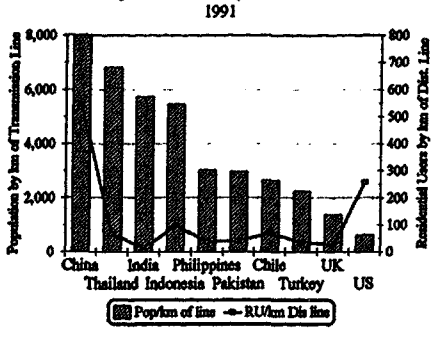


Figure 12

MWh Sales per km of Transmission Line

1991

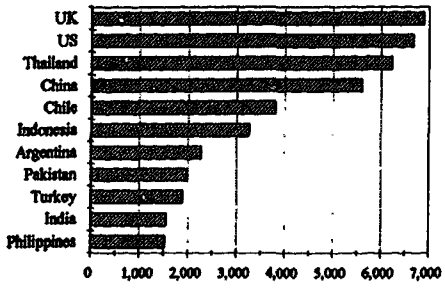


Figure 9 presents the capacity and electricity generated as of 1991 in 17 SEBs. There is a wide variation in the scales of the SEBs, some of which have systems that are as large as those of some countries. The system of Maharashtra SEB, for example, is larger than those of New Zealand, the Philippines, and Chile.

4.2 *Transmission and distribution systems*

Figure 10 shows the ratio between the size of the transmission system and the level of peak demand served for the countries for which information is available. The data indicate the efficiency of the different T&D systems and show how the transmission systems may need to grow to meet demand more effectively.

India's T&D system has a far higher number of people served per kilometer of transmission line at 132 kV or higher than do the systems of Chile, Turkey, the U.K., and the United States (see Figure 11). This measure indicates that India's delivery infrastructure is predominantly low voltage, a factor that contributes to high technical losses and poor quality of service. Most of India's rural distribution network is served by low-voltage wires rather than by an efficient T&D network. On the other hand, on the basis of kilometer of low-voltage line per user, India serves fewer households than any other country: Chile serves 69 residential customers per kilometer of low voltage, Turkey 34, and the U.K. 27, whereas India serves only 15. This suggests serious commercial problems, inadequate registers of consumption, and deficient billing of residential customers. Some residential customers are probably misclassified as rural or commercial, as well. These indicators, especially unregistered consumption, suggest the causes of the high levels of total losses.

The inefficiencies of India's T&D system are also apparent from the ratio of the size of the network to peak demand and customer sales. The high-voltage systems in the other countries move three to four times more electricity (see Figure 12).

Sales in India from 1985 to 1991 grew at 8.4 percent per year and were outpaced by the growth in system losses at 10.2 percent. The transmission system did not keep pace with demand requirements, and this led to power imbalances, shortages, and outages. Peak demand grew at 11.2 percent during the same period, but the generation system increased by only 6.7 percent and the T&D systems by 6.5 percent.

4.3 *Station use and system losses*

Figure 13 summarizes comparative loss ratios for 1980 and 1991. Losses in India were higher than in the three subsets of countries in the sample. Natural losses on the T&D system are expected. The losses reported here include both T&D losses as well as nontechnical losses (primarily illegal consumption, unmetered sales, and billing errors). Technical losses in the United States, China, Norway, and New Zealand are below 10 percent of net generation. As the figure shows, although most other countries reduced their losses over this time frame, India did not.

As Figure 14 shows, the loss ratios of the SEBs are generally in the 15 to 30 percent range, with most clustering above 20 percent. If losses were reduced to 10 percent, India would have an additional 34,700 GWh, which would increase sales revenue by about 14 percent at the current average customer rates.

Station use typically amounts to between 1 percent and 7 percent of net output; coal and nuclear stations tend to be on the high side of this range, whereas hydro is at the low end (see Table 5). As a result of this pattern, station use is lower in the Philippines, Pakistan, Norway, and Chile, which have higher percentages of hydro in the generation mix (see Figure 15). In this perspective, the higher value for India is not unexpected because of the high proportion of coal in generation. Yet it is significantly higher than, for example, the U.K. and China, which also have significant shares of coal in their generation mix. This suggests that India's plants are relatively less efficient in their use of power.

4.4 *Peak demand and reserve margins*

An optimal generating reserve margin (RM) (installed capacity less peak load over peak load), depends on system conditions: the RM in a hydro system (or a small system) is typically greater than in a thermal system (or a large system). However, there are acceptable ranges. For example, the RMs generally range between 15 percent and 35 percent in developed countries. Along with an effective T&D system, utility planners believe, an optimal RM should serve customers with adequate reliability of supply. RMs outside these limits may indicate investment constraints or overinvestment. In the developed countries, electricity shortfalls are caused almost entirely by faults in the transmission system rather than by insufficient generating capacity. Moreover, generation and T&D faults together account for less than 8 hours of total interruption per year in developed countries. The security standard for generation is typically 1 day in 10 years' loss of load probability.[4]

Figure 13

Loss Ratios
1980 and 1991

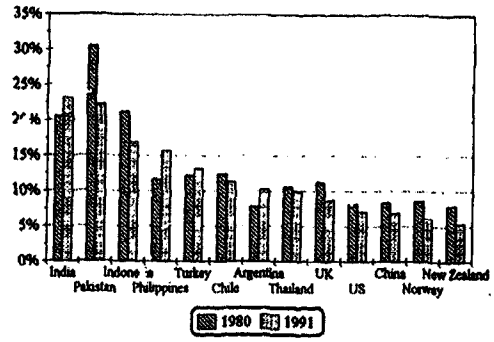


Figure 14

Loss Ratios in India
1991

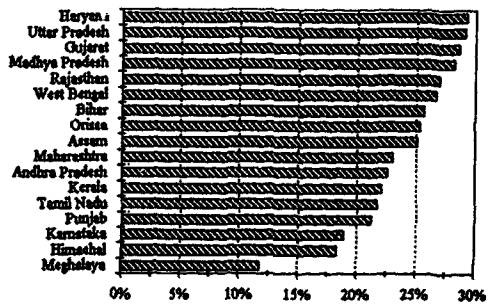
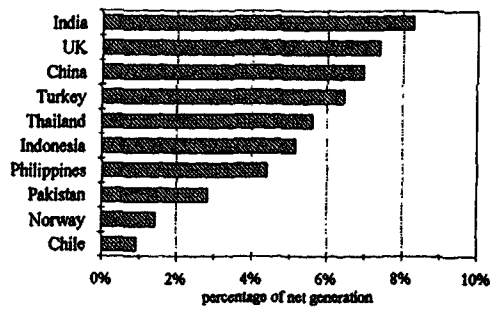


Figure 15

Station Use
1991



[4] This is a probabilistic measure that generating capacity will be unable to meet demand less than 1 day in 10 years.

The surveyed countries exhibit a wide dispersion of RMs (Figure 16). A number of factors could contribute to the excessive reserve margins. First, peak loads may be underreported because of lower generating resources available at the time of peak occurrence. This inflates the RM values. For example, Argentina, Chile, and New Zealand, with their significant shares of hydro (more than 60 percent of capacity) may have hydro capacity available during the rainy season but may incur capacity shortfalls during other times of the year. Plant outages, weather conditions, and (planned or unplanned) load management may also have an impact. The high RM in the U.K. may be partly explained by the positive response of new generators to the opening of the ESI to the private sector. In addition, plant capacity ratings may be overstated, and fuel interruptions and transmission outages may cause energy shortages even in countries with a high reserve margin.

The high RMs of India, the Philippines, Indonesia, China, Turkey, and Argentina, however, suggest a mismatch between supply and demand. In India, the peak demand of 46,500 MW might have been significantly higher if additional generating resources were available. The RM in the United States conforms to the generation and transmission planning targets. In Pakistan and Thailand, reserve margins are significantly below 20 percent, indicating an obvious need for additional capacity.

Electricity consumption in efficient electricity supply systems generally grows faster (or at about the same pace) than peak demand. This improves load factors, enabling (a) operation cost savings (lower-cost plants run more of the time), and (b) investment savings (reduction of expansion requirements). As Figure 17 shows, electricity consumption in the countries above the diagonal lines (the U.K., New Zealand, Chile, Pakistan, and Indonesia) grew faster than peak demand, whereas consumption in the countries inside the diagonal lines (the United States, the Philippines, China, Turkey, and Thailand) grew at about the same pace as peak demand (see Table 6). India was the only country below the lines in the figure. Peak demand grew faster (11.5 percent) than energy consumption (9.2 percent), leading to a deterioration of the load factor.

System load factors are typically in the 60 to 80 percent range on an annual basis and tend to increase with the level of industrial sales. India exhibits the lowest load factor of the surveyed countries for which data are available (see Figure 18). India's low load factor is explained by a variety of reasons. Noneconomic tariffs are perhaps the main reason. Bulk and industrial sales are not subject to time-of-day tariffs with power, peak, and off-peak energy charges. India's daily load patterns largely follow the ability of the system to supply energy rather than changes in load patterns during the course of the day stemming from varying industrial, commercial, and residential usage. Another

Figure 16

Reserve Margins

1991

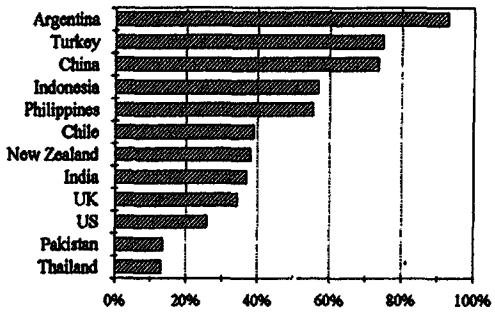


Figure 17

Peak and Energy Demand Growth

1985-91 Annual Growth Rates

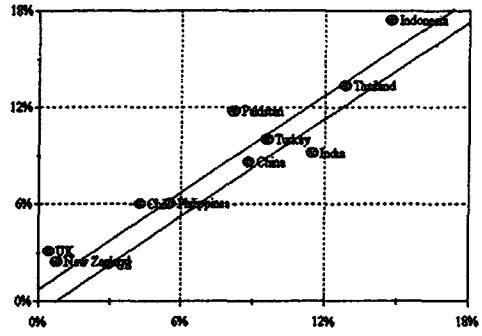
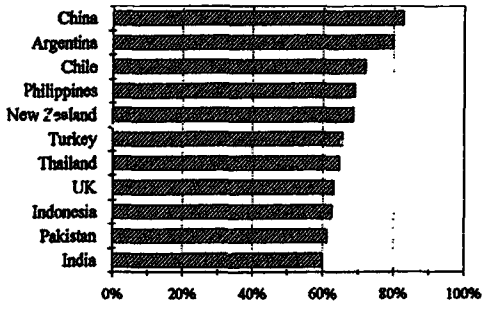


Figure 18

Load Factors

1991



reason for the low load factor is the low per-customer usage in the industrial sector and the significant unreported sales. The relatively low load factor also may be the result of generation and transmission shortages throughout the year.

4.5 *Reliability of supply*

Data on energy shortages in the Asian countries are not reported in a consistent and detailed manner that allows an examination of improvements in the security of supply. Data for India indicate that energy shortages have averaged about 8 percent of anticipated requirements, whereas demand shortages have been in the 12 to 17 percent range. Electricity interruptions are common throughout India, as in most developing Asian countries. Load shedding is common in Pakistan, where unmet load reaches up to 25 percent of peak load served. MEA in Thailand reports a good annual average outage duration of 124 minutes. In Argentina, a severe power crisis in 1988-89 was triggered by a drought in 1988 and was compounded by the unavailability of thermal equipment to compensate for the low flow in the hydro generating system. Serious power cuts and conservation measures (rationing and load shedding) were necessary throughout the country on a daily basis during the peak season. The Argentine treasury estimated operating losses for the ESI of US$50 million per month, and a much larger economic loss for the country in terms of productivity lost. This power crisis prompted support for the restructuring of the sector. At present, the new generating companies have made rehabilitation investments that have resulted in improvements in operational efficiency and reliability. The number, length, and frequency of the outages that afflicted the 1980s and early 1990s have already been reduced, and outages should be eliminated completely in the short term. In Chile, the quality of the service is considered better after privatization, with full modernization of the public systems and quicker responses to requests for service. Quality of supply in the United States, the U.K., Norway, and New Zealand is considered acceptable. Outages in these systems are caused entirely by faults in the T&D system and are within normal parameters.

4.6 *Environmental performance*

Data on NO_x, SO_2, ash, and other indicators of environmental quality in the power sector are not generally available for the Asian countries. Current production in China and India is being met from coal-fired plant. In Indonesia, generation expansion will likely come from coal sources. In India, coal quality is low, and the older plants do not have scrubbing equipment. The United States, U.K., Norway, and New Zealand have programs to reduce the environmental impacts of the power sector. In Turkey, although emissions of SO_2 per capita are relatively low, in line with energy consumption per capita, emissions per unit of energy consumed are high, coming primarily from lignite. Plans are being made to equip thermal power plants with FGD units, but Turkey lacks any air quality regulation that would make investors consider air emission levels as well as monitoring of NO_x and particulate emissions.

5. Demand indicators

5.1 *Consumption by customer class*

Each country shows a unique consumption mix that varies according to the level of development (see Figure 19 and Table 7). In the developed countries, the consumption mix has remained relatively static at about one-third residential (household), one-third industrial (high-voltage users), and the remainder comprising commerce, agriculture, transport, government, street lighting, and other services. In the developing countries, the most notable change appears to be an increase in residential and commercial usage as additional supplies become available and the system grows. In India, the industrial proportion of consumption has dropped, and the

Figure 19

Sales Mix
1991

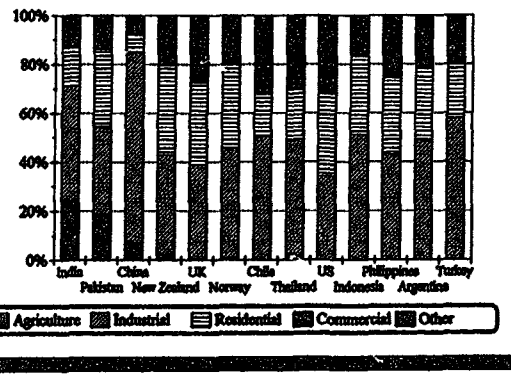


Figure 20

Average Growth in Demand
1980-91

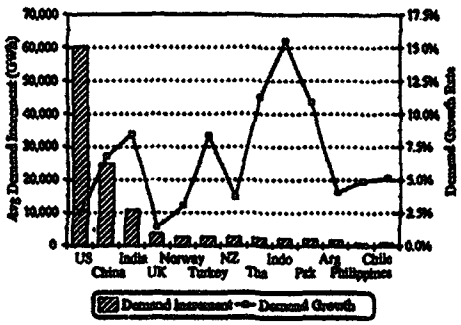
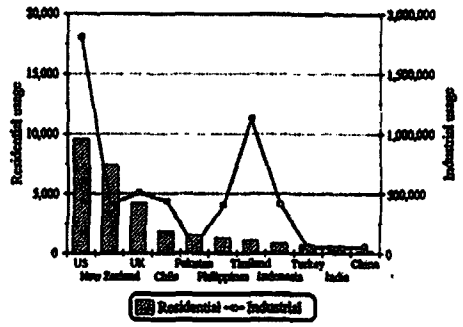


Figure 21

Average Consumption per User
kWh per year



agriculture and residential proportions have grown. The agricultural share in India is the highest of the countries in the sample, probably because of the heavy consumption by agriculture. This factor also may account for the lower average usage than in the other countries. The largest share of consumption in China, however, has been industrial (>70 percent), with increases in residential usage occurring only in recent years.

Figure 20 shows the average demand increments and the growth in demand for the 1980-91 period. It is apparent that the United States has the largest demand increment because of the sheer size of its ESI, the largest in the world, and Chile, the smallest in the sample, has the smallest increment. The increments prefigure the significant effort China and India will have to make to provide for these requirements. The rates of demand growth show a different picture. The developed countries—New Zealand, Norway, the United States, and the U.K.—grew at conservative, low rates, whereas the developing Asian countries—Indonesia, Thailand, Pakistan, and India—grew at high rates.

In India, residential consumption has tripled over the 1980-91 period. The growth in industrial consumption generally lags behind the growth in residential use. Whereas the consumption growth rates in India are high, the statistics on average usage indicate a substantial lag behind the developed countries. Residential usage in the U.K. is about seven times higher than in India (in Europe, average usage is about 2,500 kWh/customer-year). On a per customer or per capita basis, India is far behind the other countries in the sample, except China, which only recently began residential service.

5.2 *Electricity customers*

Figure 21 shows average use per customer for the residential and industrial classes and indicates that usage is substantially lower in the developing countries, with India second to last. The extremely low intensity of electric consumption in the residential sectors in China, India, Turkey, and Indonesia indicates the level of development in providing access to electric service.

The customer mix in India, consisting of 71 percent residential, is lower than the other countries in the sample (see Table 8). This may be further evidence of the lack of access to the system. It may also indicate the commercial problems of improper customer classification, inadequate billing of consumption, and high levels of unauthorized consumption.

5.3 *Customer tariffs*

This section highlights the results of a comparison of customer tariffs for the selected countries. We examine tariffs from an economic and financial perspective; that is, the ability of customer tariffs to promote economic efficiency and cover production costs. The first measure is examined by seeing whether tariffs meet the LRMC of production, the second by checking whether tariffs are sufficient to result in financially viable utilities. Table 9 presents the main characteristics of the tariff schedules in the surveyed countries.

A previous World Bank study[5] concluded that tariffs in developing countries fell short of both of these objectives, observing that the ratio of bulk (wholesale) rates to low-voltage tariffs

[5] Energy Development Division, Industry and Energy Department, "Review of Electricity Tariffs in Developing Countries During the 1980s," Energy Series Paper 32, World Bank, 1990.

(primarily household and small commercial) was higher than expected, indicating that cross-subsidies were present and that low-voltage tariffs were failing to capture the additional costs of greater line losses, investments in distribution, and expenditures for customer service.

International comparison of tariffs with market/official exchange rates (OER) are misleading, because the tariffs fail to provide an accurate picture of the value relative to the purchasing power of the countries' populations. Most developing countries with undervalued currency appear—using OER—to have low average tariffs and unit costs of production, whereas developed countries with OER in line with purchasing power appear to have relatively higher numbers. In this paper, we use the World Bank's PPPERs.

The first significant result of using PPPERs is that whereas residential tariffs in the developed countries are higher with OER than developing countries (India has the lowest tariff of US¢3.27/kWh), when using PPPERs, tariffs in developed countries decline substantially in relative terms, and those of developing countries increase (India's tariff rises to 10.36¢/kWh). The second significant result is that India goes from being a low-cost producer (with OER) to the second-highest-cost producer (about US¢16/kWh) after Indonesia.

The tariff comparison highlights that India and Argentina are the only countries where tariff rates fail to cover production costs[6] (see Figures 22 and 23). Average tariff levels in developed countries are between 5¢ and 10¢ per kWh (the U.K. has the highest average rate with about 9¢/kWh). Tariffs in most developing nations (except Argentina) are above 10¢/kWh, with Thailand, the Philippines, Pakistan, and Indonesia above 20¢/kWh.

It was noted that the Asian developing countries in the sample, as well as Argentina, are addressing the discrepancy between customer tariffs and LRMC as part of their overall energy strategy. Most of these countries employ flat usage (per kilowatt hour) charges to low-voltage customers and both demand and energy components to large industrial customers. Most include a fuel price adjustment, but some do not include this in the residential rates. Most also have lifeline rates for low-usage customers; for example, Pakistan has an increasing block usage rate. Thailand, Argentina, Chile, New Zealand, Norway, the U.K., and the United States, use time-of-day tariffs for industrial customers.

The cost and revenue situation in India is not homogeneous. Although unit costs in most of the SEBs are higher than average sales revenue, Himachal SEB is in a better situation than most, receiving about 19.29¢/kWh sold, which costs about 19.26¢/kWh to produce.

Tariff distortions are particularly evident in India, Pakistan, and Turkey, each of which has cross-subsidies and rates generally below LRMC (see Figure 24). Under economic pricing, industrial tariffs are generally lower than residential tariffs, reflecting the lower costs of supplying industrial consumers. A situation of residential tariffs below industrial tariffs generally indicates cross-subsidization. India has, on the one hand, the lowest residential tariffs, and, on the other, the widest margin between residential and industrial tariffs. This combination suggests a massive sibsidization

Figure 22

Unit Cost and Revenue

US¢ of 1991 per kWh

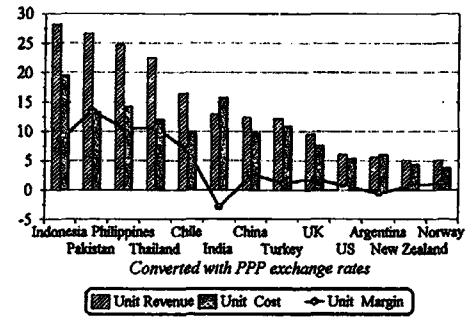
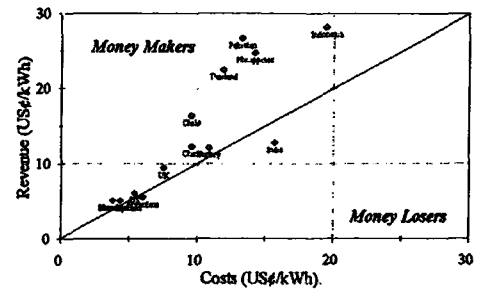


Figure 23

1991 Unit Costs & Average Revenue

(Using PPP Exchange Rate)



[6] It is important to note that Argentina data corresponds to 1991. In 1992, the average electricity rate had increased to 5.7¢/kWh (from 4.2¢).

of households by industrial customers. Industrial tariffs in India, Turkey, and the Philippines highlight their competitive disadvantage vis-à-vis the other surveyed countries, where tariffs are significantly lower.

Tariffs increased at higher rates in Turkey, China, the U.K., and Norway. However, in India, Pakistan, and the Philippines, tariffs declined further. As a result, the financial situation of most power sector utilities in India has worsened. Of the Asian countries, Thailand has been more successful at setting cost-recovery tariffs.

Figure 24

Residential & Industrial Tariffs
1991

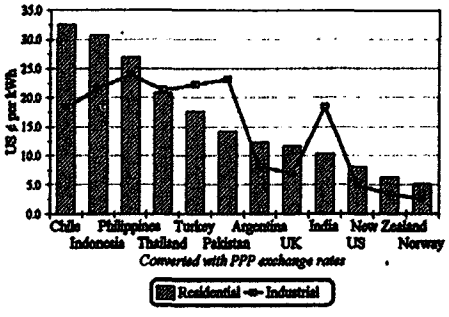


Figure 25

Sales and Customers per Employee
1991

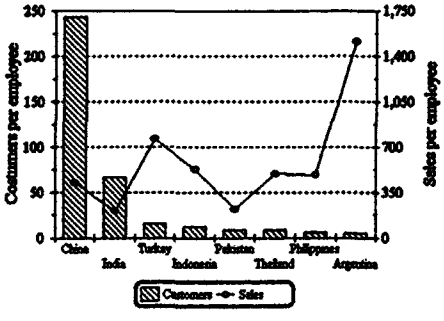
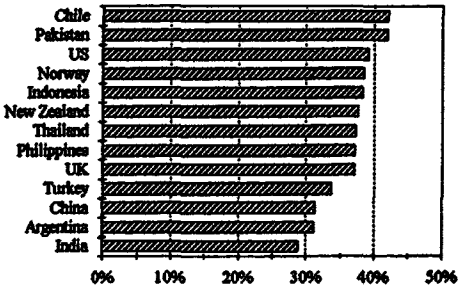


Figure 26

Thermal Plant Efficiency
1989-1991 Average



6. Productivity indicators

6.1 *Labor productivity*

Figure 25 and Table 10 present labor productivity, showing the number of customers served and sales per employee for the Asian countries, Turkey, and Argentina. These are common standards for levels of efficiency and performance. As might be expected, the countries with the largest populations and systems have the larger number of customers per worker. Even though the values are within a close range, India appears to employ twice as many people as needed. Sales per employee (MWh/L) is a better measure of relative productivity. Sales in the developed countries range from 1,965 MWh/L in the U.K. to 5,519 MWh/L in Norway (1991 figures). The MWh/L ratio in the developed countries is biased because of the higher intensities of consumption. Reform in E&W enabled the two private generating companies to reduce labor drastically. National Power cut labor from 17,000 to 6,000, and PowerGen went from 10,000 to 4,700. The developing countries with reformed ESIs also have higher MWh/L ratios. Chile sells 4,972 MWh per employee, and Argentina 1,516 MWh. The situation is different for India, however. As can be appreciated in Figure 25, India, with 204 MWh/L, has the lowest MWh/L ratio, about 20 times less than the U.K. It is clear that India and Pakistan employ a huge work force in their power sectors and that this may be a gauge of their inefficiency.

Note, however, that these measures do not indicate skill levels, relative numbers of managerial and administrative employees, amount of services contracted out, or the distribution of labor between generation, transmission, distribution, and customer service. The values also do not indicate whether or not India's labor *costs* in the power sector are out of line with the others. That question is explored in the section on financial performance.

6.2 *Power plant performance*

India's thermal efficiencies are the lowest among the sampled countries (see Figure 26 and Table 11). International experience indicates that

thermal efficiencies typically vary between 30 and 50 percent. India's thermal efficiencies since 1985 have never been above 27 percent, however.

Table 12 presents a comparison of recent experience in Indian and United States coal-fired thermal plants. It shows that in general India's fuel quality is below United States averages, heat rates and station use are higher, and availability and net output are below United States performance. In particular, station output is below what would be expected under conditions where energy shortages occur (plant load factor < 70 percent). Plant load factor in the United States is constrained by economic dispatch; this is an indication of the difference between United States availability and net output. In India, the difference stems both from partial outages at the plants and from transmission constraints.

7. Financial challenges

7.1 Cost and financial performance

India's labor costs are higher than the other Asian developing countries in the sample but lower than Argentina's and Turkey's (see Figure 27 and Table 13). The data on Argentina portray the situation prevailing in 1991, during the power crisis that prompted the sector's restructuring and eventual privatization. However, in Turkey and India, the high labor costs appear to be caused by overemployment. The share of labor in total production costs in the developed countries varies within a narrow range of 11 to 20 percent. Given the lower labor costs of developing countries, the share of labor costs should be anywhere between 4 and 13 percent; for example, Pakistan has a 3.9 percent share of labor costs, China 4.4 percent, and Indonesia 12.8 percent. This last value might be considered on the high side, but it is overshadowed by India's 20.1 percent share and Turkey's 40.1 percent.

India's fuel costs may also be considered too high, especially given the high use of indigenous coal and hydro in its generation mix. In the U.K., the fuel share amounts to 47.1 percent, while in India it is 52.3 percent. The 5.1 percent share of operation and maintenance (O&M) in India is lower than most of the countries in the sample, with only the Philippines (4.7 percent) and Turkey (0.6 percent) spending less (although perhaps some of these costs are included in the labor category). O&M costs in hydro systems are lower than in thermal ones. Norway and Argentina thus spend 6 to 11 percent of their total expenditures on O&M, whereas the U.K. and the United States spend 27 to 45 percent. The low O&M may help to explain the low availability factor and the need to compensate with a high margin of reserve. The share of financial and administrative costs is lower in India than in the other developing Asian countries, despite the large amount of new generating plant. There are substantial depreciation costs in China, Indonesia, Pakistan, the Philippines, and Thailand.

Figure 28 presents the operating margins in the sampled countries. Several issues are raised by these values. First, India's sales revenue is below that of the other countries (except that of Argentina) and fails to recover production costs. Second, Pakistan, Thailand, and the Philippines, despite the tariff subsidies to selected customer

Figure 27

Cost Structure
1991

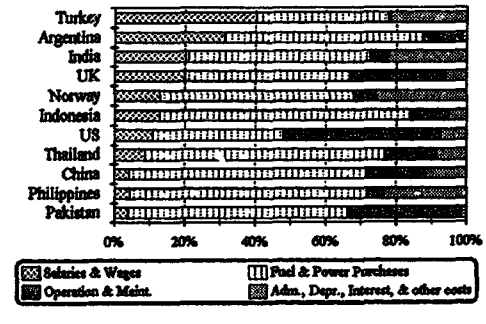
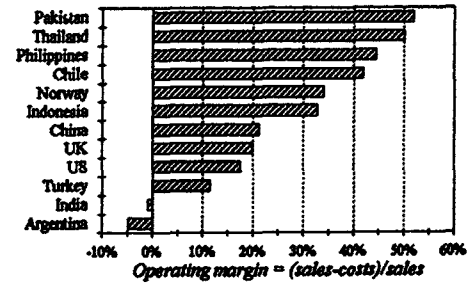


Figure 28

Operating Margin
1991



classes, have high operating margins that help them to face the investment challenges. In India, residential and agricultural power tariffs are below the marginal cost of production, and the tariff levels of industrial consumers are not enough to compensate for the shortfall.

Given the problems with the information, a word of caution is in order. The countries surveyed do not report operational and financial costs consistently. Some countries do not include depreciation as part of the cost of operations, for example, whereas others do. The U.K. reports cost data in constant currency, but the others report on a current basis. Comparisons are also difficult in that countries do not fully explain how they categorize costs. For example, executive salary costs cannot be distinguished as either labor or administrative. In addition, labor costs might be included in either the fuel category or the repairs and maintenance category.

7.2 *Investment challenge*

Significant investment has occurred in Argentina, Pakistan, and India. The available data do not appear to indicate that India, China, and the Philippines have kept pace with demand and system growth requirements (see investment per MWh sales in Figure 29 and Table 16). Countries with relative overcapacity—Norway, Chile, the U.K., and the United States—have needed only relatively minor investments to keep up with demand growth.

Although the quality of the financial information of the SEBs is variable and wanting in some respects, the information generally conveys a difficult financial situation for most SEBs. Rates of return are mostly low or negative, ranging from -15 percent to +23 percent (see Figure 30). The average level of cash generation of the SEBs was only 1.3 percent of their investment requirements. This compares unfavorably with World Bank targets of between 20 and 60 percent. Collection periods in most SEBs are about three months, ranging from 55 days for Tamil Nadu to 371 days for Meghalaya.

Based on recent investment, required system improvements, current demand growth trends, and existing tariff levels, India will face a significant power investment gap during the rest of the decade (see Figure 31). Assuming an expected demand growth of 7.8 percent and an investment cost of US$1,940 per kW of incremental supply capacity, India will have investment requirements of about $117 billion for the 1993-2000 period. Under current tariff levels, India can only provide $6 billion, multilateral institutions $5 billion, and other bilateral and commercial institutions another $7 billion, leaving a gap of $99 billion.

Figure 29

Investment per GDP & Sales

1991

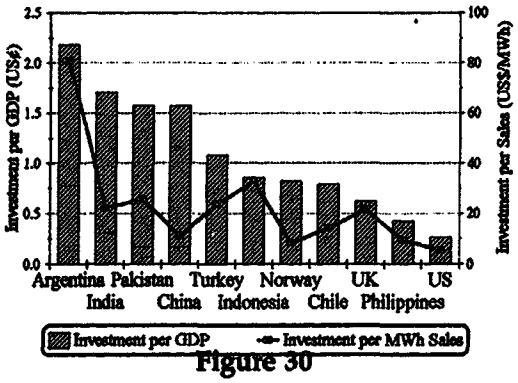


Figure 30

Financial Performance of SEBs

1991

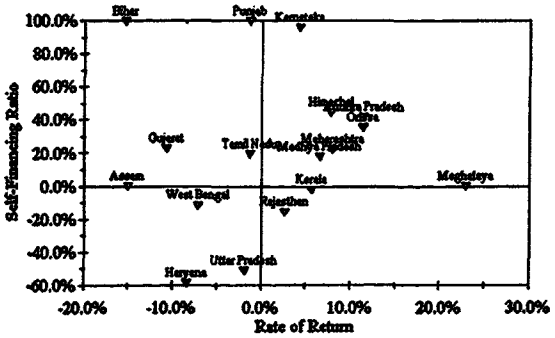
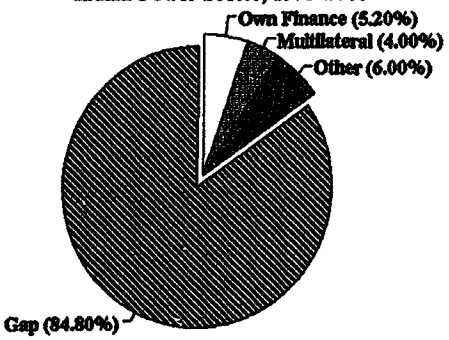


Figure 31

Expected Investment Sources

Indian Power Sector, 1993-2000



Total Investment Requirements = US$ 117 billion

Data sources

Author/publisher	*Title*	*Year*
Asian Development Bank	• Electric Utilities Data Book for the Asian and Pacific Region • Energy Indicators of Developing Member Countries of ADB	1991 & 1993 1989 & 1992
Co-Operative Program on Energy Development	Key Issues Facing the Electricity System of Argentina	1990
Ernst & Young	Electricity and Gas Distribution in the (European Community) Member States	1991
International Energy Agency	• Energy Policies of IEA Countries • Electricity in IEA Countries • Energy Balances of OECD Countries 1980-89 and 1989-90	1991 1985 1990 & 1992
Water and Power Development Authority	Power System Statistics: Seventeenth Issue	1992
The Electricity Council (U.K.)	Handbook of Electricity Supply Statistics	1986-89
United Nations	• Electric Power in Asia and the Pacific 1987-88 • Energy Balances & Electricity 1990 • Energy Statistics Yearbook 1988 & 1991	1991 1993 1990 & 1993
U.S. Central Intelligence Agency	Handbook of International Economic Statistics	1992
U.S. Energy Information Administration	• Electric Power Annual • Financial Statistics of Major Investor-Owned Electric Utilities • Electric Plant Cost and Power Production Expenses	1986-90 1991 1986-90
Utility Data Base	U.S. Steam-Electric Plants: Five Year Production Costs 1986-90	1992
World Bank	Power Sector Statistics for Developing Countries, 1987-91 (Draft)	1994

Table 1
Background country information

	China	India	U.S.	Indonesia	Pakistan	Philippines	Turkey	U.K.	Thailand	Argentina	Chile	Norway	New Zealand
Demographic data													
Land Area (km^2)	9,556,102	3,288,000	9,529,202	1,919,443	796,100	300,000	779,000	234,497	513,115	2,776,000	756,950	306,808	270,534
Population (million 1991)	1,151.5	866.4	252.5	193.6	117.5	65.8	58.6	57.5	56.8	32.7	13.4	4.3	3.3
Population growth rate (1980-91)	1.4	2.1	0.9	2.2	3.1	2.4	2.4	0.3	1.8	1.3	1.7	0.4	0.8
Population density (POP/km^2)	120	263	26	101	148	219	75	245	111	12	18	14	12
% Rural	73.6	72.5	0	72	72.8	58.2	0	0	78	14.7	0	28	15
General economic data													
GDP (1991 prices) bn $	379.5	268	5,677.5	115.9	43	45.3	108.6	1,014.6	81.4	172.5	31.3	105.9	42.4
GDP per capita	329.6	309.4	1,853.8	22,485	598.7	365.6	5,280.9	17,640.8	688.8	1,432.7	2,338.4	12,815	24,785.1
GDP growth rate 1980-91	8.76	5.76	2.6	5.51	6.27	1.61	5.1	2.6	7.75	-1.3	3.79	1.6	3.6
% Inflation (1985-91)	11.13	9.3	3.76	8.62	7.63	9.84	51.79	5.85	5.06	965.4	19.8	4.3	8.54
1991 Average exchange rate (currency/$U.S.)	5.32	22.74	1	1,950.3	23.8	27.48	4,171.8	0.57	25.52	0.92	349.37	6.48	1.73
Electricity access and intensity													
% Population access to electricity (1991)	66	80	100	24	37	61	NA	100	71	95	91	97.7	95
Electricity intensity per capita (1991)	550.0	305.7	11,188.1	167.1	311.6	365.7	966	5,226.2	708.1	1,655.3	1,477.1	25,608.4	9,317.3
Electricity intensity per GNP unit (1991)	1.79	1.07	0.5	0.29	0.88	0.55	0.55	0.32	0.52	0.29	0.63	1.05	0.73

Table 2
Policy Objectives

	U.S.	U.K.	Norway	New Zealand	Argentina	Chile	Turkey	China	India	Indonesia	Pakistan	Philippines	Thailand
Link to other energy resources													
• Exploit indigenous fuel	X	X	X		X	X	X	X	X	X	X	X	X
• Promote coal/lignite					X				X	X	X	X	X
• Promote hydro			X		X			X	X				X
• Promote nuclear								X	X				
Population welfare													
• Link to food production								X	X				
• Reduce energy shortages							X		X		X		
• Improve rural distribution network										X			
• Reduce pollution	X	X	X	X		X		X					
Influence customer behavior													
• Promote efficient electricity use	X	X	X	X	X	X							X
• Promote conservation & demand management	X	X	X	X								X	X
Pricing policy													
• Rationalize prices (attain commercial prices)	X	X	X	X	X	X		X		X	X	X	X
• National prices							X	X		X	X		X
• Promote regional development & income distribution	X						X	X	X				
Financial policy													
• Reduce government investment (additional debt financing)					X		X			X	X		
• Attain satisfactory returns on investment	X	X	X	X	X	X			X				
Privatization strategy													
• Integrate BOO schemes, industrial self-generation	X	X	X	X	X	X	X		X		X	X	X
• Sell utility into the private sector		X	X	X	X		X						X

Table 3
Size of electricity systems - MW of capacity

	U.S.	*China*	*U.K.*	*India*	*Norway*	*Turkey*	*Argentina*	*Indonesia*[1]	*Thailand*[1]	*Pakistan*[1]	*New Zealand*	*Philippines*[1]	*Chile*
Installed capacity 1991	693,016	151,473	73,157	69,025	27,139	17,207	15,563	9,256	8,027	7,728	7,067	6,174	4,969
Capacity growth rate 1980-91	0.9%	7.9%	0.6%	7.8%	2.8%	11.9%	3.7%	13.7%	8.8%	8.4%	12.2%	4.4%	5.1%
Average capacity additions (MW/year 1980-91)	5,643	7,782	395	3,528	648	1,099	498	670	458	428	642	217	184
Installed hydro capacity 1991	92,031	37,884	4,190	19,914	26,889	7,114	6,591	2,095	2,240	2,897	4,619	2,148	3,088
Installed nuclear capacity 1991	99,589	NA	11,353	1,735	0	0	1,018	0	0	0	0	0	0
Installed other thermal capacity 1991	600,985	113,590	57,474	48,096	250	10,093	7,954	7,161	5,787	4,831	2,449	4,026	1,881
Hydro capacity additions 1980-91	14,534	15,728	1,850	6,963	7,107	4,633	2,990	1,716	970	1,330	4,646	1,208	957
Nuclear capacity additions 1980-91	43,134	0	5,316	875	0	0	648	0	0	0	0	0	0
Thermal capacity additions 1980-91	44,991	56,332	(7,700)	27,346	14	6,563	1,654	4,985	3,609	2,952	2,536	965	411
Inst. capacity per capita (kW/000 pop)	2,744.6	131.5	1,272.0	79.7	6,350.4	293.7	476.5	47.8	141.3	65.8	2,135.7	93.9	371.1

[1]1990 data.

Table 4
Size of electricity systems - GWh of generation

	U.S.	*China*	*U.K.*	*India*	*Norway*	*Turkey*	*Argentina*	*Thailand*	*Pakistan*	*Indonesia*	*New Zealand*	*Philippines*	*Chile*
Gross generation GWh 1991	2,825,023	677,494	322,805	286,711	111,009	60,246	50,124	42,491	37,645	34,011	30,858	25,105	19,961
Generation growth rate (1980-91)	1.9%	7.7%	1.6%	9.0%	2.6%	9.0%	3.1%	11.7%	9.7%	16.3%	3.3%	5.2%	4.9%
• Growth in hydro generation		7.2%	2.8%	4.1%	2.5%	6.5%	0.8%	11.4%	6.9%	15.5%	1.9%	5.7%	5.4%
• Growth in thermal generation	2.2%	7.8%	-0.8%	11.6%	10.9%	11.0%	4.6%				9.5%		4.1%
Capacity growth rate 1980-91	0.9%	7.9%	0.6%	7.8%	2.8%	11.9%	3.7%	8.8%	8.4%	13.7%	12.2%	4.4%	5.1%
1991 GWh generation by fuel													
• Coal	1,551,167	504,030	208,124	180,936	0	20,181	2,450	10,230	65	11,603	736	1,741	5,908
• Oil	108,176	44,666	22,662	0	0	3,921	5,960	9,067	8,137	9,825	6,193	9,767	0
• Diesel	3,287	0	50	77	0	21	0	267	5	4,814	64	2,071	522
• Gas	264,172	3,953	0	5,439	0	10,192	21,170	18,057	12,513	969	0	0	403
• Nuclear & geothermal	622,702	0	61,308	6,244	429	80	7,140	0	0	1,125	2,018	5,470	0
SUBTOTAL	2,549,504	552,649	292,144	192,696	429	34,395	36,720	37,621	20,720	28,336	9,011	19,049	6,833
• Hydro	275,519	124,845	6,375	71,535	110,580	23,148	17,350	4,864	16,925	5,675	22,895	6,074	13,128
TOTAL GENERATION	2,825,023	677,494	298,519	264,231	111,009	57,543	54,070	42,485	37,645	34,011	31,906	25,123	19,961
1991 % generation by fuel type													
• Coal	54.91%	74.40%	69.72%	68.48%	0.00%	35.07%	4.53%	24.08%	0.17%	34.12%	2.31%	6.93%	29.60%
• Oil	3.83%	6.59%	7.59%	0.00%	0.00%	6.81%	11.02%	21.34%	21.62%	28.89%	19.41%	38.88%	0.00%
• Diesel	0.12%	0.00%	0.02%	0.03%	0.00%	0.04%	0.00%	0.63%	0.01%	14.15%	0.20%	8.24%	2.62%
• Gas	9.35%	0.58%	0.00%	2.06%	0.00%	17.71%	39.15%	42.50%	33.24%	2.85%	0.00%	0.00%	2.02%
• Nuclear & geothermal	22.04%	0.00%	20.54%	2.36%	0.39%	0.14%	13.21%	0.00%	0.00%	3.31%	6.32%	21.77%	0.00%
• Hydro	9.75%	18.43%	2.14%	27.07%	99.61%	40.23%	32.09%	11.45%	44.96%	16.69%	71.76%	24.18%	65.77%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 5
Generation balance (1980 & 1990) - GWh

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Generation in 1990													
Gross generation	621,320	264,231	34,011	37,645	25,105	42,491	2,808,151	319,695	47,007	57,543	18,372	30,157	121,848
Less station use	40,033	20,177	1,674	1,035	1,056	2,261	0	22,236	0	3,311	324	27	1,358
Net generation (Busbar)	581,287	244,054	32,337	36,610	24,049	40,230	2,808,151	297,459	47,007	54,232	18,048	30,130	120,490
Plus net imports	0	1,506	856	439	4	689	0	11,943	0	175	0	0	(15,907)
Less T&D losses and theft	40,113	57,320	5,453	8,114	3,763	4,023	199,498	24,984	5,477	6,680	1,944	1,588	6,874
Net sales to customers	541,174	188,240	27,740	28,935	20,290	36,896	2,608,653	284,418	41,530	47,727	16,104	28,542	97,709
Station use as a % of net generation	6.9%	8.3%	5.2%	2.8%	4.4%	5.6%	0.0%	7.5%	0.0%	6.1%	1.8%	0.1%	1.1%
T&D losses as a % of net generation	6.9%	23.5%	16.9%	22.2%	15.6%	10.0%	7.1%	8.4%	11.7%	12.3%	10.8%	5.3%	5.7%
Ration: sales to generation plus imports	87.1%	70.8%	79.6%	76.0%	80.8%	85.4%	92.9%	85.8%	88.3%	82.7%	87.7%	94.6%	92.2%
Generation in 1980													
Gross generation	300,628	110,943	7,502	14,872	15,086	14,028	2,286,106	272,225	35,671	23,275	11,751	NA	84,099
Less station use	18,042	7,230	343	421	784	638	station	17,345	0	1,394	145	NA	1,401
Net generation (Busbar)	282,586	103,613	7,159	14,451	14,302	13,390	2,286,106	254,880	35,671	21,881	11,606	NA	82,698
Plus net imports	0	1,416	919	291	0	746	0	1,953	23,532	1,341	0	NA	(462)
Less T&D losses and theft	23,373	21,325	1,517	4,392	1,665	1,406	186,344	21,001	2,786	2,824	1,442	NA	7,129
Net sales to customers	259,213	83,704	6,561	10,350	12,637	12,730	2,099,762	235,832	56,417	20,398	10,164	NA	75,107
Station use as a % of net generation	6.38%	6.98%	4.79%	2.91%	5.48%	4.76%	0.00%	6.81%	0.00%	6.37%	1.25%	NA	1.69%
T&D losses as a % of net generation	8.27%	20.58%	21.19%	30.39%	11.64%	10.50%	8.15%	8.24%	7.81%	12.91%	12.42%	NA	8.62%
Ration: sales to gross generation plus imports	86.2%	74.6%	77.9%	68.3%	83.8%	86.2%	91.8%	86.0%	95.3%	82.9%	86.5%	NA	89.8%

able 6
eak demands (1980-1991) - MW

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Peak demand (MW)													
1980	38,458	19,089	1,577	2,614	2,414	2,417	NA	51,301	NA	3,892	1,544	NA	NA
1981	39,564	20,121	1,876	2,897	2,620	2,589	NA	49,444	NA	4,025	1,588	NA	NA
1982	41,919	21,527	2,285	3,436	2,913	2,838	NA	50,286	NA	4,475	1,643	4,084	NA
1983	44,958	23,077	2,413	3,781	3,117	3,204	NA	48,602	NA	4,608	1,716	4,270	NA
1984	48,227	24,020	2,715	4,027	3,049	3,547	NA	48,890	NA	5,380	1,825	4,533	NA
1985	52,538	26,248	2,965	4,588	3,037	3,878	NA	53,083	NA	5,689	1,850	4,893	NA
1986	57,517	30,490	3,403	4,805	3,203	4,181	476,983	52,148	NA	6,391	1,905	4,716	NA
1987	63,620	31,314	3,889	5,270	3,432	4,734	496,173	55,279	7,843	7,366	2,009	4,779	NA
1988	69,727	33,728	4,496	5,996	3,684	5,444	529,460	53,555	7,749	7,564	2,147	4,765	NA
1989	74,795	41,902	5,165	6,500	3,909	6,233	523,082	53,414	7,436	8,450	2,270	5,121	NA
1990	79,483	46,509	5,898	6,803	3,974	7,094	546,000	54,068	NA	9,007	2,273	5,129	NA
1991	87,267	50,431	NA	NA	NA	NA	551,106	54,472	NA	9,854	2,375	5,124	NA
							*		**				
Average peak growth rate (1985-1991)	8.8%	11.5%	14.7%	8.2%	5.5%	12.8%	2.9%	0.4%	-2.6%	9.6%	4.3%	0.8%	
Average peak growth rate (1980-1985)	6.4%	6.6%	13.5%	11.9%	4.7%	9.9%	NA	0.7%					
Average energy growth rate (1985-1991)	8.6%	9.2%	17.4%	11.8%	6.1%	13.4%	2.3%	3.1%	5.4%	10.0%	6.0%	2.4%	1.3%
Average energy growth rate (1980-85)	6.5%	8.7%	15.1%	7.7%	4.6%	9.9%	1.6%	-0.4%	3.1%	7.8%	3.7%	5.3%	4.2%

* 5-year growth rate
** 3-year growth rate

Table 7
Consumption by customer class (1980, 1985 & 1991) - GWh

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Net sales 1991	532,901	205,151	27,740	28,935	20,290	36,896	2,762,003	290,841	48,593	49,283	17,550	27,819	105,512
% Consumption by sector													
• Residential	7.9%	15.5%	32.5%	32.0%	31.4%	21.1%	34.6%	33.7%	30.5%	22.0%	0.0%	36.9%	35.0%
• Commercial	5.7%	6.2%	8.4%	6.7%	21.6%	26.8%	27.7%	25.5%	8.5%	6.2%	0.0%	19.8%	18.2%
• Industrial	77.8%	46.9%	51.1%	35.4%	42.9%	48.2%	34.3%	37.6%	48.2%	57.9%	0.0%	40.3%	44.4%
• Transport	1.7%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%	0.6%	0.7%
• Agriculture	6.9%	24.5%	0.0%	18.9%	0.0%	0.3%	0.0%	1.4%	0.0%	0.0%	0.0%	2.5%	0.6%
• Others	0.0%	4.6%	8.1%	7.1%	4.1%	3.5%	3.4%	-0.0%	12.8%	13.9%	0.0%	0.0%	1.2%
Total 1991	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.1%	100.0%
Net sales 1985	354,936	125,992	12,206	15,981	14,770	19,771	2,323,974	244,935	36,860	29,709	12,003	23,994	93,019
% Consumption by sector													
• Residential	0.0%	14.0%	39.7%	28.9%	27.1%	25.3%	34.2%	36.9%	29.6%	16.8%	18.1%	37.5%	33.5%
• Commercial	0.0%	5.9%	9.1%	7.5%	22.1%	25.5%	26.1%	23.9%	10.8%	5.5%	7.6%	17.6%	16.0%
• Industrial	77.5%	54.5%	38.6%	36.0%	43.5%	46.9%	36.0%	35.5%	47.1%	66.0%	46.2%	41.7%	47.2%
• Transport	0.8%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	0.0%	0.0%	2.1%	0.7%	0.8%
• Agriculture	14.2%	19.0%	0.0%	20.4%	0.0%	0.3%	0.0%	1.6%	0.0%	0.0%	0.2%	2.5%	0.9%
• Others	7.6%	4.0%	12.6%	7.2%	7.4%	2.0%	3.8%	0.0%	12.5%	11.7%	25.8%	0.0%	1.7%
Total 1985	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Net sales 1980	259,213	83,704	6,561	10,350	12,637	12,730	2,099,762	249,996	32,884	20,398	10,164		76,031
% Consumption by sector													
• Residential	0.0%	11.2%	44.4%	19.2%	20.7%	22.1%	34.2%	34.4%	30.1%	17.2%	20.3%		31.1%
• Commercial	0.0%	5.7%	14.9%	4.8%	24.4%	27.2%	26.6%	21.6%	10.7%	5.6%	7.0%		13.4%
• Industrial	81.2%	58.4%	26.3%	38.7%	49.3%	50.0%	39.1%	41.2%	47.0%	63.8%	45.9%		51.7%
• Transport	0.5%	2.8%	0.0%	0.0%	0.0%	0.0%	0.1%	1.2%	0.0%	0.0%	2.2%		0.9%
• Agriculture	12.7%	17.6%	0.0%	25.2%	0.0%	0.1%	0.0%	1.6%	0.0%	0.0%	0.2%		0.9%
• Others	5.6%	4.4%	14.5%	12.2%	5.6%	0.6%	0.0%	0.0%	12.2%	13.4%	24.3%		2.0%
Total 1980	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	99.9%		100.0%
Net sales (GWh)													
1980	259,213	83,704	6,561	10,350	12,637	12,730	2,099,762	249,996	32,884	20,398	10,164	NA	76,031
1981	269,184	91,637	7,846	11,256	13,586	13,934	2,144,801	239,067	33,643	22,030	10,489	NA	88,531
1982	283,874	97,202	9,103	13,529	14,535	15,138	2,190,805	238,335	34,420	23,586	10,312	20,104	90,220
1983	302,729	104,363	10,008	14,173	15,484	16,342	2,237,797	233,156	35,215	24,465	10,682	21,371	109,943
1984	326,305	116,466	11,039	15,716	15,305	17,970	2,285,796	241,082	36,028	27,635	11,543	23,027	105,729
1985	354,936	125,992	12,206	15,981	14,770	19,771	2,323,974	244,935	36,860	29,709	12,003	23,994	93,019
1986	390,062	138,959	14,759	19,039	14,926	20,951	2,368,753	257,159	39,590	32,210	12,603	24,275	86,462
1987	426,929	148,592	17,076	21,705	16,589	24,121	2,457,272	263,226	42,523	36,697	13,428	25,349	94,455
1988	474,380	162,878	20,027	25,131	18,601	27,419	2,578,062	274,505	44,457	39,721	14,341	25,805	106,042
1989	508,449	174,906	23,435	26,709	19,866	31,348	2,646,809	279,399	46,479	43,120	15,495	26,698	124,899
1990	541,174	188,240	27,740	28,935	20,290	36,896	2,712,555	284,420	48,593	46,820	16,104	27,309	129,523
1991	532,901	205,151					2,762,003	290,841	52,892	49,283	17,550	27,819	105,512

Table 8
Electricity customers (1990)

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Number of customers 1990 ('000)	242,670	65,760	11,464	7,859	5,386	7,875	110,561	24,754	4,414	15,543	1,679	1,603	NA
Residential	207,240	46,650	10,742	6,209	4,880	7,222	97,095	22,383	NA	12,715	1,512	1,325	NA
Commercial	4,125	7,319	527	1,312	382	542	12,082	1,886	NA	1,823	122	148	NA
Industrial	7,280	1,973	34	181	22	16	525	217	NA	485	18	28	NA
Agriculture	17,715	8,569	0	149	0	16	0	263	NA	0	10	98	NA
Others	6,309	1,249	160	8	102	79	859	5	NA	520	18	5	NA
% of number of customers 1990	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	NA
Residential	85.4%	70.9%	93.7%	79.0%	90.6%	91.7%	87.8%	90.4%	NA	81.8%	90.0%	82.6%	NA
Commercial	1.7%	11.1%	4.6%	15.7%	7.1%	6.9%	10.9%	7.6%	NA	11.7%	7.2%	9.2%	NA
Industrial	3.0%	3.0%	0.3%	2.3%	0.4%	0.2%	0.5%	0.9%	NA	3.1%	1.1%	1.7%	NA
Agriculture	7.3%	13.0%	0.0%	1.9%	0.0%	0.2%	0.0%	1.1%	NA	0.0%	0.6%	6.1%	NA
Others	2.6%	1.9%	1.4%	0.1%	1.9%	1.0%	0.8%	0.0%	NA	3.3%	1.1%	0.3%	NA
Average usage per customer 1990													
Residential	197	625	838	1,492	1,306	1,078	9,517	4,193	NA	714	1,875	7,420	NA
Commercial	1,653	1,589	4,413	1,466	11,461	18,255	62,161	37,551	NA	1,413	10,996	36,861	NA
Industrial	54,711	44,741	411,841	56,667	404,029	1,132,138	1,800,994	509,859	NA	60,276	435,622	405,427	NA
Agriculture	3,562	5,382	0	36,527	0	6,687	0	14,059	NA	0	6,442	6,717	NA
Others	5,103	10,441	14,000	260,669	8,129	16,619	107,087	1,080,796	NA	11,446	219,915	38,233	nA
Population 1991 ('000)	1,151,487	866,352	193,560	117,490	65,759	56,814	252,502	57,515	32,664	58,581	13,390	3,309	4,274
Average size of household	3.67	14.86	4.32	7.00	8.22	5.59	2.60	2.57	NA	0.00	8.06	2.37	NA
% Electrification rate 1990	66.0%	80.0%	24.0%	37.0%	61.0%	71.0%	99.9%[1]	99.9%[1]	95.0%	NA	91.0%	95.0%	97.7%

[1]Assumed.

Table 9
Tariff structure characteristics

	China	*India*	*Indonesia*	*Pakistan*	*Philippines*	*Thailand*	*U.S.*	*U.K.*	*Argentina*	*Turkey*	*Chile*	*New Zealand*	*Norway*
Rates established	National	Regional	National	National	National	National	Regional	Regional	Regional	National	Regional	Regional	Regional
Flat rates for low-voltage users	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Demand & energy components in the rates	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Time of day rates						Yes	Yes	Yes		Yes	Yes	Yes	Yes
Lifeline rates	Yes	Yes		Yes	Yes		Yes	Yes			Yes	Yes	Yes
Fuel adjustment factors	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Relationship to LRMC	below	below	below	below	above	above	above	above	below	below	above	above	above
Price subsidies	agriculture	agriculture		agriculture									
Average tariff increase 1988-91	11.8%	1.9%	6.0%	2.4%	-0.1%	-1.9%	2.7%	1.6%	NA	6.6%	-0.3%	-4.1%	0.7%
Residential tariff increase 1988-91	NA	-4.8%	10.3%	NA	21.7%	0.3%	2.5%	7.5%	7.5%	24.3%	-10.0%	-0.2%	4.6%
Industrial tariff increase (1988-91)	4.9%	3.9%	8.8%	NA	-6.5%	-0.5%	1.7%	-3.7%	-0.2%	3.2%	4.3%	-3.9%	-2.8%

Table 10
Labor situation & productivity

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Number of Employees													
1983	652,863	859,404	44,909	132,000	31,080	59,946	NA	163,748	NA	52,365	0	15,780	17,764
1984	679,739	859,404	49,696	132,000	33,581	63,760	NA	159,080	NA	57,270	0	15,783	17,947
1985	724,584	859,404	51,290	132,000	32,150	64,807	NA	155,280	NA	62,287	3,728	15,592	18,281
1986	771,946	872,577	51,571	132,000	32,550	65,299	NA	153,127	NA	66,683	3,800	15,750	18,801
1987	841,485	897,451	51,203	132,000	35,819	67,827	677,824	152,880	34,480	65,814	3,943	16,388	19,406
1988	842,464	912,032	51,237	132,000	36,754	68,819	675,701	151,507	34,592	68,305	3,939	14,632	19,550
1989	866,516	916,628	51,853	132,000	39,292	71,192	659,871	151,500	34,705	70,408	4,105	13,513	19,560
1990	890,568	921,001	52,812	132,000	42,149	75,045	668,545	151,500	34,818	68,049	3,894	12,922	19,396
1991	1,258,000	NA	NA	NA	NA	NA	NA	148,000	34,932	64,722	3,530	12,588	19,119
Sales per employee (MWh)													
1983	463.7	121.4	222.9	107.4	498.2	272.6	NA	1,423.9	NA	467.2	0.0	1,354.3	6,189.1
1984	480.0	135.5	222.1	119.1	455.8	281.8	NA	1,515.5	NA	482.5	0.0	1,459.0	5,891.2
1985	489.8	146.6	238.0	121.1	459.4	305.1	NA	1,577.4	NA	477.0	3,219.7	1,538.9	5,088.3
1986	505.3	159.3	286.2	144.2	458.6	320.8	NA	1,679.4	NA	483.0	3,316.6	1,541.3	4,598.8
1987	507.4	165.6	333.5	164.4	463.1	355.6	3,625.2	1,721.8	1,233.3	557.6	3,405.5	1,546.8	4,867.3
1988	563.1	178.6	390.9	190.4	506.1	398.4	3,815.4	1,811.8	1,285.2	581.5	3,640.8	1,763.6	5,424.1
1989	586.8	190.8	452.0	202.3	505.6	440.3	4,011.1	NA	1,339.3	612.4	3,774.7	1,975.7	6,385.4
1990	607.7	204.4	525.3	219.2	481.4	481.7	4,057.4	NA	1,395.6	688.0	4,135.6	2,113.4	6,677.8
1991	423.6	NA	NA	NA	NA	NA	NA	1,965.1	1,514.1	761.5	4,971.7	2,210.0	5,518.7
Sales per employee (MWh)	423.6	204.4	525.3	219.2	481.4	491.7	4,057.4	1,965.1	1,514.1	761.5	4,971.7	2,210.0	5,518.7
Customers per employee 1991	242.7	65.8	11.5	7.9	5.4	7.9	110.6	24.8	4.4	15.5	1.7	1.6	0.0

Table 11
Power plant performance in India and the U.S.: 1987-91

Year	Capacity (MW)	Output (GWh)	Planned maintenance %	Forced outage %	Availability %	Plant load factor %	Specific coal use (kg/kWh)	Calorific value (kcal/kg)	Heat rate (kcal/kg)	Station use %	Men per MW
India											
1987-88	29,439	141,473	9.57	17.83	72.60	54.86	0.705	3,838	2,705	10.29	3.782
1988/89	32,354	148,829	11.58	15.44	72.78	52.51	0.700	4,142	2,872	9.92	4.068
1989-90	36,206	168,662	11.06	15.44	73.40	53.18	0.704	4,128	2,901	9.07	3.267
1990-91	37,610	172,713	11.24	16.11	72.21	52.42	0.706	4,091	2,898	7.46	3.251
U.S. (coal plants)											
1987	292,595	1,463,781	12.49	9.07	82.61	57.11	0.438	5,812	NA	NA[1]	0.251
1988	294,685	1,540,653	11.56	8.88	84.03	59.68	0.440	5,804	NA	NA[1]	0.248
1989	296,614	1,553,661	11.03	9.03	84.17	59.79	0.446	5,790	2,593	NA[1]	0.241
1990	279,876	1,559,606	11.24	8.14	84.44	63.61	0.443	5,870	2,615	NA[1]	0.242

[1]Station use data for this subset of plants is not available. It is typically in the range of 5-8%.

Table 12
Thermal plant efficiencies

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
1985	30.5%	29.3%	35.4%	47.2%	32.8%	39.7%	36.7%	37.2%	25.5%	32.3%	37.8%	34.9%	29.9%
1986	30.0%	29.4%	34.5%	44.0%	31.0%	39.9%	37.1%	37.2%	25.9%	31.8%	37.2%	38.5%	21.1%
1987	33.1%	30.3%	30.5%	45.3%	32.4%	39.6%	37.2%	37.6%	25.6%	32.6%	38.1%	37.2%	30.6%
1988	32.1%	28.2%	31.6%	48.6%	31.1%	39.3%	37.9%	37.8%	31.3%	31.6%	38.3%	36.9%	27.5%
1989	31.3%	28.1%	50.9%	41.0%	36.8%	40.1%	37.6%	36.7%	30.2%	34.6%	36.1%	31.7%	48.2%
1990	31.1%	29.4%	32.5%	42.0%	38.7%	36.4%	39.8%	36.9%	31.2%	32.5%	35.7%	43.1%	36.5%
1991	31.7%	29.0%	31.7%	42.7%	36.0%	35.4%	40.0%	37.5%	32.0%	34.1%	54.3%	38.2%	30.7%

Table 13
Structure of production costs

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Salaries & wages as a % of total costs													
1986	4.4%	20.9%	13.4%	3.5%	4.5%	8.4%	10.7%	16.6%	NA	11.2%	NA	NA	11.6%
1987	5.5%	21.0%	12.4%	3.8%	4.8%	8.8%	10.7%	17.6%	NA	16.2%	NA	NA	12.1%
1988	4.0%	21.5%	12.4%	3.4%	5.2%	8.3%	11.0%	16.8%	NA	15.1%	NA	NA	11.8%
1989	4.8%	20.4%	13.6%	3.5%	5.7%	8.6%	10.9%	18.6%	NA	24.1%	NA	NA	12.7%
1990	4.4%	20.1%	12.8%	3.9%	4.2%	8.7%	10.8%	19.9%	NA	40.1%	NA	NA	13.0%
1991	3.9%	20.1%	12.8%	3.9%	4.2%	8.7%	10.8%	19.7%	31.3%	47.2%	NA	NA	12.3%
Fuel & purchased power as a % of total costs													
1986	75.8%	50.3%	74.2%	60.8%	76.1%	64.3%	36.2%	42.0%	NA	54.7%	NA	NA	58.7%
1987	74.7%	51.5%	73.4%	59.1%	71.6%	61.2%	36.8%	40.6%	NA	40.9%	NA	NA	55.9%
1988	70.0%	52.1%	72.9%	60.8%	63.5%	66.2%	37.0%	45.5%	NA	30.1%	NA	NA	56.5%
1989	79.1%	52.8%	69.8%	61.7%	61.0%	64.6%	37.3%	47.8%	NA	35.5%	NA	NA	55.3%
1990	67.3%	52.3%	71.4%	62.2%	67.5%	68.0%	37.2%	47.1%	NA	37.6%	NA	NA	54.9%
1991	67.7%	52.3%	71.4%	62.2%	67.5%	68.0%	36.9%	44.7%	56.1%	39.9%	NA	NA	57.5%
Repairs & maintenance as a % of total costs													
1986	9.7%	5.6%	7.8%	34.2%	3.2%	17.2%	46.5%	36.0%	NA	0.5%	NA	NA	5.8%
1987	11.6%	5.2%	9.6%	35.6%	3.6%	18.2%	45.6%	36.2%	NA	0.5%	NA	NA	5.9%
1988	10.6%	5.4%	9.6%	34.5%	4.2%	17.1%	44.9%	32.2%	NA	0.4%	NA	NA	6.1%
1989	9.4%	5.0%	10.7%	33.4%	6.2%	17.5%	44.8%	28.0%	NA	0.4%	NA	NA	6.3%
1990	16.6%	5.1%	10.7%	32.5%	4.7%	14.9%	44.8%	27.2%	NA	0.6%	NA	NA	6.2%
1991	17.9%	5.1%	10.7%	32.5%	4.7%	14.9%	44.8%	30.1%	11.1%	0.9%	NA	NA	5.8%
Administrative, depreciation, interest, profit, & other costs as a % of total costs													
1986	10.1%	23.2%	4.5%	1.5%	16.2%	10.1%	6.6%	5.4%	NA	33.6%	NA	NA	23.9%
1987	8.2%	22.2%	4.6%	1.5%	20.0%	11.8%	6.9%	5.6%	NA	42.5%	NA	NA	26.1%
1988	15.4%	21.0%	5.1%	1.4%	27.1%	8.4%	7.1%	5.5%	NA	54.4%	NA	NA	25.6%
1989	6.7%	21.8%	5.9%	1.4%	27.1%	9.4%	7.0%	5.7%	NA	40.0%	NA	NA	25.7%
1990	11.7%	22.4%	5.1%	1.4%	23.5%	8.4%	7.3%	5.8%	NA	21.7%	NA	NA	25.9%
1991	10.5%	22.4%	5.1%	1.4%	23.5%	8.4%	7.4%	5.5%	1.5%	12.1%	NA	NA	24.4%

Table 14
Average revenue and unit costs per kWh of sales (U.S.¢ of 1991)

	China	*India*	*Indonesia*	*Pakistan*	*Philippines*	*Thailand*	*U.S.*	*U.K.*	*Argentina*	*Turkey*	*Chile*	*New Zealand*	*Norway*
Average revenue													
1986	11.07	12.61	31.45	26.16	30.08	27.21	7.15	10.58	14.02	24.02	24.46		6.06
1987	10.51	12.40	28.46	23.14	28.62	26.13	6.75	10.08	15.69	17.27	19.18		5.51
1988	9.17	11.79	26.14	24.86	26.56	24.93	6.43	9.84		12.71	18.79	5.43	5.07
1989	9.36	11.78	30.48	26.28	23.30	23.64	6.27	9.76		13.11	18.80	5.33	4.11
1990	10.95	12.15	28.14	26.67	24.72	22.47	6.05	9.32		12.28	19.97	5.23	3.90
1991	12.32	12.80	28.14	26.67	24.72	22.47	6.04	9.43	5.56	12.11	16.40	5.07	5.06
Unit costs													
1986	6.02	14.42	22.07	14.55	16.77	16.25	6.59	10.32		16.87	4.33		4.89
1987	6.08	15.07	21.60	13.28	15.46	14.25	6.12	9.72		14.79	4.64		4.48
1988	5.74	14.54	19.63	13.88	12.25	13.76	5.80	9.79		12.58	12.89	5.16	4.11
1989	6.16	15.38	17.72	13.69	11.42	12.80	5.67	8.71		14.73	12.80	4.29	3.19
1990	8.49	14.86	19.50	13.28	14.23	11.92	5.48	7.76		10.71	14.00	4.20	2.97
1991	9.64	15.74	19.50	13.28	14.23	11.92	5.44	7.55	6.04	10.89	9.61	4.36	3.81

Deflated with the CPI (1991=100) and with the 1991 PPPER.

Table 15
Indian power sector

Year	*Annual peak demand*	*Installed capacity*	*Customer sales*	*T&D losses*	*High-voltage network (>132 kV)*	*Low-voltage network (<132 kV)*	*Total T&D*
1980	19,089	30,213	83,704	21,325	88.533	2,263,076	2,351,609
1981	20.121	32,345	91,637	23,389	93,912	2,428,549	2,522,461
1982	21,527	35,363	97,202	25,644	101,187	2,591,899	2,693,086
1983	23,077	39,353	104,363	27,689	106,733	2,758,579	2,865,312
1984	24,020	42,618	116,466	31,214	114,245	2,887,850	3,002,095
1985	26,248	46,803	125,992	34,194	125,204	3,086,752	3,211,956
1986	30,490	49,287	138,959	37,784	131,834	3,239,382	3,371,216
1987	31,314	54,176	148,592	42,231	137,727	3,434,733	3,572,460
1988	33,728	59,060	162,878	46,032	143,489	3,648,618	3,792,107
1989	41,902	63,011	174,906	53,260	150,419	3,891,603	4,042,022
1990	46,509	66,257	188,240	57,320	157,694	4,249,807	4,407,501
1991	50,431	69,025	205,151	61,173			
Annual growth 1980-1985	6.6%	9.1%	8.5%	9.9%	7.2%	6.4%	6.4%
Annual growth 1985-1991	11.5%	6.7%	8.5%	10.2%	4.7%	6.6%	6.5%

Table 16
Investment and financial performance

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
1991 Capital investment $U.S. (1991)	5,936	3,783	906	676	189	7.103	14.674	6,281	3,919	1,171	186	6,216	870
Average capital investment 1986-1991[1]	4,906	4,444	1,163	699	254	5,270	14,674	4,788	3,919	1,622	454	5,514	1,269
• Investment/GDP (¢ 1991)	1.56	1.62	0.86	1.57	0.43	8.27	0.27	0.62	2.18	1.08	0.79	14.66	0.82
• Investment/capacity ($/MW 1991)	39.2	57.1	97.9	96.4	30.5	884.9	21.3	85.9	254.9	68.1	49.8	879.6	32.1
• Investment/net sales ($/MWh 1991)	11.1	20.1	32.7	25.8	9.3	192.5	5.4	21.6	80.7	23.8	14.1	223.4	8.2
Operating margin (rev - costs)/rev	21.2%	-0.8%	32.7%	51.7%	44.5%	50.2%	17.6%	19.9%	-4.9%	11.5%	42.0%	NA	34.0%
Rate of return	4.0%	0.8%	6.3%	10.1%	6.6%	6.6%	1.7%	1.6%	-13.4%	3.0%	0.0%	8.1%	0.0%

[1]Deflated with the WPI (1991=100).
Note: U.S.$ estimates based on 1991 official exchange rates.

Table 17
Memorandum items: foreign exchange rates and price indices

	China	India	Indonesia	Pakistan	Philippines	Thailand	U.S.	U.K.	Argentina	Turkey	Chile	New Zealand	Norway
Consumer price indices													
1980	44.1	37.6	40.3	45.7	22.8	61.5	60.5	50.1	0.0	1.4	12.9	35.3	46.4
1981	45.3	42.5	45.2	15.1	25.8	69.3	66.7	56.0	0.0	1.9	15.5	40.8	52.7
1982	46.2	45.9	49.5	54.1	28.4	72.9	70.9	60.8	0.0	2.5	17.0	47.4	58.6
1983	47.1	51.3	55.3	57.6	31.2	75.7	73.1	63.6	0.0	3.3	21.6	50.9	63.6
1984	48.4	55.5	61.2	61.1	47.0	76.3	76.3	66.8	0.0	4.9	25.9	54.0	67.6
1985	54.1	58.7	64.1	64.5	57.8	78.2	79.0	70.8	0.0	7.1	33.9	62.4	71.4
1986	57.9	63.8	67.8	66.8	58.3	79.6	80.5	73.2	0.0	9.5	40.5	70.6	76.6
1987	63.0	69.4	74.1	69.9	60.5	81.6	83.5	76.3	0.0	13.3	48.5	81.7	83.2
1988	76.0	75.9	80.0	76.1	65.8	84.8	86.8	80.0	0.0	23.0	55.7	86.9	88.8
1989	88.4	80.7	85.2	82.1	73.8	89.3	91.0	86.3	1.5	37.6	65.2	91.9	92.9
1990	89.5	87.8	91.5	89.5	84.3	94.6	95.9	94.5	36.8	60.2	82.0	97.5	96.7
1991	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 17 (continued)
Memorandum items: foreign exchange rates and price indices

	China	*India*	*Indonesia*	*Pakistan*	*Philippines*	*Thailand*	*U.S.*	*U.K.*	*Argentina*	*Turkey*	*Chile*	*New Zealand*	*Norway*
Wholesale price indices													
1980	52.8	44.4	38.0	42.5	20.4	69.4	77.1	54.2	0.0	1.8	12.8	42.0	55.6
1981	53.8	49.9	42.2	47.2	23.4	76.0	84.1	59.4	0.0	2.5	14.0	49.2	61.8
1982	53.7	51.0	45.3	50.4	25.9	76.6	85.8	64.0	0.0	3.2	15.1	56.5	65.8
1983	54.3	55.1	53.4	54.1	30.0	78.2	86.9	67.5	0.0	4.2	21.7	59.6	69.7
1984	57.1	58.9	59.3	59.1	50.2	75.8	89.0	71.4	0.0	6.2	27.1	63.9	74.0
1985	62.5	61.7	62.2	60.8	59.4	75.8	88.6	75.1	0.0	9.0	38.8	73.7	77.8
1986	65.0	65.1	63.6	63.8	58.4	75.5	86.0	78.4	0.0	11.6	46.5	77.9	79.9
1987	69.8	69.6	75.9	69.1	63.8	80.0	88.3	81.4	0.0	15.3	55.4	84.1	84.7
1988	79.1	75.6	79.6	75.9	72.3	86.5	91.1	85.0	0.1	25.8	58.5	88.5	89.2
1989	85.6	80.8	86.4	82.2	80.0	90.5	96.4	89.4	2.0	42.3	67.4	94.8	94.0
1990	89.5	88.1	95.1	89.3	88.1	93.6	99.8	94.7	41.5	64.4	82.2	99.2	97.5
1991	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Power parity exchange rates													
1980	0.846	3.876	268.628	3.360	2.971	8.109	1.000	0.432	0.000	48.403	23.079	0.920	7.473
1981	0.906	4.306	273.553	3.320	3.164	8.459	1.000	0.538	0.000	65.532	24.879	1.025	8.618
1982	0.885	4.465	305.977	3.419	3.319	8.462	1.000	0.602	0.000	79.040	35.512	1.113	9.260
1983	0.817	4.371	378.151	4.256	3.902	8.145	1.000	0.611	0.000	94.537	40.210	1.139	9.508
1984	0.838	4.750	377.090	4.132	5.334	7.907	1.000	0.612	0.000	134.053	39.183	1.192	9.737
1985	0.925	4.732	364.300	4.186	5.613	8.333	1.000	0.578	0.000	174.713	53.096	1.252	9.613
1986	0.903	4.693	379.969	4.240	6.038	7.525	1.000	0.506	0.000	213.495	57.583	1.196	8.224
1987	0.866	4.809	423.487	4.124	6.086	7.123	1.000	0.489	0.000	274.903	63.227	1.179	7.982
1988	0.839	5.254	402.264	3.994	6.187	7.385	1.000	0.511	0.001	457.511	73.306	1.282	8.471
1989	0.863	5.766	398.693	4.329	6.554	7.785	1.000	0.590	0.025	697.054	84.362	1.533	9.422
1990	1.052	5.918	415.529	4.700	7.412	7.868	1.000	0.568	0.330	924.011	99.580	1.580	8.908
1991	1.062	7.173	439.328	4.613	8.421	7.938	1.000	0.583	0.700	1,565.230	115.853	1.561	8.328
Market exchange rates													
1980	1.498	7.863	626.990	9.900	7.511	20.476	1.000	0.430	0.000	76.040	39.000	1.026	4.939
1981	1.705	8.659	631.760	9.900	7.900	21.820	1.000	0.493	0.000	111.220	39.000	1.149	5.740
1982	1.893	9.455	661.420	11.847	8.540	23.000	1.000	0.571	0.000	162.550	50.909	1.330	6.454
1983	1.976	10.099	909.260	13.117	11.113	23.000	1.000	0.659	0.000	225.460	78.842	1.495	7.296
1984	2.320	11.363	1,025.940	14.046	16.699	23.639	1.000	0.748	0.000	366.680	98.656	1.729	8.162
1985	2.937	12.369	1,110.580	15.928	18.607	27.159	1.000	0.771	0.000	521.980	161.081	2.006	8.597
1986	3.453	12.611	1,282.600	16.648	20.386	26.299	1.000	0.682	0.000	674.500	193.020	1.900	7.397
1987	3.722	12.962	1,643.800	17.399	20.568	25.723	1.000	0.610	0.000	857.200	219.540	1.689	6.738
1988	3.722	13.917	1,685.700	18.003	21.095	25.294	1.000	0.561	0.001	1,422.300	245.050	1.524	6.517
1989	3.765	16.226	1,770.100	20.541	21.737	25.702	1.000	0.610	0.042	2,121.700	267.160	1.671	6.905
1990	4.783	17.504	1,842.800	21.707	24.311	25.585	1.000	0.560	0.488	2,608.600	305.060	1.675	6.260
1991	5.323	22.742	1,950.300	23.801	27.479	25.517	1.000	0.565	0.924	4,171.800	349.370	1.727	6.483

Performance of the power sector in India

by
Tata Energy Research Institute

1. Introduction

The Power Sector in India, with a total installed capacity of nearly 70,000 MW, is one of the largest in size in the world. The sector has undergone a substantial change during the past four decades, both in terms of its size, as well as in terms of the regulatory structure. The installed power generating capacity and gross generation increased at 9 percent and 10.2 percent (compounded) respectively during the period 1950/51 to 1992/93. This growth has been achieved largely through investments made by the government in the successive Plans. The Plan allocation for the Power Sector has varied between 17 percent and 18 percent of the total Plan outlay, and in absolute terms, the outlay has been doubling every ten years. In the Eighth Plan (1992-97), 24 percent of the total outlay has been allocated for the Power Sector.

Though the progress of the Power Sector during the past four decades has been substantial in absolute terms, the industry has been unable to fulfil the primary obligation of providing quality power in the required quantities to the different consumer categories. Both peak and energy shortages of varying degrees are prevalent in various parts of the country. The SEBs, who are responsible for generating and supplying power in the most efficient and economic manner in their states, are today caught in a vicious circle of shortage of resources and poor operational and financial performance. Resource constraints not only lead to delays in capacity additions and thereby increased cost of power generation, but also affect the performance of existing capacities. Rising costs of power supply and unrationalized tariffs, primarily due to social and political considerations of the state governments, have resulted in huge levels of accumulated losses in the Boards.

The existing inefficiencies and problems in the Power Sector are a function of a large number of variables, ranging from those which are directly under control of the Boards, to those which are related to the existing institutional and management framework. Lack of transparency and political interference is perhaps the root cause of the deteriorating performance of the Power Sector. This paper attempts to review the performance of the Power Sector in India, at the

national and state levels. The performance of the Boards is also compared with the other public and private utilities operating in the country. The objective is to highlight some of the major issues and constraints within which the system is operating today, with a view to initiate discussions to identify workable solutions for the same.

2. Growth of the power sector

2.1 *Installed capacity*

The generating capacity in India comprises a mix of hydro, coal-based thermal, oil-fired thermal, gas and nuclear plants. Total installed capacity has increased at a growth rate of 9 percent per annum during the period 1950/51 to 1992/93, and as of March 1993, stands at 69,796 MW. Among the five regions, the growth rate in installed capacity has been highest in the Northern region and lowest in the Eastern region. The growth in installed capacity is characterized by:

- Declining hydrothermal capacity mix since the early seventies. The share of hydro power projects in the total installed capacity increased from 32.6 percent in 1950 to 45.6 percent by the end of the Third Plan (1960-65) and declined to 28 percent in 1991-92 (Figure 1). Hydroelectric generation facilities are dominant in the Southern and the Northeastern regions (Annex 1).
- Only 14 percent of the total hydroelectric potential (84,000 MW at 60 percent load factor) has been developed so far, and 7.1 percent is under various stages of development. Maximum unexploited potential lies in the Northern and Northeastern region.
- The share of gas-based installed capacity at only 2.7 percent, is concentrated in the Northeastern and Western regions. It is estimated that over 4 bcm of natural gas being flared in the Bombay High basin annually can generate about 12,000 MWh of electricity.
- Nuclear capacity of 1,500 MW installed in the Northern, Western, and Southern regions, accounting for only 2.3 percent of the installed capacity.
- Rising share of central generating companies in the total installed capacity, from 7.3 percent in 1980/81 to 22 percent in 1989/90 (Figure 2). The increasing trend in the share of investment by the public sector generating companies in setting up new generation capacities is evident from Figure 3. Further it is important to note that the central generating companies have realized better plan-wise achievements in installed capacity compared to the SEBs.

Figure 1
Trends in installed capacity

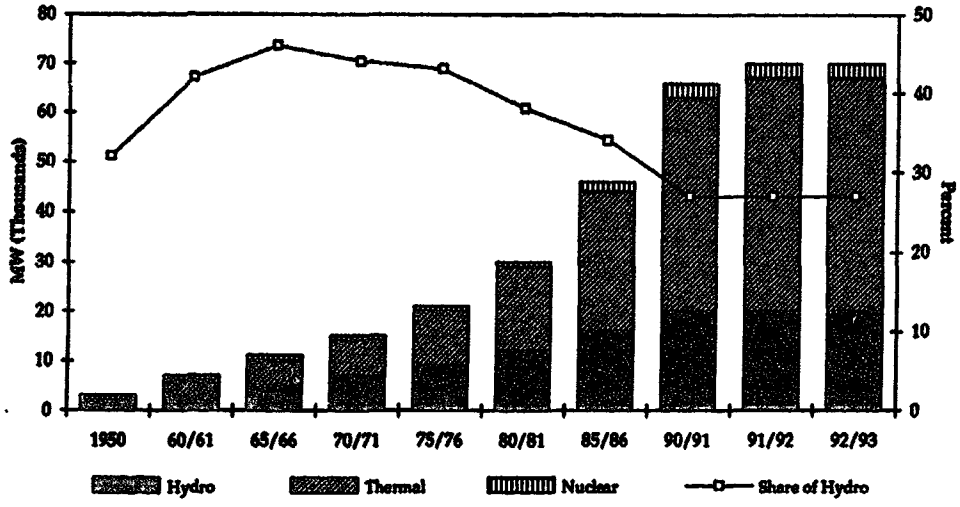
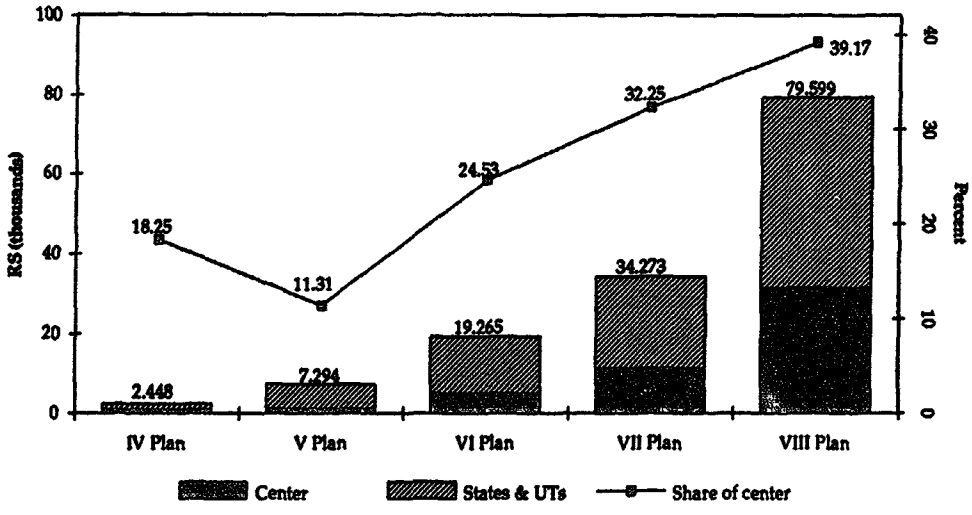


Figure 2
Ownership of installed capacity

ED: Electricity department

Figure 3
Investments in the power sector



- About 4 percent of the total installed capacity is owned by the private companies. Their share, however, is expected to increase in the future with the opening up of the power sector for private sector participation in power generation and distribution.
- Increase in the unit size of coal-fired thermal power plants affording economies of scale. While in 1960, the largest size in use was a set of 90 MW, today 210 MW and 500 MW sets have become common.
- A shift in the location of the power stations from load center to pit head locations, in view of the problems of transportation of large quantities of coal from pit head to stations located at the load center. The share of pit-head capacity in the total installed thermal generation capacity has progressively increased from 10 percent at the end of the Sixth Plan to 25 percent at the end of the Seventh Plan (1985-90).

In the Eighth and Ninth Five-Year Plans, 70,000 MW of new capacity is envisaged to be commissioned. While coal-based generation will continue to be the mainstay of the Indian power sector, it is important to improve the peaking availability through increased share of hydro and gas capacities. Large hydro projects have faced several problems on the environmental front and these concerns need to be rationally viewed and some major sites should be carefully selected for early development. Further, the possibilities of developing hydro resources with collaboration and cooperation of neighboring countries, such as Nepal and Bhutan, need to be explored. The use of gas for power generation has to be carefully evaluated considering its availability and its alternative uses based on the value added potential in other sectors of the economy like fertilizers, petrochemicals, transportation, etc. Seven new units, of 235 MW each, of nuclear capacity are under construction, and the Department of Atomic Energy (DAE) plans to add 5,000 MW of nuclear capacity by the turn of the century. This targeted capacity however, may not be achievable in light of the various technical and financial constraints. Also long-term waste management and the eventual decommissioning of plants will be the two key concerns in the development of nuclear power.

2.2 *Generation*

In line with additions to installed capacity, gross generation in public utilities also increased rapidly, from 5.1 TWh in 1950 to 301 TWh in 1992/93, registering a compounded growth rate of 10.2 percent per annum (Figure 4). During the eighties, the hydro generation increased at only 4.4 percent as against 11.6 percent for thermal generation. This may be attributed to a decline in the share of hydro capacity in the total capacity mix as well as a gradual reduction in the average utilization of the hydro projects (from 45.15 percent in 1970/71 to 34.78 percent in 1988/89). Owing to poor hydro development and prevailing peak deficits, coal-fired thermal power units are often used for meeting peak loads. Since the start-up time for a coal-fired thermal power unit is four to five hours, these units have to continue generating at part load conditions during the night hours (when the demand is low); this reduces their overall efficiency. Nuclear generation has accounted for 2.5-2.7 percent of the total generation since the seventies. The capacity utilization of nuclear power stations has also declined from 65.7 percent in 1970/71 to 49.8 percent in 1988/89. Region-wise and source-wise gross generation in utilities is given in Annex 2. The share of gross generation by the central generating companies, has increased from 7.7 percent in 1980/81 to 25 percent in 1989/90.

2.3 *Transmission and distribution*

The basic transmission and distribution (T&D) configuration today is a 400 kV network as the main and bulk transmission system in each

Figure 4
Trends in power generation

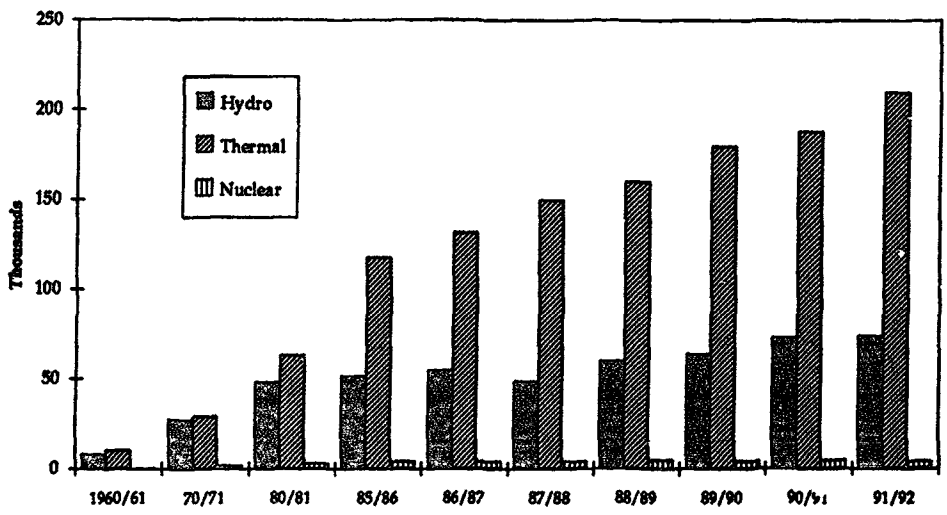
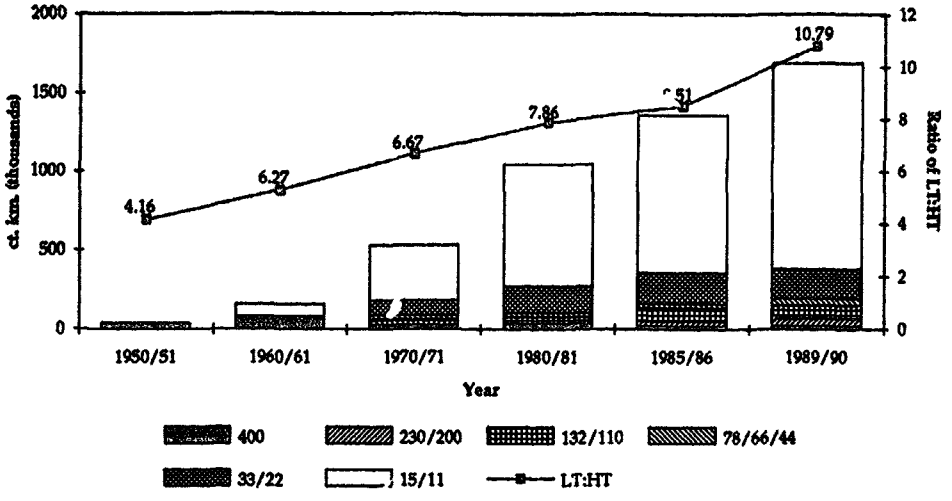


Figure 5
Growth of T&D network



region; 220 KV, 132 KV and 110 KV network as the main and support transmission systems in each state; 66 KV, 33 KV and 22 KV network as subtransmission systems; 11 KV network as primary distribution systems; and 400 V (three-phase) and 230 V network as local distribution systems. The total T&D network expanded by about 6.4 percent per annum during the 1980s (Figure 5). One of the striking features of the expanding T&D network is the rising share of 11 KV distribution lines. The ratio of LT:HT lines increased from 4.16 in 1965/66 to 7.86 in 1980/81 and further to 10.79 in 1989/90.

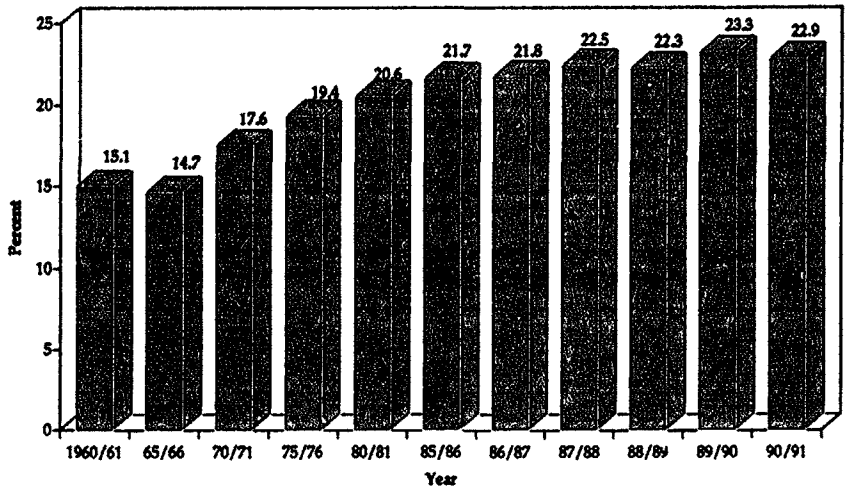
In the past, the investments in the T&D system have generally been less than the desired levels. Investment in generation has always gained priority over investment in T&D, indicating priority on quantity rather than quality of electricity supply. Investment in generation in most of the utilities has varied between 60 percent and 62 percent of the total Plan allocation, as against the recommendation of 50 percent by the Rajayadhaksha Committee (1980). Another aspect that needs attention, is that at present, transmission and generation planning is not done simultaneously and in a coordinated manner. As a result, for example, the generation levels of certain power stations (for example, Singrauli and Rihand Thermal Power Station in the Northern region) had to be curtailed because not all the required 400 KV lines had been commissioned to evacuate the power generated.

While the interstate power exchanges are quite common, interregional exchanges are constrained due to lack of adequate transmission facilities. The major emphasis hitherto has been to use AC technology. HVDC technology is being introduced for back-to-back interconnection between the Northern and Western regional systems and also for the bulk transfer of power in the Northern region. Until now one HVDC line has been established between Singrauli and Dadri in the Northern region, for bulk transfer of power to the Delhi area from the Singrauli area in central India where there is a concentration of pit-head super thermal power stations. With the rising share of central sector in total installed capacity[1], there is a need to strengthen the facilities for interregional exchanges to utilize available power effectively to reduce the shortages. In addition to transmission facilities, there is an urgent need to look into issues relating to interstate and interregional tariffs.

High T&D losses is one of the important issues of concern for the Indian utilities. T&D losses in the Indian utilities increased from 17.5 percent in 1970/71 to 23 percent in 1992/93 (Figure 6). Losses are particularly high in the Northeastern states, averaging 32 percent in 1989-90 as against

[1] All the central sector coal-based power stations are of unit capacities of 210 MW or 500 MW and have ultimate station capacities of 2,000 MW.

Figure 6
Trends in T&D losses



all-India figure of 22 percent.[2] Apart from the technical losses, the incidence of nontechnical losses is quite high in several utilities on account of pilferage and unmetered supply.[3] The reasons for high T&D losses (technical) include:

- Weak and inadequate subtransmission and distribution system due to low priority given to these works as compared to the generation projects
- Large-scale rural electrification program undertaken in the country, resulting in long lines and low power factor without strengthening the back up transmission and subtransmission system
- Too many transformation stages, resulting in higher component of transformer losses
- Inadequate reactive compensation in the system
- Improper load distribution, resulting in overloading of system.

Reduction in technical losses require transmitting at higher voltages and appropriate HT:LT ratio. In the lower voltage networks, in addition to the augmentation of the network, installation of capacitors, reconductoring, eliminating both underloading and overloading of distribution transformers is required to reduce technical losses. Reduction in T&D losses is a priority area in the Eighth Five-Year Plan. System improvement schemes are also high on the priority list of the Power Finance Corporation for granting loans.

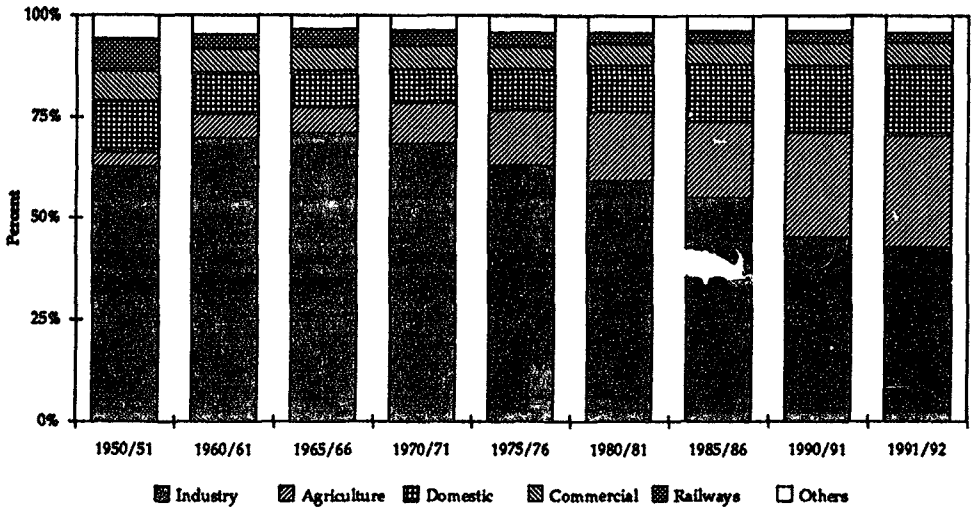
Curtailment of nontechnical losses requires a judicious mix of legislative support, increased customer awareness, improved billing and collection procedures and reliable and high quality meters.

2.4 *Rural electrification*

Rural electrification (RE) as a plan program was introduced in the First Plan with the objective to provide electricity as a social amenity to rural areas. Both the central and the state governments give high priority to RE programs. The primary objective is to ensure increased agriculture output by providing power for irrigation pumpsets. A secondary objective is to provide electricity for domestic, commercial and small industrial consumers and the street lighting in the villages, thereby improving employment opportunities and the quality of life in the rural areas. The RE program was strengthened by the formation of Rural Electrification Corporation

[2] A substantial portion of the electricity sold is not metered and thus the T&D loss figure should be taken as estimated value.
[3] A study conducted by TERI for the Delhi Electric Supply Undertaking (DESU), estimated that the total T&D losses in the DESU network comprise about 13 percent technical losses and 9 percent commercial losses.

Figure 7
Sectoral electricity consumption



(REC) in 1969 which now provides over 90 percent of the funds for rural electrification as concessional loans to the SEBs. As a result of these efforts, today 84 percent of the Indian villages have been electrified and nearly 10 lakhs pumpset energized (Annex 3). The achievement of RE has been maximum in the Southern region.

Though the progress of RE program looks quite impressive in terms of quantum of villages electrified, the fact remains that so far only about 27 percent of rural households have been electrified, as electrification of a village (as per current definition) implies that only one or more households in the village have this facility. Further, the low tariff charged for the sale of electricity to the agriculture sector has not only resulted in heavy financial losses to SEBs but has led to the wasteful use of electricity and also of underground water. The flat rate tariff structure offers no incentive for energy conservation. The RE program has also resulted in an increase in T&D losses in the power system due to the extension of the LT supply network in a sub-optimal manner.

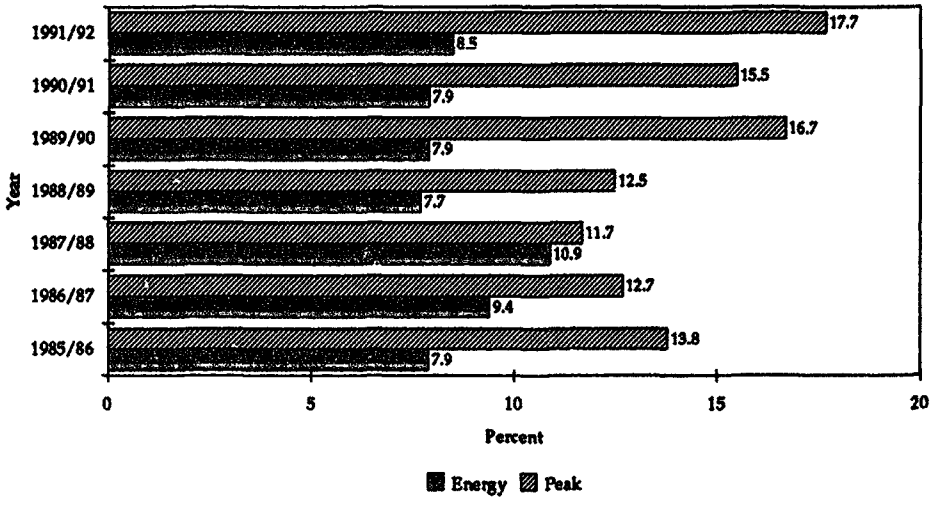
2.5 *Trends in electricity consumption*

Though the per capita consumption of electricity in India is quite low, 253 KWh in 1990/91, the demand for electricity has been increasing at a fast rate outstripping its availability. Electricity consumption has grown at an annual compound rate of 10 percent during the period 1950 to 1991/92. The pattern of consumption has undergone a significant structural change during the past four decades, with the increase in the share of agriculture and domestic sector in total electricity consumption. The RE program launched by the government in the mid-sixties resulted in a large-scale energization of pumpsets. This compounded by subsidized electricity tariffs has lead to a rapid increase in electricity consumption in the agriculture sector. Consequently, the share of agriculture sector in total electricity consumption has increased from 7 percent in 1965/66 to 28.2 percent in 1991/92 (Figure 7). In some states like Punjab, Haryana, Uttar Pradesh and Andhra Pradesh nearly 35-40 percent of the total electricity consumption is for irrigation purposes.

The electricity consumption by the domestic sector increased at a compounded growth rate of about 10 percent per annum during the last four years resulting in almost doubling of its share in total electricity consumption. Increased urbanization and increased use of domestic electric appliances are perhaps the reasons for such a trend.

The industrial sector, though still accounting for the highest share in total electricity consumption, registered a decline in its share in total utility electricity consumption from 70.6 percent in 1965/66 to 42 percent in 1991/92. A large number of industries are increasingly relying on captive power because of increasing

Figure 8
Electricity shortages



shortages of the utility power and also poor quality of supply. Number of industries having captive power plants (capacity 500 KV or 100 KW or more) increased from 828 units in 1950 to 3,648 units in 1985/86. In 1989/90, a survey of 1,304 industries showed that captive power generation accounted for nearly 42 percent of their total electricity consumption.

The commercial sector, comprising shops, offices, institutions, hotels, etc., continues to account for 5-6 percent of the total electricity sales. Today electricity is also finding greater use in the transport sector, largely in the railways. Electricity consumption in railways though accounting for only 2.3 percent of the total electricity consumption has increased from 372 MWh in 1970/71 to 5,338 MWh in 1989/90, an annual growth rate of 15 percent.

2.6 *Demand supply gap*

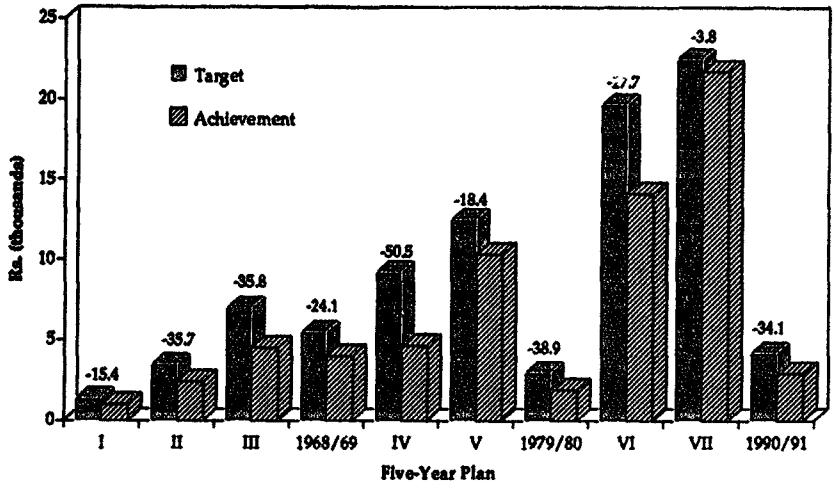
Power supply position in India has moved from one of surplus in the fifties and sixties to one of deficit since the mid-seventies. Both peak and energy shortages of varying degree are prevalent in the various states. In 1991/92, the all-India peak and energy deficit was 17.7 percent and 8.5 percent, respectively (Figure 8). Except in the Northern region, the demand-supply gap has deteriorated in all the other regions.

The situation is most critical in the Eastern and Southern regions (Table 1). Discussions reveal that energy shortages could be reduced partially if there existed adequate economic and technical provisions for interstate and interregional power exchanges.

Table 1
Regionwise trends in energy shortages (%)

Region	*1984/85*	*1985/86*	*1986/87*	*1987/88*	*1988/89*	*1989/90*	*1990/91*
Northern	14.0	10.7	9.5	11.3	5.9	5.8	5.4
Western	0.7	1.4	4.2	4.9	2.6	2.6	3.6
Southern	-0.2	9.3	11.0	16.9	13.8	13.3	10.9
Eastern	17.3	13.8	17.7	12.2	11.6	15.0	18.5
Northeastern	-2.4	3.6	6.2	4.8	3.2	3.0	4.6
All-India	6.7	7.9	9.4	10.9	7.7	7.9	7.9

Figure 9
Slippages in installed capacity



Figures indicate percent slippage

Perhaps the key reason of such shortages is the insufficiency of financial resources. As against the estimated requirement of Rs. 128,000 crores for the Power Sector development in the Eighth Plan, the Plan allocation was only Rs. 79,589 crores. Inadequate resources and poor project management and implementation result in slippage in capacity additions, thus widening the demand supply gap (Figure 9). Further, low plant load factor, poor availability of power plants, high T&D losses on the supply side, and low end-use efficiencies also aggravate shortages.

Annex 1
Installed capacity in utilities by region as on March 31 of each year (%)

	1971	1977	1980	1984	1987	1989	1990
Northern region (MW)	**3,152.55**	**5,634.28**	**8,224.02**	**11,179.78**	**13,462.44**	**17,470.97**	**19,138.17**
Hydro	61.37	47.90	47.99	42.68	38.79	34.14	31.45
Steam thermal	34.83	45.91	48.36	52.85	56.32	59.06	58.55
Diesel and wind	3.40	1.89	0.83	0.54	0.36	0.12	0.11
Gas	0.40	0.40	0.15	0.00	1.34	2.82	6.36
Nuclear	0.00	3.90	2.68	3.94	3.27	3.86	3.53
Western region (MW)	**4,023.83**	**5,607.05**	**7,808.52**	**11,975.00**	**14,680.63**	**17,818.31**	**19,211.59**
Hydro	28.12	29.75	22.93	15.12	14.19	12.51	12.00
Steam thermal	59.09	61.71	70.96	78.90	77.98	81.03	81.92
Diesel and wind	1.02	0.08	0.04	0.02	0.02	0.02	0.11
Gas	1.34	0.96	0.69	2.46	4.95	4.07	3.78
Nuclear	10.44	7.49	5.38	3.51	2.86	2.36	2.19
Southern region (MW)	**4,034.71**	**5,634.22**	**7,207.31**	**9,397.81**	**12,488.55**	**14,567.19**	**15,866.06**
Hydro	70.40	66.72	63.73	63.13	59.99	54.49	51.02
Steam thermal	29.04	32.88	35.97	33.60	36.21	42.24	45.9
Diesel and wind	0.07	0.05	0.02	0.02	0.03	0.05	0.12
Gas	0.50	0.35	0.28	0.21	0.00	0.00	0.00
Nuclear	0.00	0.00	0.00	2.50	3.76	3.23	2.96
Eastern region (MW)	**3,305.47**	**4,327.52**	**4,866.74**	**6,076.88**	**7,741.42**	**8,161.21**	**8,380.81**
Hydro	12.39	18.95	18.63	16.13	13.96	15.23	17.46
Steam thermal	86.56	80.16	16.81	81.44	84.15	81.82	79.67
Diesel and wind	1.06	0.89	0.86	0.78	0.61	0.61	0.60
Gas	0.00	0.00	2.05	1.65	1.29	2.33	2.27
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northeastern region (MW)	**192.39**	**265.52**	**341.24**	**709.39**	**892.82**	**1,022.00**	**1,039.71**
Hydro	34.99	29.67	43.13	43.81	35.62	41.23	40.73
Steam thermal	0.00	24.48	18.32	26.08	36.63	34.93	32.22
Diesel and wind	22.65	15.16	14.67	9.32	8.43	6.96	6.95
Gas	42.36	30.69	23.88	20.79	19.32	16.88	20.10
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00
All India (MW)	**14,708.95**	**21,468.59**	**28,447.83**	**39,338.86**	**49,265.86**	**59,039.68**	**63,636.34**

Annex 2
Regionwise annual gross generation in utilities (GWh)

	1970/71	1976/77	1979/80	1982/83	1985/86	1986/87	1987/88	1988/89
Northern region	**11,863.00**	**23,858.00**	**29,227.00**	**37,077.00**	**46,134.00**	**53,147.00**	**59,994.00**	**75,560.00**
Hydro	55.77	48.05	52.95	49.99	42.66	41.44	34.78	33.10
Steam	43.93	47.31	43.15	48.52	54.55	55.79	62.15	60.83
Diesel	0.30	0.04	0.02	0.01	0.00	0.00	0.00	0.00
Gas	0.00	0.01	0.01	0.00	0.00	0.28	0.75	3.78
Nuclear	0.00	4.59	3.87	1.49	2.80	2.49	2.32	2.29
Western region	**16,912.00**	**25,981.00**	**32,077.00**	**40,188.00**	**57,376.00**	**62,733.00**	**68,471.00**	**81,490.00**
Hydro	32.39	29.45	24.77	16.30	10.36	9.81	7.40	8.43
Steam	52.89	61.85	69.55	77.19	84.26	82.89	86.51	86.56
Diesel	0.09	0.00	0.00	0.00	0.00	0.00	0.00*	0.00*
Gas	0.34	0.40	0.24	2.85	1.97	4.11	3.74	3.12
Nuclear	14.29	8.30	5.44	3.66	3.42	3.19	2.34	1.89
Southern region	**15,710.00**	**21,714.00**	**27,032.00**	**33,682.00**	**43,496.00**	**46,875.00**	**47,457.00**	**59,917.00**
Hydro	74.34	60.22	71.60	60.11	49.11	44.96	36.57	40.96
Steam	25.65	39.77	28.40	39.88	46.91	51.40	59.13	56.77
Diesel	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02
Gas	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear	0.00	0.00	0.00	0.00	3.98	3.62	4.29	2.25
Eastern region	**10,959.00**	**15,977.00**	**15,393.00**	**17,922.00**	**21,167.00**	**22,982.00**	**23,958.00**	**25,664.00**
Hydro	12.01	15.37	15.16	14.30	13.98	15.97	13.33	16.02
Steam	87.70	84.55	83.99	84.41	85.78	83.76	86.43	83.42
Diesel	0.29	0.07	0.18	0.11	0.00	0.10	0.13	0.14
Gas	0.00	0.00	0.66	1.18	0.23	0.17	0.12	0.42
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northeastern region	**385.00**	**803.00**	**898.00**	**1,395.00**	**1,897.00**	**1,980.00**	**2,213.00**	**2,807.00**
Hydro					54.24	46.52	43.77	56.40
Steam					14.31	23.21	23.57	25.72
Diesel					1.25	1.42	1.35	1.43
Gas					30.20	28.85	31.31	16.45
All India	**55,829.00**	**88,333.00**	**104,627.00**	**130,264.00**	**170,010.00**	**187,717.00**	**202,094.00**	**245,438.00**

*Includes 1.56 GWh from windmills

Annex 3
Progress of rural electrification

	Villages electrified		Pumpsets energized
	('000s)	% of total no. of villages	
1950-51	3	0.5	21
1960-61	22	3.8	199
1968-69	74	12.8	1,089
1973-74	157	27.2	2,426
1977-78	217	37.6	3,300
1978-79	233	40.4	3,599
1979-80	250	43.4	3,966
1984-85	370	64.3	5,709
1989-90	470	81.3	8,308
1990-91	482	83.7	8,972

Annex 4
Performance of thermal power stations in various capacity groups

	Commissioned up to 31-3-91		Reviewed during 1990-91		PLF (%)		
Capacity	No.	Capacity (MW)	No.	Capacity (MW)	1988-89	1989-90	1990-91
500	13	6,500	11	5,500	74.97	70.03	61.02
200/210	101	21,090	90	18,780	60.65	61.71	60.24
140/150	9	1,270	9	1,270	42.74	49.24	40.94
115/120	20	2,380	20	2,380	38.73	41.62	41.87
105/110	39	4,245	37	4,025	47.20	45.92	37.98
90/100	11	1,042	11	1,042	52.23	53.38	57.61
70/80	9	680	8	610	32.96	35.66	27.34
62.5/67.5	22	1,375	22	1,375	51.22	54.23	51.78
60	25	1,485	25	1,485	47.86	45.78	44.57
40/55	29	1,275	28	1,225	49.36	51.12	51.29
20/32	33	840	23	606	41.84	36.18	36.66
Total	**311**	**42,182**	**284**	**38,298**	**54.93**	**56.22**	**53.89**

Annex 5
Quality of coal received at thermal power stations

Year	Avg. calorific value (kcal/kg)	Percentage receipt of coal in various grades						% of (E+F+G) grade
		B	C	D	E	F	G	
1985-86	4,217	1.7	1.6	19.8	26.9	41.2	8.8	76.9
1986-87	4,075	1.5	1.3	17.7	20.1	48.6	10.8	79.5
1987-88	3,800	1.3	1.1	20.2	27.0	41.4	9.0	77.4
1988-89	4,179	1.13	0.04	15.1	28.5	49.7	5.5	83.7
1989-90	4,176	1.00	1.10	13.2	35.5	41.3	7.9	84.7
1990-91	4,198	1.03	0.04	12.6	27.8	51.9	6.6	86.3

Annex 6
Specific coal consumption in thermal power stations

Sp. coal consumption (kg/kWh)	Number of thermal power station in				
	1986-87	1987-88	1988-89	1989-90	1990-91
0.5 and less	1	1	-	-	-
0.51 - 0.55	-	-	2	2	1
0.56 - 0.60	6	6	5	7	7
0.60 - 0.65	9	7	5	8	6
0.66 - 0.70	7	7	10	8	9
0.71 - 0.75	8	7	7	7	9
0.76 - 0.80	4	11	9	8	9
More than 0.80	17	16	16	20	21

Annex 7

Statement showing improvement in PLF of thermal units where substantial R&M works have been carried out as on 1.4.1991

Name of TPS	No.	Rated capacity	Derated cap. if any (MW)	PLF before renovation: Based on rated cap. (%)	PLF before renovation: Based on derated cap. (%)	PLF after substantial renovation. Based on rated cap. (or) derated cap. wherever applicable (April-March 91) (%)
Badarpur	1	100	95	45.7	48.1	78.1
	3	100	95	57.2	60.2	66.5
	4	210	-	44.2	-	73.5
	5	210	-	37.0	-	66.8
Indraprastha (DESU)	2	62.5	-	47.9	-	57.9
	3	62.5	-	53.5	-	57.7
	5	60	-	50.3	-	73.1
Faridabad	1	60	55	28.8	31.4	78.7
	3	60	55	21.1	23.0	47.3
Bhatinda	1	110	-	48.0	-	60.8
	3	110	-	45.7	-	58.2
	4	110	-	52.6	52.6	59.9
Panki	4	110	105	43.4	45.5	53.1
Obra	2	50	40	45.7	57.1	71.6
	6	100	94	37.9	40.3	56.0
	7	100	94	30.2	41.7	52.9
	9	200	-	33.3	-	72.0
	10	200	-	31.4	-	66.7
	11	200	-	28.4	-	58.9
	12	200	-	40.2	-	74.8
	13	200	-	35.1	-	73.8
Harduaganj (B & C)	6	60	-	38.1	-	43.6
Korba-II	1	50	40	61.0	76.3	78.8
	3	50	40	62.6	78.3	80.5
	4	50	40	52.5	65.6	71.6
Korba-III	1	120	-	41.4	-	47.7
	2	120	-	56.4	-	60.5
Satpura	1	62.5	-	51.5	-	59.0
Gandhinagar	2	120	-	48.2	-	62.8
Ukai	2	120	-	38.7	-	65.5
Koradi	4	120	115	38.9	40.6	56.4
Kothagudem	1	60	-	40.0	-	58.4
	4	60	-	54.9	-	62.6
	5	110	115	27.6	28.9	44.4
	6	110	115	23.2	24.3	55.0
	7	110	-	17.3	-	50.4
	8	110	-	34.2	-	47.0
Ramagundam	1	62.5	-	70.4	-	73.2
Ennore	1	60	-	51.0	-	68.1
	2	60	-	48.1	-	63.2
	4	110	-	25.2	-	50.3
	5	110	-	26.4	-	55.0
Tuticorin	1	210	-	46.0	-	66.5
	2	210	-	47.0	-	65.1
	3	210	-	40.4	-	82.7

Annex 7 (Continued)
Statement showing improvement in PLF of thermal units where substantial R&M works have been carried out as on 1.4.1991

Name of TPS	No.	Rated capacity	Derated cap. if any (MW)	PLF before renovation: Based on rated cap. (%)	PLF before renovation: Based on derated cap. (%)	PLF after substantial renovation. Based on rated cap. (or) derated cap. wherever applicable (April-March 91) (%)
Neyveli	3	50	-	71.1	-	80.6
	6	50	-	78.3	-	83.8
	8	100	-	68.2	-	84.7
	9	100	95	66.3	69.8	79.2
Talcher	1	62.5	60	33.7	35.1	65.6
Patratu	1	50	40	32.8	41.0	51.4
	2	50	40	25.2	31.5	62.8
	6	50	90	44.3	49.2	51.0
Santaldih	4	120	-	34.1	-	56.2
DPL	3	70	-	-	-	22.2

Annex 8
Rate of return of SEBs

SEBs	1988-89	1989-90	1990-91
Andhra Pradesh	1.31	0.18	4.71
Bihar	-16.80	-20.52	-14.35
Gujarat	0.95	-11.72	-23.72
Haryana	-5.59	-5.64	-7.92
Himachel Pradesh	55.10	-3.40	2.92
Karnataka	-9.28	-14.06	3.0
Kerala	-4.51	-3.12	-13.89
Madhya Pradesh	3.94	2.91	-4.63
Maharashtra	1.41	0.48	2.56
Orissa	-4.93	3.41	3.57
Punjab	-3.57	-2.48	-2.82
Rajasthan	-4.81	-9.95	-5.89
Tamil Nadu	3.00	3.00	3.40
Uttar Pradesh	-0.02	1.43	2.92
West Bengal	-8.95	-10.27	-19.82
Assam	-26.89	-42.67	-43.18
Meghalaya	2.80	1.91	-5.56

Annex 9
Growth rate of electricity tariffs during the period 1984/85 to 1989/90

SEB/UT	Dom.*	Comm.*	Agri.*	Small Indy*	Medium Indy*	Large Indy*	All consumers
Andhra Pradesh	5.23	6.55	0.00	10.07	11.78	11.56	6.14
Assam	1.61	7.54	10.76	6.75	10.52	13.11	11.93
Bihar	0.00	2.84	0.00	6.58	6.68	7.44	5.36
Gujarat	2.10	11.44	-12.03	9.62	6.93	11.90	3.05
Harayana	5.57	7.55	5.42	22.91	17.40	19.47	5.43
Himachel Pradesh	0.30	3.97	0.00	11.27	16.94	16.83	2.96
J&K	-1.24	8.45	0.00	18.41	15.17	17.66	9.53
Karnataka	7.95	11.23	8.45	17.32	15.70	18.16	6.32
Kerala	0.00	9.46	0.00	16.86	21.04	11.06	8.88
Madhya Pradesh	1.05	3.79	0.00	10.71	8.52	13.28	4.70
Maharashtra	3.25	10.24	-7.79	12.23	13.93	10.68	7.58
Orissa	2.34	12.45	14.15	10.64	9.84	13.43	6.81
Punjab	3.02	6.96	-0.04	11.61	14.24	14.15	3.76
Rajasthan	5.46	11.35	8.45	15.72	13.89	13.63	6.45
Tamil Nadu	0.60	7.90	-7.79	10.46	13.58	13.96	4.19
Uttar Pradesh	4.92	3.36	0.00	16.44	14.94	12.82	6.51
West Bengal	0.72	8.07	0.00	2.77	0.00	12.45	5.91
Goa	5.39	6.83	8.16	7.57	8.92	12.44	n.a.
Mizoram	8.75	7.96	9.46	27.12	27.68	24.20	n.a.
Nagaland	9.34	6.21	0.00	0.95	10.03	10.03	n.a.
Sikkim	5.14	9.86	9.86	9.86	6.43	8.33	n.a.
DESU	0.00	12.72	-5.29	15.47	15.47	13.47	n.a.

* Domestic - 30 kWh/month
Commercial - 200 kWh/month
Agriculture - 5 hp, 10% load factor, i.e. 272 kWh/month
Small Indy - 5 hp, 10% load factor, i.e. 272 kWh/month
Medium Ind - 50 kW, 30% load factor, i.e 10,950 kWh/month
Large Indy - 1,000 kW, 50% load factor, i.e. 265,000 kWh/month

Annex 10
Financial working of state electricity boards 1991-92

Board	Revenue receipts	Operating expenditure	Gross operating/ surplus deficit (3-4)	Depreciation	Interest due to	
					Institutions	State govt.
Andhra Pradesh	1,652.23	1,169.00	483.23	108.35	183.03	132.70
Assam	141.62	215.25	-73.62	29.73	65.68	123.47
Bihar	595.74	782.35	-186.61	63.89	115.06	-
Gujarat	1,525.62	1,714.68	-189.06	130.75	165.31	96.26
Harayana	634.41	720.78	-86.37	45.00	71.20	83.25
Himachel Pradesh	127.00	99.85	27.15	8.81	35.67	42.44
J&K	45.07	184.86	-139.79	13.72	28.22	35.37
Karnataka	892.66	838.56	54.1	34.56	71.58	34.37
K.P.C.	383.81	196.55	187.26	26.86	52.34	71.23
Kerala	321.05	270.12	50.93	24.82	51.77	43.40
Madhya Pradesh	1,514.87	1,169.96	344.91	131.34	302.39	172.83
Maharashtra	3,379.37	2,683.64	698.73	217.54	407.39	238.34
Meghalaya	22.28	19.64	2.64	2.80	20.13	7.28
Orissa	368.70	236.36	132.34	39.92	73.90	25.22
Punjab	879.99	980.57	-100.58	91.20	92.98	276.91
Rajasthan	1,060.47	941.03	119.44	80.24	96.68	61.22
Tamil Nadu	1,731.41	1,750.02	-18.61	110.53	203.70	100.07
Uttar Pradesh	1,699.10	1,763.68	-64.58	167.24	245.86	395.82
West Bengal	757.93	727.95	29.98	33.00	122.34	61.09
Total	17,733.34	16,464.85	1,268.49	1,360.30	2,405.16	2,001.30

Annex 11
Revenue outstandings as percentage of total revenue

	For the year ended 31st March			
SEBs	*1985*	*1990*	*1991*	*1992*
Andhra Pradesh	19.70	33.40	27.63	27.87
Bihar	70.64	87.32	98.13	94.52
Gujarat	13.49	26.07	25.57	23.99
Haryana	25.28	38.34	66.87	73.74
Himachel Pradesh	28.57	33.31	51.9	56.82
Karnataka	33.21	58.34	50.32	46.12
Kerala	30.97	30.92	35.7	37.04
Madhya Pradesh	25.11	45.02	N.A.	N.A.
Maharashtra	20.73	28.77	30.85	28.83
Orissa	36.73	38.65	44.92	N.A.
Punjab	13.62	18.42	17.25	18.05
Rajasthan	29.30	17.77	16.73	15.02
Tamil Nadu	9.86	13.06	11.64	13.00
Uttar Pradesh	33.52	48.33	48.71	51.81
West Bengal	20.87	37.93	35.75	N.A.
Assam	24.63	N.A.	28.82	38.86
Meghalaya	93.24	N.A.	N.A.	N.A.

Annex 12
Indicators for manpower utilization (1991-92)

Board	*Employees per million kWh of electricity sales*	*Employees per MW*	*Employees per '000 consumers*
Andhra Pradesh	3.96	14.15	9.84
Gujarat	2.14	8.96	6.95
Haryana	5.95	25.55	16.69
Himachel Pradesh*	12.10	44.85	12.72
Karnataka	3.51	14.83	6.95
Madhya Pradesh	6.65	30.66	17.31
Maharashtra	3.63	14.16	12.02
Orissa	5.38	18.63	29.25
Punjab	5.87	22.95	19.52
Rajasthan	5.75	20.23	16.49
Tamil Nadu	5.16	20.40	10.46
Uttar Pradesh*	5.09	19.86	23.06

* Data for 1990-91
Data on employees for Assam, Bihar, Kerala, and West Bengal is not available.

The power sector in India: a macroeconomic perspective

by
Administrative Staff College of India

1. Executive summary

The power sector in India has played a very vital role in the socio-economic development of the country. Though large sections of the population are still without access to power, the fast growth of industries and urbanization could not have been possible without power. Even in agriculture, the present position of India having averted the shortages in domestic production and dependence on food imports is mostly attributable to the rapid improvement of irrigation facilities. The exploitation of sub-soil water with the use of power has played a major role in this. The total average of irrigated area under cultivation from the dawn of independence has increased from 22.6 million hectares in 1950-71 to 73.1 million hectares in 1991-92, and, of this, the area under well irrigation may be 23 million hectares. In India, out of the total number of wells, more than 9 million wells are energized.

Recognizing the importance of power to the overall development of the country, the Government of India (GOI) has taken a keen interest in the development of power with the result that this sector has shown remarkable growth during the period after independence. The fragmented power systems in urban cities have gradually been knit into state level power systems that enter state tiers or any other regional tier. The national power system, operated through a national grid, has emerged with an installed capacity of 77,000 MW in 1992-93. The length of transmission and distribution lines is over 4 million circuit km.

The power sector accounts for about one fifth of total planned expenditure. But the value added contributed by the power sector to national income is hardly 2 percent. The power sector employs nearly 1 million workers. Though the power industry is a very important sector in terms of investment and employment, its contribution to national income is more by way of its providing the energy needs of agriculture and industries.

The power industry system is operated by eighteen State Electricity Boards (SEBs), which are again formed into five Regional Boards. These SEBs have the statutory responsibility to meet the supply needs of all consumers in the area of their respective jurisdiction. As the state governments tightly controlled tariff fixation and

institution agricultural tariff to be far below operating cost, all SEBs have become financially very weak and incapable of raising the funds needed to set-up the power projects required to meet the increasing power demand.

The GOI has tried to augment power supply by setting up power generation companies under the central government that sell power in a pre determined ratio to the SEBs. National Thermal Power Corporation (NTPC), National Hydro Power Corporation (NHPC), and later Nuclear Power Corporation (NPC) were the result. But these, by themselves, could not bridge the supply-demand gap. The quality and reliability of power have deteriorated. Demand has been running far ahead of supply in all states in India. Most of the areas are facing a situation of wide fluctuations in supply voltage and frequency, frequent interruptions and low voltage conditions. Of the eighteen SEBs, except one state (Andhra Pradesh) and marginally two more (Madhya Pradesh and Maharashtra), all other SEBs are in the red. Due to the resource crunch, the foreseeable situation is an increasing gap between demand and supply. The accumulated losses of the public sector power industry is Rs. 21,891 crores as of March 1992.

None of the Boards project an image of commerciality. Most of the projects are implemented with long delays. The operation and maintenance costs are rising out of control, the financial management in terms of tariff fixation over receivables are poor, and the establishment expenditure has been rising. The unsatisfactory performance of SEBs has created problems for central sector organizations like NTPC, NHPC, Bharat Heavy Electricals Limited (BHEL), because of their inability to meet their commercial obligations to these organizations.

It is not only in financial terms, but also in terms of operational efficiency as seen from different parameters, that the power industry exhibits inefficiency; but more disconcerting is the fact that these inefficiencies have been increasing over time. Capacity utilization, measured in terms of plant load factor, would increase slowly over the years, but has never reached the target of 58 percent, set in the Rajadhaksya Committee. Transmission and distribution (T&D) losses have slowly deteriorated from around 15 percent in the 1950s to nearly 23 percent currently. Labor productivity, measured in terms of the number of employees per million capacity sold or per thousand consumers sold, is decreasing, but is still very low compared to other countries. These, combined with the lack of adequate investments to modernize, have made the power industry sick.

As of today, most of the SEBs will come under the definition of "sick industries" where their accumulated losses exceed their net worth/assets.

SEBs, state governments, and the GOI were aware of the need for reforms. There have been several efforts. The GOI tried first, to supplement the finances of the state governments by providing them with special advances for implementing power projects. Since this did not meet their needs, the GOI set up central power generating plants by organizing corporations like NTPC, NHPC, and NPC. Then the Power Finance Corporation (PFC) was set up to financially assist the SEBs to undertake system improvement projects. Though PFC was to lend on a commercial basis, the distributional pressures have upset the expectations from PFC. Several reports were also commissioned by the GOI to look into the workings of the power sector. Suggestions have been made to improve technical performance on the demand and supply sides, and also on financial aspects. Most of the recommendations could not be implemented. In fact, on several parameters, the situation worsened.

The main problem of the SEBs arose on account of the state governments' competing with each other to reduce the tariff on agriculture and thereby sapping the financial resources. When the Eighth Plan demand indicated an additional capacity requirement of over 30,000 MW on an investment of Rs. 126,000 crores, the GOI, in a hurry, decided to review the basic policy of the power sector and allow private sector participation in power generation. But, this was a reluctant privatization; as of now, the private power generators can only sell power to public utilities. Against this background, we need to examine whether getting this additional capacity installed by inviting the private sector to participate in power generation is the only option.

It is clear that, with the delays in public sector projects and the unexpected delays in settling contracts for private power generation, it would not be possible to achieve a target of 30,538 MW by 1997. But the supply system could be used more effectively to significantly reduce the power supply-demand gap. In the forecasts, the required capacity to meet demand of 0.58 MW is assumed to be only 1 MW. This can be improved by better maintenance of power plants. If the load curves are flattened by proper

demand management, it would be possible to reduce the anticipated peak demand for the same energy requirement. A 5 percent improvement in the ratio of peak demand/energy would reduce peak demand by 3,500 MW in the terminal year of the Eighth Plan. The peak capability of the supply systems has been assumed to be low because of past experience. Peaking capability of the thermal systems is assumed at 58 percent due to forced outages of 23 percent. If it is reduced by 10 percent, the requirement of the total system will come down by 8,100 MW in 1996-97.

Despite differences or exact approximations in anticipated demand, the issue of additional generation remains preeminent. The point of inquiry is whether the SEBs are in a financial position to do so, or if it is necessary to invite private parties, and whether the invitations of the private agencies above will reform the power industry. A holistic examination of the issues in the power sector suggests that the policy change to invite private agencies to set up power generation is inadequate to remedy the problem.

Unless the SEBs are structurally changed and made to work on commercial lines, they will not be able to pay for the power supplied by private agencies and, from then on, private agencies would not come forward. As long as SEBs are funded exclusively by or through state governments, they cannot be commercially run. State governments could not encourage the SEBs to be commercial. When power was extended to rural areas, the important clients were the farmers who use power for pumping water. The state governments had the dilemma that water supplied to farmers from surface irrigation sources, built, owned and operated by the state governments, is at very low rates which do not even cover the costs of maintenance of the state-owned irrigation sources, let alone pay for the amortization of investment. State governments, therefore, are and will be forced by farmers' lobbies to make power tariffs to farmers cheap, so that the cost of water to them could be on par with water supply from surface irrigation sources. When the costs of power generation went up over the years, state governments intervened to prevent the adoption of long-term marginal costing by the SEBs and to provide power at highly subsidized rates to farmers that was even far below the average cost of power generation.

Immediate reforms to affect structure and institutional changes are required. The first reform is to convert the SEBs into public limited companies. In order to distance the state governments from the SEBs, the general public, the stake-holders in the power industry, should be allowed to contribute to the equity and be allowed an appropriate share in the strategic decision making of the new power companies. The introduction of private power generation companies should be used to create and nurture competition in the power supply system. This is possible by deregulating the power supply system to large consumers who take their supply at high voltage. Though difficult, this is possible and will have to be programmed and pursued. The package of reforms to make the power industry commercial and competitive is discussed in a companion paper (``*Commercialization of the Indian Power Sector*'' by the Administrative Staff College of India).

2. An overview of the power sector

2.1 Trends in installed capacity

The total installed power generating capacity in public utilities during the plan periods has increased from 1,712 MW in 1950 to 69,796 MW in 1992-93, a forty-fold increase in 42 years, increasing at a compound growth rate of 9.2 percent per annum. The growth of hydroelectric power capacity was 8.8 percent per year during 1950-51 to 1992-93. The growth rate was 11.85 percent in the 1950s and 13.8 percent in the 1960s. These growth rates gradually reduced to 6.65 percent in the 1970s and 4.2 percent in the 1980s (Table 1).

From the table it can be seen whereas the installed capacity growth of thermal power ranged between 8 percent and 9 percent per annum except in the 1970s where the growth rate was about 12 percent per year. Over the period, the annual installed capacity has grown at the rate of 9.3 percent per annum. In the recent past; i.e., during the Eighth Five Year Plan (FYP) (1985-86 to 1989-90) about 21,401 MW of additional power-generating capacity was added against a target of 22,245 MW, achieving 96 percent of the target. Since then, only 6,160 MW of additional power generating capacity was added until March 1993. On the whole, a total of 41,348 MW of additional generating capacity was created since 1980-81.

Table 1
Growth of installed power generating capacity (figures in percentages)

During	*Hydro*	*Thermal*	*Nuclear*	*Total*
1950-51 to 1959-60	11.85	8.20	—	9.50
1960-61 to 1969-70	13.80	11.90	—	13.10
1970-71 to 1979-80	6.65	8.50	4.80	6.85
1980-81 to 1992-93	4.20	8.90	8.60	7.25
1950-51 to 1992-93	8.80	9.30	6.65	9.20

Source: Central Electricity Authority, GOI.

The growth in hydropower generation was less compared to thermal power generation throughout the period under consideration. The share of hydro generation in the total generating capacity of the country has declined from 34 percent at the end of the Sixth FYP to 29 percent at the end of the Seventh FYP. This is likely to decline in the next decade. The hydropower projects with storage facilities provide peak demand to power system. The NTPC and NHPC contribute to play an important role in supplementing the efforts of SEBs. The central share in generation capacity has increased from 16 percent at the end of the Sixth FYP to 26.1 percent at the end of 1991-92. The major contribution to this came from NTPC.

In the nuclear front, the country has adequate quantities of uranium to meet the life-time requirements of the first stage nuclear power development program of 10,000 MW. In addition, there are large deposits of raw materials used in nuclear power generation, that are estimated to generate 900,000 billion units of electricity.

2.2 *Trends in power generation*

Power generation in hydro and thermal power stations increased at the rate of 12.0-13.4 percent per annum in the 1950s and 1960s, and it slowed down in the 1970s and 1980s (Table 2).

The overall power generation by public utilities increased at the rate of 9 percent per annum in the 1980s. During 1991-92, power generation increased by 8.5 percent over 1990-91. Although, generating capacity of 41,348 MW was added during 1980-81 to 1992-93, the growth in generation was not satisfactory due to the under-utilization of power plants and drought conditions.

Plant load factor (PLF) is an important indicator of the utilization of thermal and hydropower plants. As part of every FYP, the demand for peak load and energy is forecasted. From these, the required additional installed capacity is calculated using the PLF achieved in the previous period, adjusted for possible improvements in the forecast for thermal plants. The hydro plant energy and peak load supply is forecasted from their design characteristics. The overall PLF of thermal power plants showed a marked improvement over the years. The PLF which was 47.9 percent during 1983-84 has increased to 56.5 percent in 1989-90. It fell to 53.8 percent in 1990-91 and again increased to 57 percent in 1992-93, as shown in Table 3. The thermal power plants in the central and private sectors, though small in capacity, registered a

Table 2
Growth of electric power generation in India (figures in percentages)

During	*Hydro*	*Thermal*	*Nuclear*	*Total*	*Non-utilities*
1950-51 to 1959-60	12.06	13.35	—	12.70	—
1960-61 to 1969-70	12.75	13.10	—	12.95	4.05
1970-71 to 1979-80	6.80	8.00	2.00	7.25	4.80
1980-81 to 1992-93	3.45	11.42	12.82	8.67	11.00
1950-51 to 1992-93	8.22	11.22	7.30*	10.20	7.20**

* Growth rate refers to the period during 1969-70 to 1992-93.
** Growth rate refers to the period during 1960-61 to 1992-93.

Source: Central Electricity Authority, GOI.

Table 3
Plant load factor (figures in percentages)

	Central sector	*State electricity boards*	*Private sector*	*Overall*
1983-84	54.8	44.1	64.1	47.9
1984-85	55.4	44.9	63.0	50.1
1985-86	61.9	46.8	57.5	52.4
1986-87	64.9	48.6	61.1	53.2
1987-88	63.3	53.0	67.6	56.5
1988-89	62.6	49.6	63.2	55.0
1989-90	62.2	54.6	69.5	56.5
1990-91	58.1	50.0	58.4	53.8
1991-92	64.7	51.1	56.7	55.3
1992-93	59.5	48.3	60.1	57.0

Source: Current Energy Science in India, Centre for Monitoring Indian Economy, May 1993.

higher PLF compared to State Electricity Boards during the past decade.

The utilization of SEB power plants was not very satisfactory. The PLF of 15 SEBs averaged 51.1 percent in 1991-92 and 48.3 percent during the first nine months of 1992-93. These were 7 percent below the Rajadhyaksha Committee recommendation of 58 percent PLF. The performance of individual SEBs showed very wide variations in the PLF. The majority of states had a PLF less than 50 percent. States like Rajasthan, Tamil Nadu and Andhra Pradesh had a PLF more than 60 percent over a period of time on the one hand, and states like Haryana, Orissa, Bihar and Assam had a PLF less than 45 percent on the other. In a few states like Orissa, Bihar and Assam, the average PLF was as low as 35 percent. It was estimated that a one percentage point improvement in the PLF would be equal to an additional installed capacity of 500 MW. If the SEBs improve their PLF, the additional installed capacity required for Eighth and Ninth FYPs could be trimmed substantially.

2.3 *Power consumption trends*

The power utilization from 1960-61 to 1991-92 is given in Table 4. Total energy sold has gone up by 15 times from 13,841 million kWh in 1960-61 to 207,645 million kWh in 1991-92, increasing at the compound rate of 9.1 percent per annum.

From the table it can be seen that the share of energy consumed in industry has gradually

Table 4
Power utilization 1960-61 to 1991-92

	Total energy sold	*Share of*					
		Industry	*Agriculture*	*Domestic*	*Commercial*	*Railways/ tramways*	*Others*
1960-61	13,841	69.4	6.0	10.7	6.1	3.3	4.5
1965-66	26,735	70.6	7.1	8.8	6.2	4.0	3.3
1970-71	43,724	67.6	10.2	8.8	5.9	3.2	4.3
1975-76	60,246	62.4	14.5	9.7	5.8	3.1	4.6
1980-81	82,367	58.4	17.6	11.2	5.7	2.7	4.4
1985-86	122,999	54.5	19.1	14.0	5.9	2.5	4.0
1986-87	135,952	51.7	21.7	14.2	5.7	2.4	4.3
1987-88	146,205	47.5	24.2	15.2	6.1	2.5	4.5
1988-89	160,196	47.1	24.3	15.5	6.2	2.3	4.6
1989-90	174,818	46.0	25.1	16.9	5.4	2.3	4.3
1990-91	190,357	44.9	26.0	16.5	6.1	2.2	4.3
1991-92	207,645	42.0	28.2	17.3	5.8	2.4	4.5

Source: Current Energy Scene in India, Centre for Monitoring Indian Economy, May 1993.

come down to 42 percent in 1991-92 from 69.4 percent in 1960-61. The share of agriculture has increased to 28.2 percent from 6 percent during the same period. This steep increase of consumption in agriculture is due to the encouragement given to this sector by supplying electric power to farmers, to lift water for irrigation, on a priority basis.

The low or almost non-existent electricity charges for agriculture encouraged energizing of pump-sets rapidly. The steep increase in oil prices persuaded farmers to opt for electric pumpsets rather than diesel units. The share of domestic consumption has also increased during this period due to the increase in the number of households and the income increase in the upper decile of the population. The rural electrification program of the GOI has led to increases in consumption in the domestic and agricultural fronts. The consumption share of commercial and traction has marginally come down over a period of time.

The rate of growth of power consumption averaged 9.1 percent per annum during 1960-61 to 1991-92, whereas generation was 9.6 percent. During the 1980s, the rate of growth in consumption was 8.9 percent. Demand for power, with the expansion of industry and agriculture, is expected to outstrip the supply of electricity. This has resulted in continued shortages of power in different parts of the country, forcing the power supply authorities to impose restrictions both on supply and demand. The supply of energy was 8.5 percent short of demand at the all-India level, and peak shortage was about 19 percent in 1992-93 (see Table 5).

The Planning Commission and Central Electricity Authority estimates show that the gap between the requirements and supply of power will come down by the end of the Eighth Plan Period. But past experience makes us hesitant to readily accept this viewpoint. Later in Part 3, we project alternative scenarios of power demand.

2.4 *Transmission and distribution losses*

T&D losses in the power system continued to remain high over a period of time. The SEBs and NTPC (until 1992) are responsible for T&D of electric power. The all-India T&D losses increased from 17.6 percent in 1970-71 to 20.6 percent of generation by 1980-81. By 1991-92, these losses increased to 22.9 percent.

Energy losses have increased from 22,790 million units in 1980-81 to 65,657 million units in 1991-92, growing steadily at the rate of 10.1 percent per year. There are no scientific studies that estimate transmission losses and distribution losses separately. But it is reported that transmission losses are in the range of 5-7 percent and the remaining are distribution losses. These losses remained significantly higher than the international average of 10 percent. However, in the absence of satisfactory metering arrangements in the case of agricultural consumers, the level of losses indicated by the states could, at best, be an estimate of the energy not accounted for in the system. The high T&D losses could be largely attributed to the low investments made on T&D facilities in different states, and the extensive lower-voltage distribution network in rural and urban areas.

Table 5
Demand and supply of electrical power in India (billion units)

	Demand	*Supply*	*Deficit %*
1980-81	120.1	104.9	-12.6
1981-82	129.2	115.3	-10.8
1982-83	136.8	124.2	-9.2
1983-84	145.3	129.7	-10.7
1984-85	155.4	145.0	-6.7
1985-86	170.7	157.3	-7.9
1986-87	192.4	174.3	-9.4
1987-88	211.0	188.0	-10.9
1988-89	223.2	205.9	-7.7
1989-90	247.8	228.2	-7.9
1990-91	267.6	246.6	-7.9
1991-92	289.0	266.4	-7.8
1992-93	278.0	254.6	-8.4

Source: Current Energy Scene in India, Centre for Monitoring Indian Economy, May 1993.

Table 6
Transmission and distribution losses (as percent of electricity generated)

State	*1980-81*	*1985-86*	*1986-87*	*1987-88*	*1988-89*	*1989-90*	*1990-91*	*1991-92*	*Average 1985-86 to 1991-92*
Haryana	22.6	19.8	20.6	25.4	26.6	29.2	27.6	22.9	24.6
Uttar Pradesh	15.6	20.5	20.0	26.8	27.4	26.1	26.1	26.0	24.7
Rajasthan	26.6	26.5	23.9	21.0	25.3	24.4	24.9	21.0	23.9
Orissa	19.2	23.0	22.0	23.3	27.5	24.0	23.0	23.0	23.7
Kerala	14.9	24.6	27.5	21.3	25.2	22.5	21.0	22.0	23.4
Gujarat	19.8	25.5	24.0	23.5	19.6	22.1	22.1	21.0	22.5
West Bengal	13.7	23.1	23.2	21.2	23.2	22.7	21.9	20.0	22.2
Bihar	22.1	22.5	22.1	21.7	24.0	21.5	21.0	21.5	22.0
Assam	19.3	20.0	21.0	20.2	25.0	21.6	21.0	20.5	21.3
Andhra Pradesh	22.6	19.2	18.5	20.2	19.4	20.2	19.6	20.0	19.6
Karnataka	24.6	22.5	22.2	21.0	21.3	20.5	19.6	19.3	20.9
Madhya Pradesh	22.3	18.9	20.8	20.5	22.1	19.5	18.8	18.3	19.8
Punjab	19.6	18.8	17.0	18.4	18.3	18.1	19.0	19.0	18.4
Tamil Nadu	19.1	18.7	18.7	18.6	17.7	18.5	18.4	18.4	18.4
Maharashtra	16.2	14.5	14.5	14.3	15.8	17.6	15.5	15.0	15.3
Jammu & Kashmir	48.1	35.9	33.5	41.8	41.5	49.5	46.2	50.0	42.6
All India	20.6	21.7	21.5	22.1	22.3	22.9	22.9	22.9	22.3

These factors have also contributed to the poor quality of electricity supply in many parts of the country.

From Table 6 it can be seen that the T&D losses estimated at 26.0 percent in Uttar Pradesh during 1991-92 was highest among major states, followed by Orissa (23.0 percent) and Haryana (22.9 percent). The losses in Haryana dropped from 29.2 percent in 1989-90 while losses in Uttar Pradesh increased from 15.6 percent in 1980-81 to 26.0 percent in 1991-92. Six states namely Haryana, Uttar Pradesh, Rajasthan, Orissa, Kerala, and Gujarat accounted for higher losses compared to the national average of 22.3 percent. Jammu and Kashmir lost 50 percent of the power generated because of the problems prevailing in that state. The losses were least in Maharashtra, which was estimated at 15 percent of generation.

From the table, it can also be observed that there has been a progressive increase in T&D losses in some SEBs. In some SEBs, the losses have gone up by more than 2 percent between successive years. Some states have registered more than 27.5 percent in T&D losses. Reduction in T&D losses will improve the overall system performance with less cost and in a faster time frame. The returns on these investments are quite substantial since there are no recurring costs involved in making power available to the system. It was estimated that a 1 percent reduction in T&D losses on a national basis would additionally supply 1,800 million kWh to the system. This would increase an additional revenue of Rs. 1,280 million at 1987-88 tariff levels. This leads to avoid an investment of 530 MW at an estimated cost of Rs. 7,950 million. This is another important aspect which the SEBs should concentrate to increase the system's overall performance.[1]

2.5 *Investments and returns*

Investment in the power sector alone, on average, constitutes about 17.7 percent of the total investment of FYPs. Investment has gone up from Rs. 67,670 million during the Third FYP to Rs. 342,730 million during the Seventh Plan in 1984-85 prices. It is expected to be Rs. 459,990 million, during the Eighth FYP (795,890 million in 1991-92 prices), which is nearly a seven-fold increase over the Third Plan. With this huge investment, substantial generation capacity has already been added in the country. The returns on these investments are not at all satisfactory,

[1] Government of India, Ministry of Energy, Report of the Working Group for suggesting steps for strengthening the finances of SEBs, May 1989, New Delhi.

Table 7
Yearly profit and losses of SEBs after taking into account re-subsidy as provided in the account (Rs. crores)

	1975	*1980*	*1985*	*1986*	*1987*	*1988*	*1989*	*1990*
Andhra Pradesh	-0.3	6.0	49.7	14.4	40.8	37.9	39.8	57.9
Bihar	-12.5	-17.0	-9.7	-121.1	4.2	-110.5	-48.4	-8.3
Gujarat	-4.8	-8.7	36.1	-1.7	13.4	34.9	-171.5	239.9
Haryana	-9.3	-11.0	-74.0	-61.5	-70.2	-163.6	-25.1	-20.1
Himachal Pradesh	-2.8	-5.8	-22.4	-8.3	-11.3	-16.6	-14.9	-13.4
Karnataka	-0.9	8.5	10.8	20.7	-60.0	-86.1	37.1	38.0
Kerala	-7.5	11.4	9.7	4.8	7.6	6.8	-37.1	-23.7
Madhya Pradesh	2.3	6.5	-18.2	21.1	126.8	64.4	80.0	82.6
Maharashtra	13.7	-27.5	-33.2	-26.3	64.5	73.1	54.2	37.6
Orissa	-6.2	-12.3	-12.5	-10.2	2.5	-31.6	-3.0	27.1
Punjab	-18.8	9.7	-6.6	-6.4	-19.8	-1.3	-38.9	-538.3
Rajasthan	-3.3	16.1	-73.5	-47.8	-13.7	-77.7	-29.5	-117.3
Tamil Nadu	8.1	8.9	8.7	27.9	96.8	33.1	136.7	32.6
Uttar Pradesh	-54.2	-70.5	-42.0	-152.3	109.7	129.7	-231.8	204.4
West Bengal	-2.7	-1.8	-35.2	-72.0	-18.3	6.6	-25.4	-8.8
Assam	12.3	-11.7	-43.4	-92.6	-51.3	-17.2	-119.9	-87.1
Meghalaya	-12.2	-1.6	-1.9	-2.4	-0.5	2.4	1.5	10.8
Losses	-135.0	-167.9	-372.5	-602.6	-245.1	-504.5	-745.5	-126.3
Surplus	37.3	61.7	115.0	88.9	466.3	388.9	349.3	276.8
Net	-97.7	-106.2	-257.5	-513.7	221.2	-115.6	-396.2	-984.5

Source: Report of the Working Group for suggesting steps for strengthening the Finances of the State Electricity Boards, GOI, Central Electricity Authority, New Delhi.

Table 8
Unit cost of thermal generation of SEBs (Ps/kWh)

Year	*Generation cost*	*Coal cost*	*Oil cost*	*O&M cost*	*Establishment cost*
1988-89	37.9	33.5	3.8	4.9	16.5
1989-90	43.4	39.7	3.5	5.2	17.2
1990-91	46.2	41.2	4.2	5.5	18.7
1991-92	57.2	45.6	4.8	5.7	19.1
1992-93	53.7	51.1	5.1	5.8	19.2

since most of the SEBs have been incurring huge losses for some time.[2] The SEBs that are generating surpluses include Andhra Pradesh, Madhya Pradesh, Maharashtra, and Tamil Nadu (Table 7). It was only in 1987 that the SEBs, put together, generated a surplus, of Rs. 2,212 million. Investment in electric supply will remain a problem when SEBs are unable to generate a surplus and have balance sheets which will not enthuse commercial lenders to assist them.

The reasons for the huge losses of SEBs are many. They include low generating levels of power plants, high T&D losses, pilferage, non-payment of rural electrification subsidies to compensate the Boards for the loss of revenue sustained in supplying power at uneconomic tariffs, and cost over-runs in completing the projects. In addition, the cost of inputs has also gone up sharply. The average unit cost of thermal generation of SEBs is given in Table 8 above.

In addition to these rising costs, the tariffs prescribed for agriculture and domestic supply have also contributed to the losses of SEBs. The tariff rates for agriculture ranged between 2.1 paise per kWh in Tamil Nadu to 31.24 paise per kWh in Rajasthan in 1992-93. In a few states, the rates charged for agriculture are decreasing. On average, the rate of sale of electricity for all categories of consumption was 49 paise per unit

[2] Government of India, Report of the Group on Power, Eighth Plan Power Program, September 1991, New Dehli.

Table 9
Estimated losses on account of agricultural and domestic consumption in 1992-93

State	Avg. cost of electricity (Ps/kWh)	Estimated loss on	
		Agricultural (Rs. crores)	Domestic (Rs. crores)
Andhra Pradesh	102.2	641.3	61.9
Assam	211.4	4.5	28.9
Bihar	168.7	278.9	37.7
Gujarat	128.7	734.2	109.6
Haryana	129.5	339.9	57.7
Himachal Pradesh	3.3	22.1	
Jammu & Kashmir	176.6	24.1	—
Karnataka	97.1	432.4	22.4
Kerala	75.4	10.2	10.3
Madhya Pradesh	132.4	324.2	391.1
Maharashtra	122.5	788.2	140.4
Orissa	89.7	22.7	31.0
Punjab	114.3	669.9	52.5
Rajasthan	128.0	314.3	72.1
Tamil Nadu	134.1	483.4	203.4
Uttar Pradesh	126.2	754.8	249.2
West Bengal	152.4	63.8	71.6
Total		5,889.4	1,565.2

Table 10
Targets and achievements in the power sector (MW additions to installed capacity)

Plan	Target	Achievement	Percentage achievement (percent)
Second Plan	3,500	2,250	64.0
Third Plan	7,040	4,520	64.0
Annual Plans (66-67 to 68-69)	5,430	4,120	76.0
Fourth Plan	9,264	4,579	49.4
Fifth Plan	16,548	10,017	60.5
Sixth Plan	28,448	14,226	50.0
Seventh Plan	22,245	21,401	96.0
Eighth Plan	30,538	—	—

Source: Planning Commission, Various Five Year Plan Documents.

in Jammu and Kashmir which was the lowest and 124.84 paise per unit in Maharashtra which was the highest in the year 1992-93. Due to the low tariffs for agricultural and domestic consumption, the losses incurred by SEBs are very substantial as can be seen from Table 9.

All these factors adversely affected the efficient functioning of SEBs. As a result, they were unable to meet their commercial obligations to organizations like NTPC, NHPC, Coal India Limited (CIL), and BHEL, etc. The non payment of dues by the Boards has created problems for various central sector organizations in their day-to-day operations. Two major factors; i.e., increasing the PLF of thermal power plants and reducing the T&D losses will improve the performance of the SEBs to a substantial extent, with least cost.

The targets and achievements of the power sector, in terms of installed capacity, during the plan periods is given in Table 10 above.

The achievement in installed capacity was higher in the early Plan Periods (Second, Third, and Annual Plans) which ranged between 64 percent and 76 percent. During the Fourth and Sixth Plans, the installed capacity achieved was 50 percent of the target. Only in the Seventh Plan was the achievement very high, at

Table 11
Potential for reducing peak demand and installed capacity requirements

	Business as usual			*With efficiency improvement*		*Savings*	
	Energy demand (Bn units)	*Peak demand (MW)*	*Installed capacity (MW)*	*Peak demand (MW)*	*Installed capacity (MW)*	*Peak demand (MW)*	*Installed capacity (MW)*
1992-1993	308.16	54,634	74,976	49,853	70,426	4,781	358
1993-1994	333.41	59,122	80,628	53,934	75,774	5,188	340
1994-1995	359.61	63,760	87,246	58,164	81,993	5,596	399
1995-1996	386.97	68,541	94,431	62,574	88,746	5,967	433
1996-1997	416.27	73,656	105,670	67,296	99,308	6,360	677
1997-1998	447.64	79,122	112,981	72,347	103,470	6,775	616
1998-1999	481.17	84,960	121,465	77,746	111,237	7,214	715
1999-2000	517.00	91,160	130,136	83,515	119,178	7,675	730
2000-2001	536.17	97,746	139,966	86,364	128,180	11,382	828
2001-2002	594.52	104,641	152,402	95,989	139,569	8,652	1,047

96 percent of the target. Except in the Seventh FYP, the performance in installed capacity was less than what was targeted in the Plans.

During the planning period, it was recognized that T&D losses were fairly high, PLF was much below the anticipated rates, the pricing of electricity was not proper, problems in T&D of electricity existed, and the quality of power supply was not satisfactory. Power projects were taking a much longer time to complete, leading to cost and time over-runs. On average, the cost over-run was 68.6 percent and time over-run was 4-128 months of original schedules. These factors led to the unsatisfactory performance of electricity boards, both on the financial side, and the generation and distribution side.

3. Power sector: macro relationship

The relationship between the power sector and the rest of the economy are more clearly highlighted when we examine crucial macro-relationships between the two. In this section, we have focused on six relationships as a basis for estimating the costs to the economy.

3.1 Demand for power

Exercises for estimating demand for power are always interesting and tend to vary depending on the methodology adopted. Choice of data and estimation problems also contribute to these differences. The net result is that macro-projections, even within official estimates, tend to lend an element of uncertainty. In the current scenario, when the economy is going from a relatively planned and controlled economy to an open economy, power projections do remain as approximations. Nonetheless, macro-relationships depend on projections regarding the demand for power. We present here two estimates of the demand for power. They are:

- The official demand projections based on the Fourteenth Electric Power Survey of India,[3] and
- Elasticity of electricity consumption to gross domestic product (GDP).

The estimates of official demand projections, which is considered as "Business as Usual," (BAU) is modified to take into account projections based on the Western Region pattern as the "efficient case."

3.2 Official projections

Energy demand, peak demand, and installed capacity, that have been estimated by the working group on power, is given in Table 11 as

[3] Central Electricity Authority, Government of India, Fourteenth Electric Power Survey of India, March 1991, New Delhi.

"Business as Usual" scenario. The Western Region of the country is the most efficient in meeting the energy and peak demands compared to other regions of the country. This has been taken as the efficient scenario. Based on these two scenarios, it is possible to reduce the peak demand substantially as given in column 6 of the Table, and still meet the energy requirements during the Eighth and Ninth FYP periods. It is estimated that 6,143 MW of investment on capacity could be reduced if adopting the performance of Western Region is applied to the whole country.

3.3 *GDP growth and electricity demand*

Elasticity indicates the demand for power. It is defined as the rate of change in consumption for a unit change in income (indicates change in demand for change in income). The consumption elasticity for power over the period from 1960-61 to 1989-90 was 2.23. This elasticity was gradually decreasing during the 1970s and 1980s. The consumption elasticity in the 1980s was 1.83. Similar trends can be observed for the industrial and commercial sectors as well, as shown in Table 12 below.

Table 12
Elasticity of consumption

Period	*Total consumption elasticity*	*Industry and commercial demand*
1960-61 to 69-70	2.49	2.42
1970-71 to 79-80	2.11	1.51
1980-81 to 89-90	1.62	1.18
1960-61 to 89-90	2.23	1.43

Based on these estimates, with the 5.6 percent growth in GDP during the Seventh FYP, the growth of electricity consumption works out to 9 percent. In the Eighth FYP, growth of the power sector is expected to be 9 percent. The Planning Commission and Central Electricity Authority have estimated that the gap between the requirements and supply of power will come down by the end of the Eighth Plan.

The relationships between GDP growth and the value added due to electricity, electricity consumption, and the electricity generated are expressed in the following equations given below.

$$Y = \underset{(25.66)}{538.58} + 36.11\ VAE, \quad r^2 = 0.988$$

$$Y = \underset{(10.63)}{636.74} + 7.39\ CE, \quad r^2 = 0.966$$

$$Y = \underset{(29.35)}{638.84} + 5.04\ GE, \quad r^2 = 0.991$$

Where:

Y is Gross Domestic Product in billions of rupees in 1980-81 prices.

VAE is Gross value added due to electricity in rupees crores at 1980-81 prices

CE is consumption of electricity in billion units

3.4 *Investment in the power sector*

Of the total public sector outlay, the energy sector constituted about 29 percent in the Sixth FYP and 28.6 percent in the Seventh Plan. Investment in the power sector alone, on average, constitutes about 17.7 percent of total public sector investment during the FYPs. The increased outlays in planned investment are discerned from the Fifth FYP onwards, when the central generating power states were commissioned.

During the 1980s, investment in the electricity sector increased at the rate of 6.5 percent per year in real prices, as against investment in public sector of 6.0 percent and 6.8 percent for the economy as a whole. Investment went up from Rs. 6,767 crores during the Third FYP to Rs. 34,273 crores during the Seventh FYP at 1984-85 prices (Table 13). It is expected that investment will reach Rs. 45,999 crores during the Eighth FYP, which is nearly a seven-fold increase over the Third Plan. The share of power sector investment to public sector investment during the Sixth and Seventh FYPs was, on average,

Table 13
Plan outlay for power sector (current prices)

Plan	*Outlay (Rs. crores)*	*Percent of total*
Third Plan	1,252.3	14.6
Annual Plans	1,212.5	18.3
Fourth Plan	2,931.7	18.6
Fifth Plan	7,399.5	18.8
Sixth Plan	18,897.0	18.2
Seventh Plan	34,273.5	19.0
Eighth Plan	45,999.0	18.3

23.7 percent, while its share to total investment in the country was 10.4 percent during the same period. The share of power investment to public sector investment has come down from 23.6 percent in 1980-81 to 19.9 percent in 1984-85. Thereafter, this share has gone up significantly. The share of power investment to total investment has increased marginally by 1 percent during the 1980s. The investment in electricity, the public sector, and the economy is presented in Table 14.

3.5 *Pattern of financing*

Investment in SEBs consists of state government loans, borrowings from institutional sources, market borrowings and internal resources. During the Seventh FYP period, Electricity Boards have invested about Rs. 20,967 crores, of which state government loans were in the order of Rs. 11,851.5 crores or 56.5 percent, market borrowings were 14.1 percent, and borrowings from institutional sources were 39.9 percent as given in Table 15. Interestingly, most of the SEBs could not raise internal resources because of their poor performance in operations. The share of state government loans and borrowings from institutional sources to total borrowings are increasing, whereas market borrowings marginally decreased during this period. Internal resources of the SEBs were positive during the first two years of the Seventh FYP, thereafter showing a negative share, which increased from -8.6 percent during 1988-89 to -19.5 percent during 1990-91. On the whole, the SEBs were unable to raise their own resources through internal improvements.

Table 14
Investment in electricity, the public sector and the economy

	Gross capital formulation in			*Share of elect. investment in*	
	Power sector	*Public sector*	*Country*	*Public sector*	*Country*
	1980-81 prices (Rs. crores)			*in %*	
1980-81	2,780	11,767	28,453	23.6	9.8
1981-82	3,358	15,178	35,888	22.1	9.3
1982-83	3,568	16,635	39,982	21.4	8.9
1983-84	3,453	15,502	32,240	22.3	10.7
1984-85	3,500	17,588	33,249	19.9	10.5
1985-86	3,984	18,216	39,451	21.9	10.1
1986-87	5,009	19,584	39,925	25.6	12.5
1987-88	5,010	17,958	42,089	27.9	11.9
1988-89	4,972	19,346	47,440	25.7	10.5
1989-90	5,329	20,895	49,194	25.5	10.8
1990-91	5,216	21,091	54,895	24.7	9.5
Average				23.7	10.4

Source: National Accounts Statistics.

Table 15
Pattern of financing investment in state electricity boards (as percentages)

During Seventh Plan	*(Rs. crores) 1986-1991*	*1986-87*	*1987-88*	*1988-89*	*1989-90*	*1990-91*
Market borrowing	2,947.1 (14.1)	4,687.0 (14.7)	(12.9)	(12.3)	(16.9)	(8.4)
Institutional sources	8,374.3 (39.9)	2,435.3 (29.4)	(27.6)	(34.6)	(35.3)	(43.4)
Internal resources	-2,206 (-10.5)	-1,092.4 (0.5)	(2.4)	(-8.6)	(-25.4)	(-19.5)
State govt. loans	11,851.5 (56.5)	3,801.5 (55.5)	(57.1)	(61.7)	(73.3)	(67.7)
Total	20,966.9 (100.0)	5,613.1 (100.0)	(100.0)	(100.0)	(100.0)	(100.0)

Source: Annual Report on the working of state electricity boards and electricity departments, August 1992, Planning Commission, New Delhi.

Table 16
Cost per kWh delivered praise/kWh sold at 1991-92 prices

Year	Average cost of supply	Average realization including agriculture	Gap	Average realization excluding agriculture	Gap
1980-84	90.57	69.82	20.75	76.22	14.35
1984-85	113.21	85.93	27.28	99.45	13.76
1985-86	116.59	93.38	23.21	110.12	6.47
1986-87	124.07	102.44	21.63	124.50	-0.51
1987-88	132.26	103.51	28.75	131.34	0.92
1988-89	132.63	102.39	30.24	130.83	1.80
1989-90	131.80	119.72	32.08	129.03	2.77
1990-91	132.36	89.38	42.98	118.14	14.22
1991-92	119.20	96.90	22.30	122.30	-3.10
Average	125.26	96.71	28.55	120.72	4.54

3.6 Cost of power

The average cost of energy supplied to consumers, per kWh, is presented in Table 16. The supply cost of energy was calculated at 1991-92 prices and, accordingly, adjustments were made for the period up to 1980-81. Average cost has gradually increased during the 1980s, whereas it has come down during 1991-92. The average cost of energy delivered over a ten period was Rs. 1.25 paise per kWh. The average realization, including agricultural consumption, was Rs. 0.97, 28.5 paise less than the cost. Whereas the average realization, excluding agricultural consumption, was Rs. 1.21 paise per unit, 4.5 paise below the cost.

3.7 Technical parameters of power sector

T&D losses in the power system in India continued to remain high during the Sixth and Seventh Plan periods. These losses increased, both in percentage terms and in absolute terms during the 1980s. In percentage terms, it was about 22.9 percent during 1991-92, against the normal expected T&D loss of 12 percent. These losses can be attributed to both technical losses and commercial losses:

- Technical losses are due to extension of the low tension distribution network to cover wider areas of low load densities with long lines, and low quality transformers and other equipment.
- The commercial losses (also known as non-technical losses) include theft, pilferage, unmetered supplies, defective meters, etc.

There are no scientific studies available to determine the extent of T&D losses, due to technical and non-technical losses. Transmission losses are in the range of 5-7 percent, while the bulk is taken by distribution losses which include non-technical losses.

T&D losses valued at average cost in 1991-92 prices and long run marginal cost were estimated for the Eighth and Ninth Plan periods under BAU and efficient scenarios as given in Table 17. The long run marginal cost for energy, worked out by us, is Rs. 1.61, which is Rs. 0.36 more than the average cost. These losses are very substantial to the economy, which can be reduced through minor investments in the T&D network. During the Eighth and Ninth Plans, steps are to be initiated to reduce the T&D losses through modernization and renovation of the existing network, besides new investments. These measures are expected to reduce T&D losses by 3 percent during the Eighth Plan, and a further 4 percent during the Ninth Plan. If these losses are reduced to these levels, substantial gains will accrue to the electricity boards.

3.8 Productivity ratios

The productivity indicators of employees of the Electricity Boards and Electricity Departments in the country are given in Table 18. The total number of employees has gone up from 791,600 in 1980-81 to 968,500 in 1990-91. The number of employees per million kWh sold has drastically come down to 5.3 in 1990-91 from 106.6 in 1980-81, which showed a reduction of 5.3 percent per year. The employees per 1,000 consumers has come down to 16.8 from 29 during the same

Table 17
Transmission and distribution losses forecasts of energy losses

Scenario	Under BAU scenario	Under efficient scenario	At Rs.1.61 BAU scenario (Rs. crores)	At Rs.1.61 efficient (Rs. crores)
1992-1993	8342	8052	10744	10370
1993-1994	8966	8338	11548	10739
1994-1995	9697	8685	12489	11187
1995-1996	10490	9059	13511	11668
1996-1997	11727	9770	15104	12583
1997-1998	12162	8680	15664	12479
1998-1999	13059	9946	16820	12810
1999-2000	14017	10210	18053	13150
2000-2001	15025	10370	19352	13356
2001-2002	16084	11205	20716	14432

Computed based on the Data.
Source: 1) Current energy scene in India, May 1993, CMIE
2) Annual Report of working of SEBs, Electric Department, Planning Commission, August 1991.

Table 18
Productivity indicators of employees

Year	No. of employees '000s	Employees per GWh sold	Employees per 1000 consumers	Power generated per employee
Lakh units				
1980-81	791.6	10.6	29.0	1.40
1984-85	857.3	8.6	22.3	1.83
1985-86	885.3	7.8	20.9	1.92
1986-87	897.2	7.4	20.1	2.09
1987-88	920.4	7.0	19.1	2.11
1988-89	957.4	6.4	18.3	2.31
1989-90	966.7	6.1	17.4	2.53
1990-91	968.5	5.3	16.8	2.73

Source: Annual Reports of Working of SEBs, & Electricity Depts.

period, whereas the power generated per employee has almost doubled during this period. It shows that the productivity of labor in the electricity boards has increased significantly.

4. Assessment of economic cost

The main objective of any long-term capacity expansion requires an assessment of the most likely demand growth and also the various benefits that will accrue from existing as well as newly planned capacities. The likely benefits, in terms of available energy, from the existing as well as new projects, and the costs associated with the running of the system have to be assessed on the basis of past performance of the power sector. With a view to assess the future supply position, the Central Electricity Authority (CEA), based on their analysis and study of the past performance of power projects, has evolved some norms. These norms were adopted in developing the Eighth FYP. These norms are given in Table 19.

There is no outage in hydropower plants and auxiliary consumption is only 1 percent in them. Adopting these norms, the extent of loss due to outages, both forced and partial valued at long run marginal cost (LRMC), were calculated for the years 1992-93 through 2001-2002. These are presented in column 1 of Table 20.

Table 19
Peaking capacity of power projects (%)

Item	Thermal units	Gas turbine units
1. Planned maintenance	10	15
2. Forced outage rate	14	10
3. Partial outage rate	9	10
4. Auxiliary consumption	10	1
5. Spinning reserve	5	5
Peaking capability	58	59

It is possible to reduce the partial outage in the power system. If these are reduced, the gains that would be generated in the system are given in column 2 of the Table.

The unmet demand for power has been worked out by the Planning Commission for all India, region-wise and state-wise for Eighth and Ninth FYPs. This has been taken as the BAU scenario. In the western region, the performance of the system is efficient compared to the southern and northern regions. This has been taken as the efficient scenario, which is applied for all India, and this norm is applied to compute the power availability. Since demand does not change, the difference between the availability and the requirement is computed to determine the unmet demand valued at LRMC and presented in Table 21. Under the BAU scenario, the total value of loss due to unmet demand during the 1992-2002 period is estimated to be Rs. 110.13 billion. Whereas under the efficient scenario, it is estimated that the gains will be in the order of Rs. 212.07 billion during this period. Under the

Table 20
Cost of forced and partial outages

Year	Cost due to outages at LMRC (Rs. billion)	Possible gains if outages can be reduced by 9% valued at LMRC	Net cost (Rs. billion)
1992-1993	112.1	72.1	40.0
1993-1994	122.4	78.7	43.7
1994-1995	132.9	85.4	47.5
1995-1996	144.5	96.0	48.5
1996-1997	150.2	101.1	56.22
1997-1998	173.3	111.3	62.0
1998-1999	185.5	119.2	66.3
1999-2000	199.1	127.9	71.2
2000-2001	212.5	136.6	75.9
2001-2002	231.8	149.1	82.7

Table 21
Unmet demand for electricity (billion Rupees)

	Unmet demand valued at average prices		Value of loss due to unmet demand at LRMC = 1.61	
Year	Business as usual scenario	Efficient scenario	Business as usual scenario	Efficient scenario
1992-1993	18.24	-1.52	29.36	-2.48
1993-1994	16.64	-9.45	26.79	-15.21
1994-1995	15.89	-25.11	25.58	-40.42
1995-1996	-6.50	-5.89	-10.45	-9.48
1996-1997	9.76	+4.90	15.71	7.89
1997-1998	0.44	-7.04	0.71	-11.29
1998-1999	1.42	-20.79	2.28	-33.46
1999-2000	2.41	-6.64	3.87	-10.69
2000-2001	5.15	-21.40	8.28	-34.45
2001-2002	4.97	-38.81	8.00	-62.48
Total	110.13	212.07		

Note: The negative sign denotes surplus availability.

Table 22
Generating inefficiency losses (1985-86 to 1991-92)

Year	*Loss due to auxiliary consumption (Rs. billion)*	*T&D losses in excess of 12% of generation (Rs. billion)*	*Excess cost due to oil (Rs. million)*
1985-86	21.29	20.61	1825
1986-87	24.03	22.27	1803
1987-88	27.66	25.48	1793
1988-89	29.38	28.46	1575
1989-90	33.30	33.40	535
1990-91	34.78	36.00	1118
1991-92	38.91	39.06	2711

BAU scenario, the losses are estimated to come down during the Ninth Plan compared to the Eighth Plan, whereas in the efficient scenario the gains increase during this period. Generation inefficiencies continued to persist in the power system in India. These are in the form of low plant load factors, excess of T&D losses compared to international standards, high auxiliary consumption, and high fuel oil costs. The auxiliary consumption in hydropower stations is very low. Hence the loss due to auxiliary consumption is computed for thermal stations. In computing T&D losses, a threshold level of 12 percent is taken, since much of this loss is unavoidable in the system. Since T&D losses are in excess of this 12 percent, the loss accrued due to this is estimated. Similarly, the lowest value of oil cost to generate one unit of electricity is taken as the minimum that is necessary to generate one unit of energy. Taking these norms, the losses due to auxiliary consumption, T&D losses, and losses due to oil consumption are presented in Table 22 for the period 1984-85 to 1991-92.

The power system, with generating capacity of 66,087 MW at the end of 1990-91, along with the T&D system spread throughout the country, was employing more than 12 lakh people. The entire manpower in the power sector could be grouped into two categories—technical and non-technical. Manpower can also be broadly categorized as skilled/unskilled. On average, total manpower in SEBs under the state sector comprises of 71 percent technical staff and the rest non-technical. There appears a trend in the decrease of technical manpower.

The CEA has estimated that about 20 percent of manpower is in excess of the requirement. The cost of establishment in the electricity boards has been increasing, though their productivity ratios are increasing. In terms of the cost of establishment/administration, it is increasing from 16.5 paise/kWh sold in 1988-89 to 19.22 paise in 1991-92. With the 20 percent reduction of manpower in the power system, substantial gains can be generated to the SEBs.

The addition to capacity during the Eighth and Ninth FYPs, the sector will need substantial additional manpower. To make an assessment for the requirement of manpower in the Eighth and Ninth Plans, one has to work out additional requirements for additional facilities of generation, besides natural depletion of the anticipated available personnel due to death, retirements, changes in profession, etc. CEA has envisaged a 10 percent reduction in the requirement of manpower per MW with respect to operation and maintenance, and a 5 percent reduction in construction projects.

5. Justification for reforms

The power sector in India has an impressive growth in installed capacity and has an extensive T&D network. Power generation and consumption has also increased significantly over a period of time. The importance of the power sector has been recognized in the early stages of planning particularly from the Fifth Plan onwards. The planned outlays were higher in the power sector, compared to other sectors of the economy.

With the available installed capacity, its utilization is rather low, though it showed marginal improvements in recent years. The reasons for these are high levels of outages and higher auxiliary consumption. Energy generated in the

system is lost excessively before it reaches the consumers. This is because of the inefficient T&D network. The costs of supply of power are higher due to the higher levels of consumption of coal, high operations and maintenance costs, high establishment costs and excessive employment. These factors have led to the high cost of power, below the expected realization of cost. These further led to inadequate mobilization of internal resources, with excessive borrowing from the market and the state government, thus increasing the debt burden of the SEBs. These factors affected the efficient functioning of electricity boards. As a result, it has become difficult for the SEBs to meet their commercial obligations to other organizations.

It was recognized that the PLF of thermal plants was much below the recommended levels and the T&D losses were fairly high. The pricing of electricity was inadequate to generate surpluses, and the quality of power supply was not satisfactory. Time over-runs and cost over-runs were very common in new power projects. These factors have led to the unsatisfactory performance of electricity boards, both on the financial side and the generation and distribution side.

The FYPs have recognized these problems, and emphasized the need to overcome these problems. They assured that the anticipated demands are to be met adequately and in a reliable cost effective manner to increase the performance of the SEBs in the country. The Planning Commission also advised the states from time to time to improve performance of the SEBs, and has taken some measures to implement them. But these measures could not yield the expected improvements in the operation of SEBs. As a result, it becomes necessary to overhaul the functioning of SEBs, through appropriate legislation, as self-sustaining economic enterprises.

The need for reforms is pressing, given the need for increasing economic development. In this paper we traced the macro-relationship between power and economic growth from the viewpoint of some critical parameters. From these, the extent of unmet demand and the requisite supply availability was projected for the Eighth and Ninth Plans. The LRMC of additional generation was calculated to enable quantification of the cost to the economy if reforms are not effected. These costs provide significant justification to reform the power sector.

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Power sector reform in Argentina

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Financing Aid and Cooperation
Secretariat of Energy

Good morning, ladies and gentlemen. First of all, I want to speak a little about my country so that you can have a better understanding of the causes and the goals of the reforms that our government has been carrying out since 1989, especially in the power sector.

1. General information

Presently, in spite of a weak economic performance during the last ten years caused by state intervention in the economy and high levels of inflation, Argentina is still among the wealthiest countries in Latin America in terms of per capita income.

Through a program of substantial economic reform and liberalization over the last three years, Argentina has become one of the fastest growing countries in the region, with Gross Domestic Product (GDP) growing by approximately 6 percent during 1991 and 6.5 percent for 1992.

Our country is the eighth largest country in the world by land area—2.7 million square kilometers—and the second largest, after Brazil, in Latin America. The population is approximately 33 million.

Related to government organization, Argentina has been an independent republic since 1816. The country consists of 23 provinces and the federal capital is Buenos Aires.

Argentina's Federal Constitution is modeled after that of the United States and has been in effect since 1859. Since the end of the last military government in 1983, Argentina has experienced ten years of uninterrupted democratic rule.

2. Economic reform

After President Menem took office in July 1989, his administration implemented a series of reforms, including The Economic Emergency Law and the Law of the Reform of the State,

designed to achieve a major restructuring of the country's economy.

The main features of the initiative included:

- Fiscal reform through privatization of state-owned enterprises, tax reform, and reduced government expenditure
- Reform to ensure monetary stability and lower levels of inflation
- Liberalization of foreign trade
- Deregulation of commercial and financial markets.

The overall structural adjustment program was given greater impetus with the appointment of Domingo Cavallo as Minister of Economy in February 1991. He announced a far-reaching economic reform program, designed to achieve long-term economic growth and low levels of inflation.

One of the cornerstones of the plan was the passing of the Convertibility Law, which made Argentina's currency fully convertible with the United States dollar. The Convertibility Law also prohibits monetary revaluations, indexation of prices, cost adjustments, and other mechanisms for the adjustment of debt, taxes, and prices of goods and services.

The government has implemented a general reform program for public sector companies, which included the adjustment of tariffs for goods and services provided by public sector as well as restructuring and privatization of public sector companies.

The government has included in its privatization plan electricity, telecommunications, ports, airports, water, gas, steel, petrochemicals, and railways. The management of the privatization process is under the responsibility of the Ministry of Economy and Publics Works and Utilities as well as the Ministry of Defense.

3. Energy sector reform: "Why did the government do it?"

3.1 *Introduction*

In 1989, the energy sector was characterized by:

- Thermal generation equipment that was generating at only 40 percent of its capacity, and distribution systems with very bad performance resulting in frequent electricity cuts and low tension
- Huge investments in generating projects, such as Piedra del Aguila, Yacyretá, and Atucha II, were completely stopped and the contractors presented claims against the government
- Low tariffs (good for industrial competitiveness) that reached a similar level to that of other countries such as Uruguay and Chile, with similar costs in 1991, as a result of the price stability achieved with the Convertibility Law. Despite this, these companies ran an annual deficit of approximately U.S. $300 million
- The Treasury was unable to make transfers to the sector due to the hyperinflation crisis in 1989.

3.2 *Strategy*

The strategy that was put in place by the government to solve the problem consisted of:

- Privatizing the companies in the energy sector
- Elaborating a set of laws and regulations for the industry
- Keeping the sector operating.

It was decided to transfer the companies to the private sector without restructuring them, leaving that task to the private owners. For this reason, majority interests were transferred to the new owners to enable them to quickly and efficiently take control of these companies.

The most important steps in the privatization plan were:

- Division of the state-owned enterprises into a sufficiently large number of new companies
- Valuation of the companies according to the Discounted Cash Flow (DCF) approach
- Establishment of contracts between producers and distributors before the sale to develop a long-term market, among others. The decisions taken with respect to these companies include:
  - The legal incorporation of companies as capital societies
  - The sale of the majority interest—in all cases in excess of 50 percent
  - The simultaneous transfer of assets and liabilities of companies in operation at the time of the sale

- The remaining shares in the hands of the government will be sold in the stock market to create a stronger capital market in the country
- Employee Stock Ownership Programs (ESOP) are planned.

4. Energy sector reform: "How did the government achieve its goals?"

4.1 Regulation

The regulation and privatization processes have been based on two laws drafted during 1990 and 1991.

The first law, **State Reform Law Nº 23.696**, provides a framework for the transformation of the entire public sector. Figure 1 outlines the principal aspects of the law. This law allows the government to split up public companies, change their charters, create new corporations from the existing companies, transfer liabilities to the Argentine Treasury, and sell stock of the companies.

The other law is the **Electrical Regulatory Framework Law Nº 24.065**. This law:

- Restructures the energy sector, dividing it into generation, transmission, and distribution activities—leaving generation to the market characteristics while defining transmission and distribution as public services
- Assigns the task of supervision and of setting policies and regulations to the public sector while leaving management decisions to the discretion of the private sector
- Establishes the basic principles of concession for transmission and distribution activities
  - "Open access" for the networks of both transmission and distribution
  - For transmission activities, there is an explicit prohibition against buying and selling, only a toll is permitted; the distributing companies have the obligation to supply electric energy within the concession area.
- Sets tariffs based on real production economic costs and determines profitability levels according to activities with similar risk levels
- Establishes the **Ente Nacional Regulador de la Electricidad**, a national electrical regulatory entity that is separate from any political authority. This agency is to act as a "host" to public hearings and as a mediator between parties that have conflicting interests.

As a complement to these laws, the Secretariat of Energy has devised a regulatory scheme for the sector based on its division in areas with different characteristics (Table 1).

The regulatory principles with respect to distribution are:

- Market concession vs. obligation to lend service
- Rates predetermined by power granted on the basis of marginal costs

Figure 1
Principal aspects of Law No. 23.696

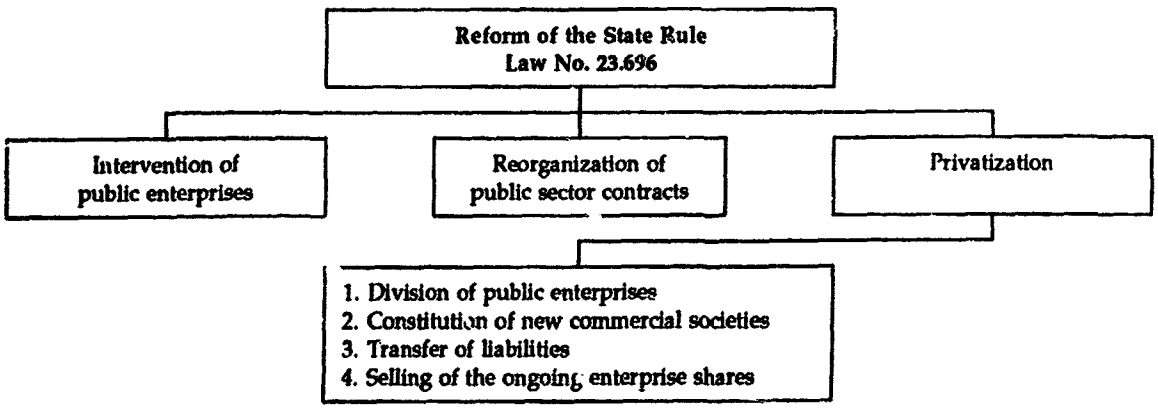


Table 1
Price system and characteristics of productive stages

Stage	*Generation*	*Transmission*	*Distribution*
Characteristic	Competitive Market	Intermediate	Monopolistic
Investment	Projects	Discreet	Continuous
Prices	Free	Marginal cost Failure cost Fixed costs	Marginal cost Failure cost
Regulation	Contract obligations Rate of revenue	Preestablished obligations	Penalty based on required service quality

- Punishment system with repayment to users on the basis of failure costs
- Short periods of negotiation.

Figure 2 outlines how the market works. The market has two prices. One is the **agreed price** for contracts between generators and large consumers or distributors. The other is the **spot price**. This price will be set by offering and demanding electricity in a free market.

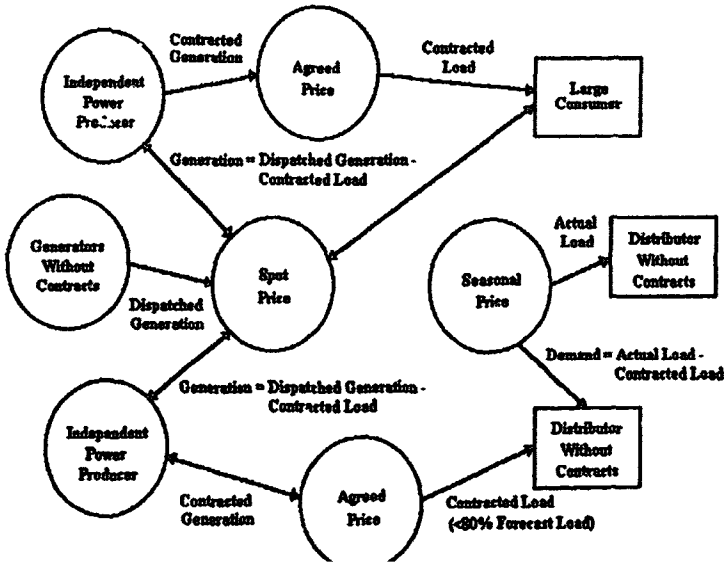
4.2 *Auctions*

The privatization process began once the regulatory framework was established. Table 2 illustrates a basic structure of the bidding process. The process essentially consisted of the interested parties submission of two envelopes. The first envelope had to state the composition of the group, with the corresponding participations and financial requirement, the qualifications of the operator, and the presentation of guarantees. The second envelope contained the bidding offer.

Table 2
Bidding process

Schedule	*Time table (days)*
Beginning of the selling of the condition's tender	0
Optional date for submission	30
First envelope opening	50
Analysis and prequalification	57
Terms for the impeachment	60
Second envelope opening - Pre-Awarding	70
Transfer contract	75
Awarding	90

Figure 2
Operation of the option market



4.3 Results

Table 3 shows a sample of the shareholders and their interests in each of the new companies which were created. Selected financial results for the companies are shown in Figures 3 and 4.

Tables 4 and 5 show the energy sold at the level of production for the entire system for the years 1989 to 1993 and the corresponding wholesale prices. The growth in demand has been accompanied by a recuperation of generation equipment. At the same time, the price of the system has decreased with the increase in the availability and efficiency of thermal generation equipment.

5. The future

5.1 Future scenarios

Projections for the expected energy demand growth are shown in Figure 5. A relatively high growth rate of energy demand of 5 percent is expected until the year 2000, when the growth will continue at a more moderate rate of 2 percent. Figure 6 shows how the thermal stations will be incorporated into the network.

Table 3
SEGBA S.A.

Company	*Date*	*Sale %*	*Name of the group components*	*Part. C/U %*
Central Puerto S.A. (1,009 MW)	4/01/92	60	**Central Puerto S.A.**	
			Chilgener S.A.	82.5
			Chilectra Quinta S.A.	12.5
Central Costanera S.A. (1,260 MW)	5/29/92	60	**Central Costanera S.A.**	
			Endesa de Chile	50.0
			Enersis S.A.	15.0
			Dist. Chilectra Metro. S.A.	5.0
			Inversora Patagonica	12.5
			Inter Rio Holdings Est.	12.5
			Costanera Power Corp.	5.0
Central Pedro de Mendoza S.A. (94 MW)	9/22/92	90	**Central Pedro de Mendoza S.A.**	
			Acindar S.A.	75.0
			Massuh S.A.	25.0
Central Dock Sud S.A. (211 MW)	8/31/92	90	**Central Dock Sud S.A.**	
			Polledo S.A.	100.0
EDENOR S.A.	8/31/92	50	**Electricidad Argentina S.A.**	
			Astra Capsa	40.0
			Electricite de France	20.0
			Endesa de España	10.0
			Empresa Nac. Hidroelectrica del Ribagorzana S.A.	20.0
			Societe d'Amenagemeny Urbaine et Rural	10.0
EDESUR S.A.	8/31/92	51	**Distrilec Inversora S.A.**	
			Cia. Naviera Perez Companc SA	40.5
			Grupo PSI Energy Inc.	10.0
			Distribuidora Chilectra Metropolitana	20.0
			Enersis S.A.	19.5
			Endesa de Chile	10.0
EDELAP S.A.	12/18/92	51	**Cia. de Inv. Electricidad S.A.**	
			Houston Arg. S.A.	49.0
			Techint S.A.	51.0

Figure 3
Work plan for electric loss reduction - EDENOR S.A.

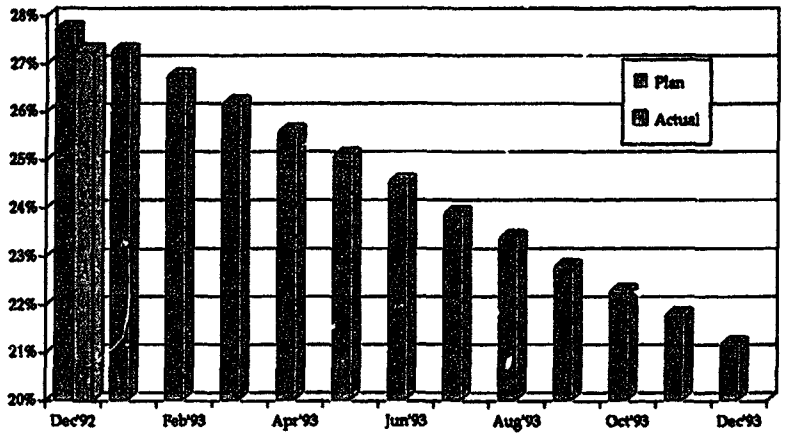


Figure 4
Evolution of unavailability - Central Costanera

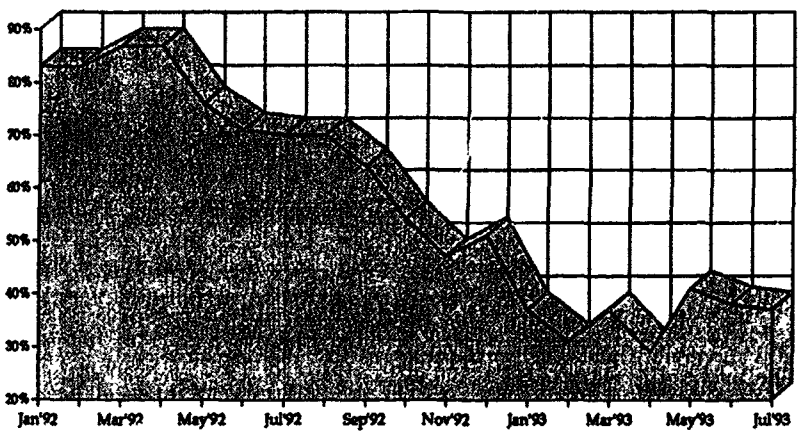


Table 4
Production of energy

Year	*Energy GWh*	*Annual Difference*	*% Increase*
1989	43,200	—	
1990	24,800	(400)	(1)
1991	46,100	3,300	8
1992	50,020	3,920	9
1993 (est.)	52,000	1,980	4

With oil and gas basins located throughout Argentina and the network of gas pipelines and electrical power lines, numerous different combinations and alternatives can be developed using thermal stations that can be installed in the well head or close to the demand, concentrated principally in the Buenos Aires area. These plants can also work as "peak shavers".

The gas system, organized similarly to the electric system, is divided by sectors: distribution and transportation. Future development will be based on free market forces.

Table 5
Spot prices

Year	*Spot price US$/MWh*	*Annual average US$/MWh*
1991		39.63
Aug	46.49	
Sep	42.02	
Oct	37.27	
Nov	32.03	
Dec	40.35	
1992		48.61
Jan	38.46	
Feb	43.65	
Mar	57.76	
Apr	42.21	
May	46.17	
Jun	59.79	
Jul	76.33	
Aug	57.90	
Sep	48.15	
Oct	44.39	
Nov	36.47	
Dec	32.05	
1993		38.60
Jan	39.60	
Feb	40.98	
Mar	43.00	
Apr	43.47	
May	38.53	
Jun	35.61	
Jul	33.46	
Aug	34.15	

5.2 The remaining task

Only four large issues remain to be solved in the public sector to complete the organization of the system. They are the following.

First, the government sells the remaining shares that it owns in the privatized companies. Table 6 illustrates the list of companies, the percentage of shares still held by the government, and the value of those shares based on the price initially offered for the majority. This process will most likely begin towards the end of the year with the sale of the remaining shares of Central Puerto S.A. and Central Costanera S.A.

Second, Table 7 shows regional distribution companies in the hands of the provinces of Buenos Aires, Córdoba, and Santa Fe. Although the national government does not have direct interest in these companies, transfer steps will soon take place in the provinces of Santa Fe and Buenos Aires, and most likely in the Provinces of Corrientes and Misiones, among others. It is our belief that the whole country will follow this policy for which reason we can expect a gradual but sustained transfer of the distribution companies to the private sector in the next two years.

Third, Figure 7 shows the timetable for the remaining companies, the installed capacity, and the tentative date for the initiation of the bidding process.

Figure 5
Total consumption of electricity (GWh)

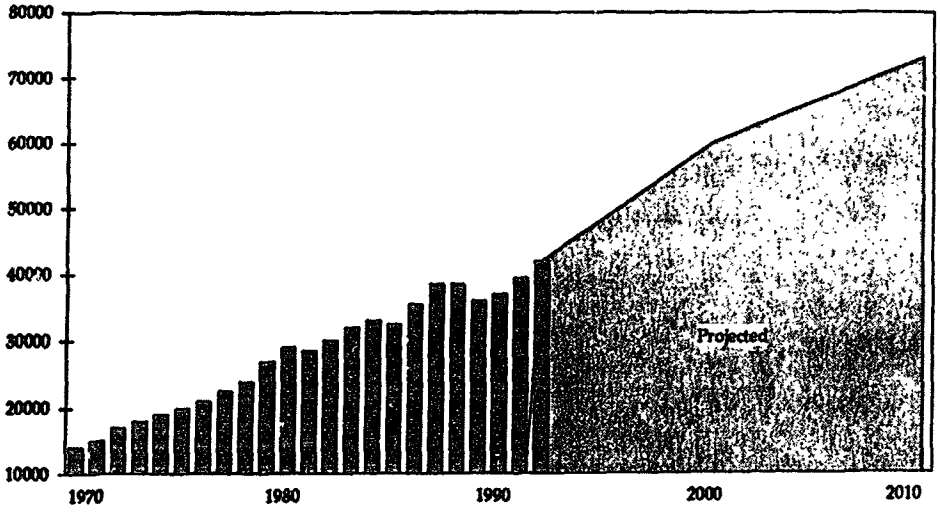


Figure 6
Interconnected electricity grid - future additions ('000 GWh)

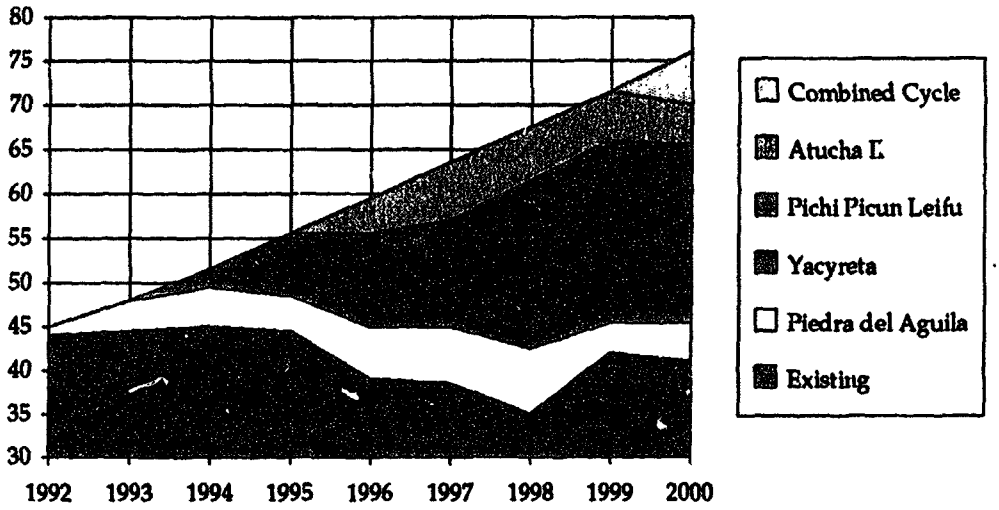


Table 6
Remaining shares

Company	*Shares %*	*Amount US$ million*
Central Puerto S.A.	30	46.1
Central Costanera S.A.	30	45.1
Central Termica Guemes S.A.	30	43.1
TRANSENER S.A.	25	90.0
EDENOR S.A.	39	340.8
EDESUR S.A.	39	390.9
EDELAP S.A.	39	106.3
Total		**1,062.1**

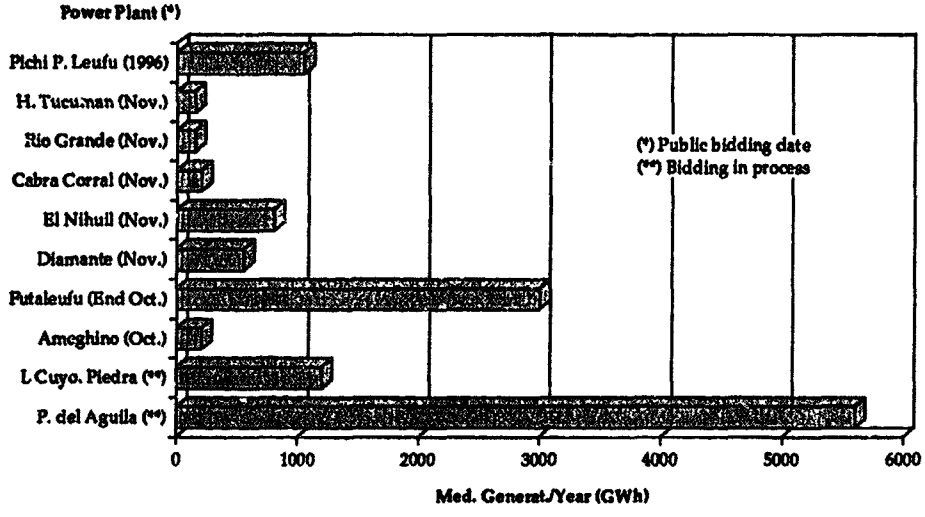
Finally, the remaining issue to be solved in the energy sector in Argentina is related to natural gas. The well head price which is still fixed by the government is due to be lifted in June 1994. Due to the fact that there is still no market structure in existence, the government is studying the best way to free the price to establish competition among the producers, and prevent physical limitations and bottlenecks which result in practices that affect price and do not arise from supply and demand.

Table 7
Electric power sector distribution markets*

		Sales to final user (GWh)			
Jurisdiction	*Enterprise*	*Domestic*	*Industrial*	*Others*	*Total*
Capital Federal y	EDENOR S.A	2,330	2,827	1,348	6,505
Gran Buenos Aires	EDESUR S.A	2,100	2,905	1,605	6,610
Buenos Aires	ESEBA	600	2,500	600	3,700
Cordoba	EPEC	650	800	450	1,900
Mendoza	EMSE	400	1,000	500	1,900
Rio Negro	ERSE	150	800	130	1,100
San Juan	SESJ	130	110	110	350
Tucuman	EDTSA	270	300	180	750

*These markets comprise 55 percent of total public sector electricity sales.

Figure 7
Power plants to be transferred to the private sector



Power sector reform in China

by
Ye Rongsi, Vice President
China Electricity Council

Ladies and Gentlemen:

It is my pleasure to be here in Jaipur, the Pink City, to attend what I am sure will be a very beneficial seminar. I would like to take this opportunity to present an outline of power sector reform in China based on what I know.

1. Present situation of the power industry

Since the foundation of the People's Republic of China, through more than 40 years of development and construction, China's power industry has achieved great success. Now it is entering a new stage in developing large power units, large power networks, extra-high voltage, and advanced automation. By the end of 1992, the national installed generating capacity had reached 165 GW, with annual electricity generation amounting to 747 TWh. China now has 25 large power plants, each with installed capacity over 1 GW (4 hydropower and 21 thermal). Also there are four interprovincial networks, each with installed capacity more than 20 GW, and three other grids, each with installed capacity of more than 10 GW. Trunk frames of 500 KV and 330 KV have been formed initially in each main network.

Although China's power industry has made considerable progress, it still does not keep pace with the demands of our nation's rapidly developing national economy and quickly improving living standards. The power shortage has lasted for more than 20 years. According to estimates, the national power shortage in 1988 reached 80 TWh. In the most recent five years, the newly added installed capacity was relatively great and amounted to 60 GW. In 1990 and 1991, the growth of GNP tended to slow down, and the contradiction between supply and demand was alleviated in the nation as a whole. Since last year, the state has decided to further speed up reform, open to the outside world, and take this favorable opportunity to quicken the development of the economy. In 1992, the growth rate of GNP was 12.8 percent and industrial output value rose 20 percent, but electric power grew only 10.3 percent. Most power networks once again faced a tense situation between supply and

demand, and many provinces and municipalities had to maintain the supply and demand balance by load curtailment.

After the Fourteenth Communist Party Congress, the State Council readjusted the national economic development plan, which was approved by the Eighth NPC, held in March 1993. According to the readjusted plan, the annual average growth rate of GNP was to increase from the previously set 6 percent to between 8 and 9 percent, and the target of quadrupling GNP over that of 1980 is to be realized in 1998, or two years in advance. Meeting the demands posed by an annual average national economic growth rate of 8 to 9 percent will place a heavy burden on the power industry. Based on the original plan of an annual average GNP growth rate of 6 percent, the state previously made a plan that national electricity generation would reach 810 TWh by 1995, at an annual average growth rate of 5.6 percent. Now, after the readjustment of GNP forecasts, national electricity generation will have to reach 920 TWH by 1995, at an annual average rate of 8.2 percent.

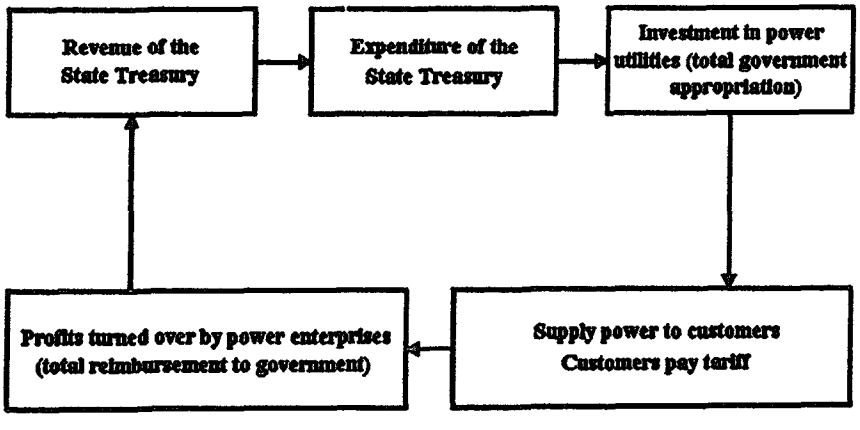
2. Background of the power sector prior to reform

Before the early 1980s, under the centrally planned economic system, the power sector incorporated the administration and enterprise functions in one. The Ministry of Electric Power (MOEP) or the Ministry of Water Resources and Electric Power (MWREP), the Regional (inter-provincial) Electric Power Administration (REPA), the Provincial (Municipal or Autonomous Regional) Electric Power Bureau (PEPB), the Cities' Power Supply Bureaus (CPSB) and the Counties' Electric Power Bureaus (CEPB) had both governmental and power enterprise functions.

The central government owned and had direct managerial control over the entire power sector. The government directly controlled and managed the power sector's production, marketing, sale, procurement, wages, and financing. All production and operational activities were carried out in accordance with the plan approved by the government. Newly built generating capacity, electricity generation, equipment retrofitting, electricity sales, and equipment and materials procurement, had to conform to the plan. Personnel, labor, and payroll management were also under government control. Senior personnel were appointed by the government. The total number of workers in an enterprise was fixed by the government. The grade levels and total salaries and wages were set by the government, and any person that was transferred had to bring along his salary index. In short, the power utilities had no autonomy.

The management of generation, transmission and distribution activities of inter-provincial networks or independent provincial networks was vertically integrated. REPA and some independent PEPBs are legal entities. PEPBs

Figure 1
Relationship between power enterprises and the state



under the REPAs had no status as a legal entity and no independent accounting system.

The state adopted a financial management system of "total reimbursement to and appropriation from government" and "detached control over revenue and expenditure" for power enterprises. The earnings of power enterprises were thus entirely turned over to the state, and their funds, in turn, were allocated from the State Treasury. The capital construction fund of the power industry came from a single source (i.e., appropriations from the State Treasury). Power enterprises were entirely under the administrative command of the government and had no autonomy in financial decisionmaking and dispatching. With no competition and no risk, the sector lacked vitality and self-development capability. This kind of financial management system formulated a one-way enclosed loop economic relationship between the state and power enterprises (see Figure 1).

The power sector was responsible for plant construction and operation, except for some small thermal and hydropower plants that were built and operated by other sectors. There was no private sector involvement in financing and operating newer plants.

The single tariff system of electricity pricing was set by the central government in 1955 and lasted for 30 years. National average electricity price levels are shown in Table 1.

Serious shortages of power resulted from the lack of construction funds. For example, from 1981-85, the average growth rates of installed capacity and generation were only 5.4 percent and 6.4 percent, respectively; 5.6 percent and 4.6 percent, respectively, behind the growth of the national economy.

To sum up, the pre-reform situation under the system of the highly centralized, planned economy, China had a combined and government-demanded operational system, a financial management system of total reimbursement to and appropriation from government, and sharp policy restraints on state investment, tax revenue, credit, tariffs, etc., and so on. The effect of this was to suffocate the vitality of China's power enterprises and to shackle the development of China's power production. These shortcomings then led to acute power shortages during the Sixth and Seventh Five Year Plan periods (1981-90). The power crisis showed that reform was imperative and led to the restructuring of the power sector during the past 10 years.

3. Main reforms implemented and ongoing implementation

Over the past 10 years, power sector reform has made breakthrough progress in some important areas.

3.1 Reform of power investment

In the early 1980s, power investment shifted from government appropriations to loans and payable uses of funds. According to the document "Tentative Stipulations on Encouraging Fund-raising for Power Construction and Implementing Multi-rate Tariff" issued by the State Council in 1985, the monopoly of the central government on power investment has been changed to multi-channel fund raising, which mobilizes local governments and power consuming enterprises to participate in power investments. In power construction, competitive market systems were introduced, pushing forward the contracted system of responsibility for the owners, and tendering contract and construction supervision systems.

Private investment was permitted, and foreign investment was encouraged. Since 1984, the state has been encouraged to use foreign funds massively to develop the power industry. By 1992, U.S. $8.9 billion of foreign funds was invested, of which a small part was in the form of direct investment. Some Chinese foreign joint ventures, such as Huaneng International Power Development Corporation and the Xinli

Table 1
Average electricity prices, 1953-85

Period	*1953-58*	*1959-65*	*1966-70*	*1971-75*	*1976-80*	*1981-85*
Yuan RMB/kWh	64.16	74.33	66.48	65.96	65.94	70.85

(Sunburst) Power Company, were set up on the state level. Some Chinese-foreign cooperative power plants were also set up such as the Shajiao B Power Plant in Guangdong Province.

3.2 *Reform of the mono-tariff system of electricity to a multi-tariff system*

The tariff for electricity generated from power plants owned by the local governments, institutions other than the central government and central power sector, Huaneng, Xinli, and other joint venture companies is priced and verified based on the real cost, plus taxes and a reasonable profit.

In line with the escalation of coal prices and transportation charges that increase operating costs, tariffs are raised correspondingly.

For simplifying the rate schedule, different tariffs have been combined and levelized into a single rate schedule in some provinces. But the tariffs for electricity generated by the state-owned power plants and the plants already in operation before the reform remain unchanged.

3.3 *Progression of power enterprise reform*

Based on the principle of "separation of administration from enterprises, real entities on provincial bases, united networks and unified dispatching, and joint financing for power construction" that was put forward by the state in 1987, and the "Scheme of Institutional Reform on Power Industry Management" raised by the Ministry of Energy and approved by the State Council in 1988, the East, Central, North, and Northwest China Power United Companies and the Northeast Power General Company, as well as several provincial power companies, were set up in succession. These companies are economic and legal entities with independent accounts, organized from enterprises of diverse ownership. In managing the power network, they have been utilizing economic, technical, and legal measures instead of administrative mandates. On these bases, the North, East, Northeast, Central, and Northwest Power Groups in China were established in January 1993. Twenty-one of the thirty provincial power companies joined the power groups that practice individual planning, and independently contracted projects from the state with more autonomy in operations. In addition, some 1,500 county-level distribution companies, two-thirds of the total, became bulk purchasers and independent legal entities with their own accounting systems.

3.4 *Reform of profit sharing*

In the early 1980s, power companies implemented the "Enterprises Fund," "Retained Profits," and the first and second stages of "Profit Submission Transformed into Tax" systems in succession. Since 1988, power enterprises were contracted with the responsibility system, in which enterprises were allowed to retain their operating surplus if they "turned over the prescribed profits, after completing technical innovation tasks, electricity sales, and materials consumption, linked with the total amount of payroll." This reform has strengthened enterprise management and the sense of economic efficiency and has raised enthusiasm in system operations.

3.5 *Reform of the internal management system within enterprises*

According to the "Enterprise Law," all enterprises should implement the director (manager) responsibility system. To put this law into effect, reforms in labor, payroll, and personnel systems in the power enterprises were launched in 1992, through which the organizational setups and personnel management within the enterprise are being significantly reformed. This reform is now spreading.

3.6 *Reform in the accounting system*

The state issued the "General Rules on Enterprise Finance and Enterprise Accounting Criterion," which were put into effect on July 1, 1993, to conform with international practices.

3.7 *Stock systems*

Stock systems have been employed in some state-owned enterprises since 1992. A few power enterprises were approved to issue intracompany stocks. Some issued marketable stocks to the public. Thus, the general public and the employees of the power industry are beginning to own a small portion of power enterprise assets.

3.8 *Transformation of the government function*

In the government, reform meant that functions were changed, offices were simplified, and authority was distributed to lower departments. Good progress was made in returning autonomy to the power enterprises. The newly established

Ministry of Electric Power is determined to transform its functions from direct administration to providing "planning, coordinating, and supervising" services.

Through the above-mentioned reforms, new investments have emerged in China's power industry. In 1993, total investment in the power industry reached 53 billion Yuan, an increase of 32.5 percent from 1992. Of this new capital, approximately 70 percent came from multi-channel funds. In 1981-85, the commissioned average annual generating capacity was only a little more than 300 MW. In the recent five years, newly installed generating capacities reached 1,260 MW annually. Reform has steadily improved the management and the profits of China's enterprises. A lot of high-quality, efficient, and economic capital constructions were undertaken in the power industry. In recent years, coal consumption decreased more than 3 g/kWh. Equivalent availability factors of large generation sets increased annually.

4. Main issues currently faced

Great success has been achieved in the development and reform of China's power industry. But there is still much work to be done to deepen reform and accelerate development. The main issues currently faced are as follows:

- The government still intervenes too meticulously in the enterprises. The enterprises do not have complete autonomy in their decisionmaking. Power enterprises are not separate from the government, and continue to undertake a lot of the administrative functions. For example, the government allocates power to customers. This inseparableness hampers the power enterprise from becoming a real legal entity with the capability to run, develop, discipline itself, and be accountable for its profits and losses.
- The power group corporations and provincial power companies have not yet been corporatized.
- There is no competition among enterprises. Thus, there are less incentives to cut down operating cost, improve efficiency and promote profitability.
- The rational economic tariff system has not been utilized.
- Power enterprises have less internal funds for expansion and alleviating the power shortage. The scarcity of capital, lack of fuel supply, and delays in transmission network construction also obstructs the development of power industry.
- There is a lack of a comprehensive legal system to suit the requirements of a socialist market system.
- There is a lack of an efficient and effective macro-control.
- Regarding power planning, power investment, electricity laws and regulations, tariff and policies from multi-sectors, the process is complicated, decision-making is slow, and small local generation plants are often not coordinated with the overall demand.

5. Objectives of power sector reform

5.1 Principles of setting reform objectives

These are as follows:

- Contribute to the general goal of national reform to establish a socialist market economy system.
- Build from the existing conditions of the power sector in China.
- Use the experience of other countries for reference.
- Ensure the conformity between reform objectives and development goals.

5.2 Main points of reform goals

In my view, the main reform goals can be divided into several categories: general, shifting government function from overall operation to performing only the necessary central functions, corporatizations of the utilities and more thorough going commercializations of main operations, and development of a comprehensive legal and regulatory framework in the sector.

GENERAL DESCRIPTION:

- Separate government administration from enterprise management: "Two rights (ownership and operational right) should be separated."
- Corporatization of the enterprises' organization.
- Commercialization of the companies' operation.
- Legalization of power regulation.

SHIFT OF GOVERNMENTAL FUNCTION TOWARD NONINTERFERENCE IN ENTERPRISES' DAILY MANAGEMENT:

- The main duties of governmental administrative departments include: law and policy formulation; overall planning; investment quantity control; major projects approval; supervision of the state property value guarantee and value addition; and appointment of state-owned shares representatives.
- Power control functions (such as tariff review, franchise license, etc.) should be relatively centralized. The "Power Regulatory Commission" should be set up to review and authorize legal and regulatory functions (although this arrangement will be rather difficult, it is an option that should be considered). The national power regulatory authority may be transferred away from the power administrative departments gradually. In the meantime, the government may also (a) transfer the obligations of formulating policies and rules to the pertinent governmental departments (may be a comprehensive economic department); and (b) transfer grid control duties to a national power dispatching agency or national/regional power group companies.
- Power companies shall have no administrative functions and shall not use two nameplates for one entity. The provincial power regulatory commission can be set up as a provincial power bureau with independent organization and operational rights.
- The electricity council shall further implement their pacts in trade management and services.

CORPORATIZATION OF ENTERPRISE ORGANIZATION:

- Reorganize interprovincial power group companies, provincial power companies, and other power entities according to the "Corporation Law" issued by the state. Most of them will be reorganized first into limited-liability companies. Some suitable ones may be altered to limited-share companies. Distinguish ownership and shareholding rights on the basis of re-evaluating properties. Separate ownership and operational rights. Put into practice a system of having a general manager under the leadership of a board of directors. Implement a new accounting system that can meet international standards.
- Following the construction of the Three Gorges Hydropower Station, and the implementation of a united power grid in the whole country, it will be possible to organize a national power grid company and to set up an intergrid power market.
- Make the provincial power company a legal entity, and let regional generation, transmission, and distribution control be managed by a sole entity. Another option is to let regional generation and transmission be controlled by a single entity, but have a relatively independent county power company manage power distribution. It is also possible to manage an interprovincial grid as a whole or to have one or more power companies within a province.
- An interprovincial power group company will control the grid trunk frame and some important peak-regulating power stations. Its transactions with the provincial power companies are through property control shares or shareholding.
- Public ownership will comprise the majority of shareholding rights of the companies. Under such a premise, a part of small power plants may be leased to or operated by private companies, with properties still owned by the state. Some of them may be put up for auction. One may transfer a small part of state-owned property (e.g., 10 percent) to the general public or as employees' shares.

COMMERCIALIZATION OF COMPANY OPERATION:

This process should have the following features:

- Companies should have full autonomy rights in power generation, operation, procurement, electricity sales, employee management, and organization arrangements.

- Companies shall have the capacity to generate self-developing funds of their own, and functions to collect funds from the market, get loans from banks, and issue shares and bonds upon approval by the state.
- Companies should diversify business wherever necessary. Maintenance work and other productive and accommodation services may be separated from the company as an independent entity with its own accounts.
- Nonoperative properties such as hospitals and buildings should be separated from power companies. The nonoperative segments should operate as independent contractors.
- Internal accounting units should be minimized and set as independent contractors.
- Economic tariff options should be planned, calculated, and applied according to reasonable tariff principles set up by the state. To set power consumption allowances according to China's social goals, a responsibility contracted system must be established.

LEGALIZATION OF POWER CONTROL, CONSUMMATION OF LEGAL POLICY FRAMEWORK:

To develop a legal and policy framework, the following points are critical:

- Set up tariffs according to the principle of cost+tax+reasonable profit, and assure self-reliance. Tariffs will be approved by the government or power regulatory authorities.
- While practicing economic tariff and assuring internal funds for capital expansion, stop imposing two cents per kWh for power construction funds that are not commercialized and are not based on standard methods. Transition measures should be arranged.
- According to pubic utility requirements, decrease circulation tax to 5 percent and income tax to less than 3 percent.
- Power companies shall be operated according to the "Law of Enterprise" and "Transition Management Rules for State-Owned Enterprises" issued in 1992. When the "Corporation Law," becomes effective, reorganize the company and operate according to the new law.
- Establish a legal system to control power companies. This system should lay down the "Electricity Law," supplemented by rules and regulations for tariff control, electricity supply and service control, power development project permits, business area franchise, electric facilities protection, power grid control and regulation, and rules that encourage private and foreign investors to build power stations. If a central and local power regulatory commission is set up, organization and regulatory rules for it will be needed.

China's power sector reform is complicated and has a long way to go. We will gradually reach the goals as long as we persevere within the socialist market economy orientation.

The U.K. experience

by
Roger Witcomb, Director of Corporate Planning
National Power PLC

Good afternoon, ladies and gentlemen. I work for National Power, the largest private generator in the U.K., and I should like to give you a practitioner's view of our new electricity market.

1. The U.K. arrangements

The restructuring of the electricity supply industry in the U.K. was a most complex piece of economic engineering.

The former structure (Figure 1) consisted of a single, publicly owned corporation, the Central Electricity Generating Board (CEGB), which owned the power stations and the high-voltage transmission system, and 12 regional organizations, also publicly owned, which owned the low-voltage distribution system, bought power in bulk from the CEGB and sold it on to final customers.

Under the new arrangements (Figure 2), the 12 distribution companies were sold off as 12 independent companies. The major surgery was saved for the old CEGB, which was split into no less than four companies. The transmission system was hived off as an independent common carrier. The power stations divided between three companies. The nuclear stations went into Nuclear Electric, which is still in public ownership because it was thought unsalable, while the thermal stations were divided between two companies, National Power and PowerGen. In addition, a completely new market was created for electricity, called the pool, which I'll come back to later.

2. Reasons for restructuring

Why did the Thatcher administration decide to restructure the industry so comprehensively? The first thing to remember is that electricity was part of a much larger program of privatization. The official reason for this program was a belief that it was not the business of the government to run industrial concerns. It was felt that without the stimulus of the profit motive or competition, the nationalized industries had

Figure 1
The industry before March 31, 1990

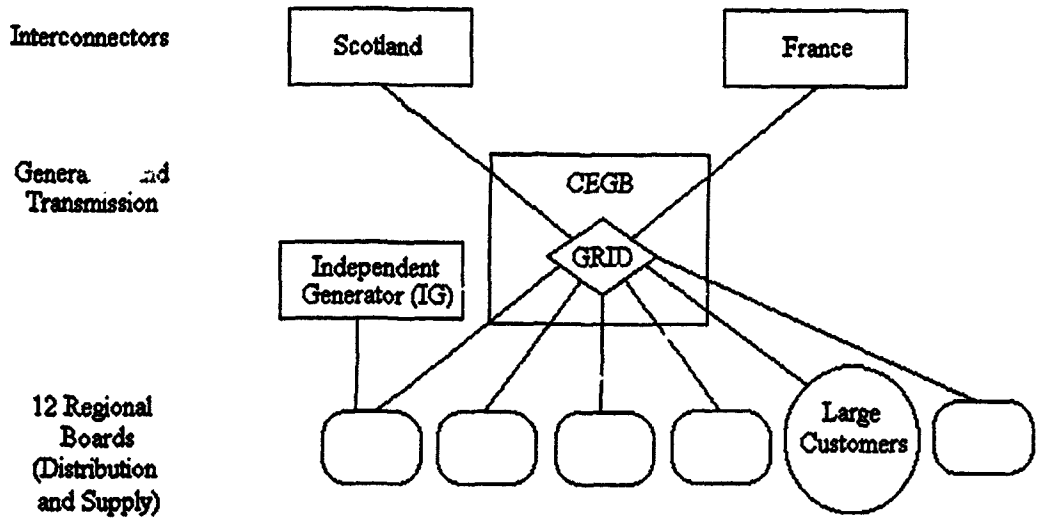
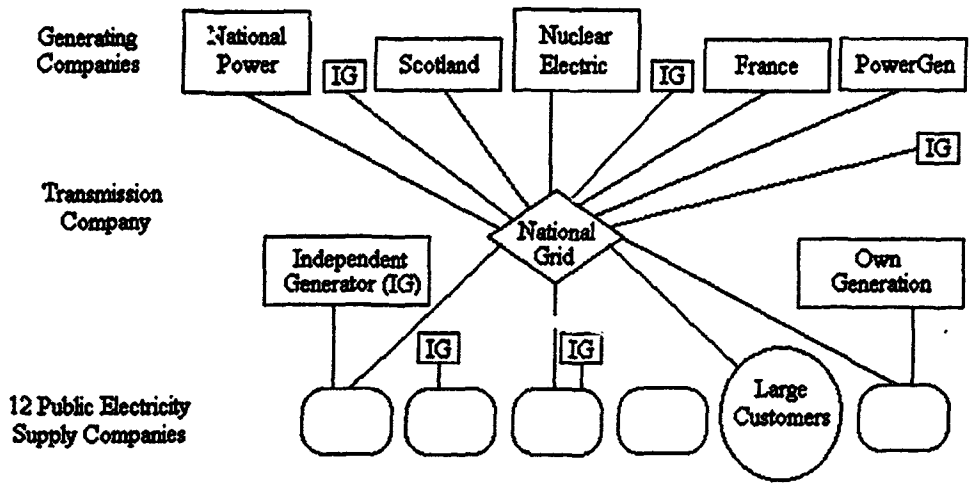


Figure 2
The industry after vesting on March 31, 1990



National Power, PowerGen, Nuclear Electric, and National Grid = Successor Companies to CEGB

become inefficient and bureaucratic. Poor investment decisions were being taken, and there was also a feeling, although this was not often articulated, at least by those in government, that the government could not be trusted to treat these essentially commercial undertakings as just that, commercial undertakings, and would always be tempted to use them as instruments of government policy.

Moreover, attempts to control nationalized industries were thwarted by a management that was better informed than their political masters and had a different set of objectives. All these features were present in the U.K. electricity industry. The costs of investment were excessive. It is generally believed that under the CEGB, power stations cost between 50 and 100 percent more than in other developed

countries and that they took twice as long to build.

The industry was over-manned. This was generally believed to be true, but I don't think anyone realized how bad things were. For example, when National Power was created in 1990, we had over 17,000 employees. Now, three years later, we have little more than 7,000 staff.

The electricity sector was undoubtedly also used as an instrument of government policy. For example, the CEGB was allowed to buy only British coal at well above market price. It was, to a large extent, obliged to buy its plant from British manufacturers. This contributed to its high investment cost, and by feather-bedding British plant manufacturers, it more or less destroyed their chances of ever being competitive in international markets. It allowed British Rail to extract monopoly rent from the generating sector to make its own results look more respectable. The CEGB also invented implausible schemes to justify selling power to industrial users at very low prices. For all these hidden subsidies, domestic consumers and small businesses picked up the bill (the opposite to most developing countries).

By the time it was electricity's turn to be privatized, there was another item on the political agenda. In the first, two privatizations of telecommunications and gas, the industry had, in each case, been sold as a single company. A lot of people thought that privatization had merely turned a public monopoly into a private monopoly, with no obvious improvement in economic efficiency or in social welfare. So when electricity was privatized, there was a real attempt to introduce competition in those sectors of the market where that was possible. Transmission and distribution are obviously natural monopolies. This left generation and retailing, which we also call supply, which sometimes confuses economists.

3. Competition in generation

Of course, the obvious first requirement for competition is that there should be a reasonable number of competitors, and here you might think that the U.K. government missed an opportunity because immediately after privatization, the vast bulk of generating capacity was concentrated in the hands of three companies. I also have to admit that the original intention of the government was to set up rather more generators, but they were frustrated by a series of events that I don't need to go into here.

However, in the longer term, the real indicator of competition is the freedom of entry into a market, and here our generation market is beyond reproach.

The heart of the competitive market is the pool. The rules of this market are simple. First, anyone can become a generator. All you need to do is to get a license, which is freely available, build your power station, and set it up to the technical standards required by the system.

Then you have to join the pool, which, in structure, is basically a cooperative of producers and retailers.

The third rule is that all generators bid their plant into the pool at 10 o'clock every morning. The National Grid Company, which operates the system on behalf of the pool, collects all the bids, estimates demand in each half hour of the following day, schedules plants to meet that forecast at minimum cost and fixes the price in each half hour at the bid price of what economists call the marginal, but what is in plain language the most expensive, generation set running at that time.

Taken together, these arrangements produce a market structure which is as competitive as any disciple of Milton Friedman could wish. All generators compete on level terms every minute of every day, and there are absolutely no barriers to entry.

4. Competition in retailing

The other potentially competitive market is retailing. The structure of the pool should make competition in retailing easy to achieve. In principle, just as anyone can sell electricity into the pool anyone can buy from the pool. Many large users already operate in the pool and there is no reason why, in the future, there should not be competing retailers of electricity, so that, just as with telecommunications in New Zealand or the United States, even domestic consumers will have a choice of supplier. At present, this freedom of choice is available only to consumers with a load of more than 1 MW. However, the

restriction is essentially a political one; that limit falls to 100 kW next year and disappears entirely in 1998.

5. The performance of the new market

That then is a very brief description of why the restructuring took place, and how it took place. There remain two questions. We have stood in the new world for three years now. Does it work? And of course that key questions for this workshop is: would it work anywhere else?

So, does it work in the U.K.? I think the answer is yes, with some qualifications. The first thing to say is that it has worked technically. The lights have stayed on, the plant has been dispatched, in merit (more or less), and the right payments have flowed, at the right times, from retailers to generators. You may think that that is not much to be proud of, but you should not underestimate the technical difficulties in making such a complex market work, and there were plenty of people who said that it wouldn't.

Second, there has been the dramatic effect on operating efficiency, which I mentioned earlier. The effects have, not surprisingly, been most marked in the generating sector, where my company, National Power, and the other two big generators have all seen major gains.

Thirdly, for many consumers, prices have fallen, although the picture is not uniform and it has been obscured by various taxes and subsidies both before and after privatization; and the fourth major benefit has been the transparency that it has brought to the marketplace as I mentioned earlier. For example, there has been a major public debate in the U.K. recently on the future of the British coal industry. Whatever you may think about the outcome, it cannot be denied that the debate focused directly on the issue of an uncompetitive domestic coal industry in a way which would not have been likely under the old arrangements, when subsidies were hidden as contracts between two public sector industries, and the poor old electricity consumer paid the bill.

6. Lessons for other would-be restructurers

You will have gathered by now that I'm something of an enthusiast for the new world, but even I would have to admit that there are still some, how shall I put it, some open questions. But I'll pick those up when I try to answer the question which is the big one for this conference and that is...Is the U.K. system exportable? And if it's not exportable in its full glory. what bits of it are? The centerpiece of the U.K. arrangements is the pool. Only, I think, with the pool or with something very like it can you achieve, first, the delegation of investment decisions to the marketplace and, second, the possibility of real competition in retailing. I have to say I find the first of these more important than the second. In the U.K., the jury is still out on the question of whether the market will do a better job of investment planning than a central planner would have. The record of the old CEGB was not, as I have said, very good in this regard. The last twenty years or so have seen serious overinvestment, caused mostly by over-optimistic forecasts, but also by a wish to keep British plant manufacturers in employment. There were reasonable concerns that the new arrangements would lead to under investment and capacity shortage. In fact, for a variety of reasons which I won't go into, there has been a huge build in gas-fired, combined-cycle gas turbines, and the overcapacity is as bad as ever. This means that the market arrangements for rewarding capacity are essentially untried because the market payment stays resolutely, and rightly, at zero. I have to say I'm not convinced that those arrangements will work very well but I am driven to the conclusion that if you want the market to set the level of investment, then the system we have got is the worst system there is, apart from all the others.

I also have to stay that I think that a competitive pool will work only if the technical conditions are right. In particular, you need a good transmission system. Our commercial arrangements are based on the assumption that our transmission system is perfect. In other words, it assumes that an extra kW of demand anywhere on the system can be met by an extra kW of generation, anywhere on the system. Even for the U.K. system, which is by common consent overengineered, that is something of a

heroic assumption, and much of the dissatisfaction with the pool stems from the rather crude methods used to reconcile the purity of the concept with a rather more untidy reality. If the transmission system is even less perfect, for example, if it is little more than a set of interconnectors between semi-independent systems, then a single pool is likely to fail. Of course, one can still realize many of the benefits of competition in generation with less radical measures, but my own view is that the U.K. system has an impressive logic to it and it works, at least in the U.K.

I am conscious that I have concentrated almost entirely on generation, and to a lesser extent retailing. That is because transmission and distribution are straightforward natural monopolies which are not suitable for a market solution. There are, of course, some large questions about how such network monopolies should be regulated and in particular, how they can be given incentives both to operate efficiently and, what is possibly even more important, to price and invest efficiently.

On these difficult questions I shall say nothing, on the grounds that they have not yet been addressed in the U.K., so we don't have any experience for you, and also because there are people here who are far better qualified than I to tell you what ought to be done.

7. Conclusion

I am a simple generator, and from where I sit, the new world looks all right. There are still rough edges to be smoothed off, but it's an awful lot better than what we had before. Of course, the market prospects in the U.K. are poor, and we in National Power are actively looking to invest in dynamic economies like India, but that is another story.

Levels of competition in the U.S. power sector

by
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1. Levels of competition

One of the most critical issues facing the privatizing government is how far it wants competition to permeate the previously monopolistic structure of the industry. Today, there is broad (though not universal) acceptance that the generation function is potentially competitive. However, there is equally broad acceptance that the transmission function and at least the "wires business" in the distribution function[2] are, in most circumstances, a "natural monopoly."[3] This raises the critical and usually controversial question of where competition should be introduced, and where service should continue to be provided on a monopoly basis.

In most countries today, the distribution function, where the electricity systems interact with the end-use customer, is provided on a monopoly franchise basis.[4] This typically means that the distribution company is granted a franchise service territory with a more or less exclusive monopoly right and accompanying obligation[5] to provide end-use customers with

[1] An earlier version of this paper appeared in Bernard Tenenbaum, Reiner Lock, James V. Barker., "Electricity Privatization: Structural, Competitive and Regulatory Options," Energy Policy, December, 1992. The views expressed in this paper are those of the author and do not necessarily represent the views of the World Bank or the co-authors of the earlier paper.

[2] Transmission is typically distinguished from the "wires business" of distribution on the somewhat arbitrary basis of the voltage level of the transmission of the power. We will refer to the wires and related facilities in both functions as "transmission facilities". Some have argued that competitive joint ventures (a type of joint ownership) in transmission could obtain the benefits of competition in transmission service without losing the efficiencies of a single integrated operation. See Susan Braman, Theory and Application of Competitive Joint Ventures, Ph.D. dissertation, Georgetown University, Washington, D.C., August 1992.

[3] A monopoly is a natural monopoly when production by a single entity is the cheapest way of producing any level of output and production by a single firm is the natural outcome of the market's operation, absent any government intervention. See Richard Schmalensee, The Control of Monopolies, Lexington Books, D.C. Heath Company, 1979, p. 2.

[4] On many systems, this is integrated within a single company structure to provide generation and transmission service on this basis also.

[5] In the U.S., this is often referred to as "the obligation to serve," and in the European Community (EC) as "security of supply."

the service they need. The end-use customers receive a bundled "wires" and power sales service. Generally, the exclusive right to serve is maintained by the utilities' monopoly control over transmission facilities (at least the distribution "wires" and, where integrated companies exist, the entire transmission system). Most customers do not, under this system, have access to other power suppliers because they do not have rights to use the utilities' transmission facilities. Nor in most cases do they have the economic ability or legal right to build their own facilities to do so. Hence, the key to significant competition on most systems comes down to who has "access," or the right to use, the utilities' transmission system on reasonable terms and conditions. Most privatizing governments will have two fundamental options:

1.1 *Wholesale/nonfranchise access*

This would limit competition to the "nonfranchise" level, typically the wholesale level, by allowing only generators and distribution utilities access to the transmission grid in order to give the latter increased options as to power supply.[6] As the high-voltage transmission grid has grown in the U.S., some level of competition in these markets has developed even without major government intervention to guarantee access for these entities to transmission service. This competition has been facilitated by a significant level of voluntary access or "wheeling" granted by utilities, especially as to each other's surplus capacity, and to the development of an "independent" power sector under federal regulatory guarantees that guarantee some market, albeit often localized, for their power.

However, a legal or regulatory requirement that utilities must grant access on reasonable terms to generators to reach distribution utilities is widely viewed as essential to a fully competitive bulk power market in generation.[7] The justification for imposing such a requirement is that a competitive generation market will narrow inter-system operating cost differentials and enhance long-term investment efficiency. It is this fundamental notion that was driving both the European Commission's Directive that would have required "third-party access" (TPA) and legislation recently passed by the U.S. Congress that mandates unbundled "transmission service." Both initiatives are designed to enhance competition in the inter-utility bulk power markets.

The issue of mandatory wholesale access has proved highly controversial in both the EC and U.S. contexts. Those who support it argue that it is the fundamental prerequisite to a fully competitive generation market. Those who oppose it, usually transmission-owning utilities, have argued that the only efficient way to run an electric power system is as an integrated monopoly. They contend that open access and competition threaten both the technical reliability of utility systems and their own long-term economic efficiency and assurance of supply. While the first view has been adopted in the U.S. in the Energy Policy Act of 1992 that was signed into law on October 24, 1992, the debate still goes on in Europe.

1.2 *"Retail" or "franchise" access to end-use customers*

The yet more controversial and difficult issue is whether the competing generators should also have transmission access to end-use (retail) customers; or, to put it in a way that highlights company concerns, whether end-use customers should have the ability through transmission access to reach other suppliers and hence, to escape the hithertofore exclusive supply monopoly.

Added to accentuated concerns about system reliability and long-term efficiency is the fundamental economic concern of distribution suppliers—that a right of end-use (retail) customers to leave their systems at will could lead to serious "stranded investment" problems that could raise prices for remaining customers and even threaten the financial viability of the

[6] Many developing countries such as China, Honduras, and Guatemala have opted for an even more limited form of wholesale competition. In these countries, independent power producers (IPPs) compete for the right to make a long-term power sale to an existing vertically integrated utility with a de facto or legal monopoly in a particular geographic area. This is sometimes referred to as the "central procurement" model. It represents a sanitized, compartmentalized form of competition. It is competition to supply an input rather than competition to take away customers.

[7] The access may be granted to the generator, or to the distribution utility, or, to render the right most usable, to both. The U.S. seems to be moving towards a buyer and seller access regime.

distribution monopoly.[8] The stranded investment concern is particularly acute for vertically integrated systems that have built capital-intensive, long-gestation facilities to meet the expected "load" or demand of franchise customers on a long-term basis. It is also potentially present in the case of a distribution company heavily dependent on long-term take-or-pay power contracts with IPPs. These concerns appear to be accompanied in the U.S. context by a deep-seated and not unreasonable fear of utilities that retail access will undermine the current monopoly franchise system.

In reality, the stranded investment problem may properly be characterized as a "transition" issue[9] inherent in the movement from an exclusive franchise distribution monopoly system to one that permits competition at the end-use level.[10] It can be managed by imposing notice or direct compensation requirements on end-use (or wholesale distribution) customers leaving the franchise system, and on those, having left, wishing to return to the system for assured service.[11] These requirements would be related to the utility planning horizons for additional capacity investments and would be designed to protect the utility from "stranded investment" losses and to protect remaining customers from returning customers' threatening adequacy of service.

An additional problem which must be confronted, even if the stranded investment problem is solved, is the obligation of wheeling customers to other customers that are connected to the grid. Customers that withdraw from a franchise must be required to procure sufficient generating capacity to ensure their security of supply. If such a requirement is not imposed, the new "non-franchise" customers will receive reliability benefits because the franchise customers will pay for generating capacity that protects everyone that is connected to the grid. In other words, a regime that permits customers to purchase energy without any capacity responsibility is unfair to those customers that purchase the capacity that provides emergency protection for everyone connected to the grid.[12] This is an example of a free rider problem.

In the recently concluded U.S. debate over enhancing competition in the electricity sector, the view that ultimately prevailed was that end-use access or retail wheeling should not be endorsed as national policy. In the EC, the proposed Commission Directive on TPA would have required Member States to grant access on all interconnected transmission systems to large end-users (those approximately 25 MW and above) and to distribution utilities who individually or "in association" comprise at least 3 percent of the Member State's overall consumption.[13] In Britain, where the complete vertical deintegration of the industry has reduced political opposition and economic concerns, the right of access is currently available to 1 MW or larger. As noted above, that size limit will be eliminated in 1998; hence, every

[8] In India, the economic incentives for State Electricity Boards (SEBs) to allow retail wheeling are not clear cut. Since most SEBs are currently short of capacity, it would be to their advantage to lose load to another supplier. However, this effect has to be balanced against the fact that industrial customers often subsidize other customers. In another paper prepared for this conference, it was observed that the SEBs generally oppose giving high-tension customers access to the grid because these customers pay their bills and their departure "would make the SEBs dependent on small customers from whom the collection is difficult". Administrative Staff College of India, Commercialization of Power Sector In India.

[9] In a major report by former Commissioner Stalon and the Federal Energy Regulatory Commission (FERC) Staff to the Commission in 1989, it was argued that, during a "transition period," the FERC needed to be "sympathetic" to the "stranded investment" concerns of utilities that supply the power needs of distribution "requirements" utilities (i.e., those that rely on the supplier for all or most of their generation needs). These customers leaving a utility system can cause stranded investment problems similar to end-use customers' leaving. See FERC, "The Transmission Task Force's Report to the Commission. Electricity Transmission: Realities, Theory and Policy Alternatives," October 1989, p. 175.

[10] This principle was applied by the FERC in a decision concerning wholesale service to "requirements" customers (typically supply-dependent distribution utilities). FERC indicated that it would allow "legitimate and verifiable stranded investment costs on a case-by-case basis" in cases where open access was not contemplated when the power supply contract was signed. Energy Services Inc., 58 FERC ¶ 61,234 at 61,770 (1992). FERC decisions are reported in a fashion similar to court decisions by Commerce Clearing House, Inc., a company that reports the decisions of specialized U.S. regulatory agencies. FERC decisions are reported by volume number (here "58 FERC" means the 58th volume of FERC reports). Each case is assigned a number designated by a paragraph sign (here ¶ 61,234), followed where pertinent by a page number (here 61,770), and followed by the year of the decision. All further citations of FERC decisions herein follow this standard citation system.

[11] In the U.S., this is sometimes called the "prodigal son" problem.

[12] This is an example of a "network externality". Loop flow is another example of a network externality. The difference between the contracted power scheduled over an interconnection and the actual physical flow is known as parallel or loop flow in the U.S.

[13] Article 7(2), "Proposal for a Council Directive concerning common rules for the internal market in electricity," Commission of the European Communities, Directorate-General for Energy, Brussels, January 17, 1992.

homeowner in England will, theoretically, be able to shop around for electricity.[14] If the "stranded investment," emergency "free rider", and political problems can be managed, one could envision at least three models for accommodating end-use or retail access in a "steady state" situation:

SIZE LIMITS: This model would permit access for only end-users (or distribution-only utilities) of a certain minimum size, as in the proposed EC Directive. The primary motivation for such a limit is twofold:

- A practical, somewhat paternalistic, recognition that only end-users with the financial incentive to devote adequate resources and capabilities to effectively procure power in a competitive, bulk market, should attempt this quite technical and complex task; and
- A concern that large numbers of end-users or distribution-only utilities seeking access, perhaps without the necessary expertise to procure power effectively, could jeopardize the technical reliability and long-term efficiency of the supplying systems.[15]

NEW LOADS: This model would permit access only for new customers or for incremental loads, i.e., new demand, but would not permit customers access to switch suppliers for existing loads.[16] One problem is that a simple "new customer" requirement could lead to "gaming" of the system, e.g., by an existing corporate customers going out of corporate existence and re-emerging as a "new" corporate customer.[17]

CUSTOMER SELF-SELECTION: This model would permit a customer to select whether it prefers to be served on a monopoly franchise, assured supply basis or to "shop" on the competitive bulk power markets for its own supply. Such a system could permit customers to move from one to the other regime with reasonable notice. The advantage is that, with proper notice, this system reduces the likelihood of stranded investment because it encourages more careful delineation of the rights and responsibilities of the distribution company and the different categories of customer. A variant of this approach was adopted in 1986 by the California Public Utilities Commission (CPUC) for intrastate natural gas transportation service. The key element in the program is a distinction between "core" and "non-core" service.[18] The CPUC initially decided which customers go into each category based on previously determined priorities related to volume of consumption and access to substitute fuels. This type of program could be applied to electricity and modified to allow for self-selection by customers.[19]

2. A phased strategy

As the protracted and often quite emotional debates over transmission access in the U.S. and the EC demonstrate, the issue of introducing any significant level of competition through access is

[14] See Parliamentary Select Committee report, supra, note 28. The Committee questioned whether unlimited end-use access will yield the same benefits as improved metering (combined, presumable, with time-of-use tariffs).

[15] While size limits are inherently arbitrary, they should, at least, be related to reasonable judgements as to these two factors. Moreover, any access proposal keyed to size inevitably raises a "boundary" problem. Customers below the minimum size will have the incentive to group together to get over the size requirement. The electricity regulator in Britain has already had to address this problem.

[16] In the U.S., a form of access for new end-use customers is allowed in the state of Georgia. The four major utilities in the state compete for new industrial and commercial loads above 900 kW if the customer locates its facility outside of a city limit. However, once the customer chooses its supplier, it must remain with this supplier in perpetuity. Therefore, the competition is a one-time competition. See "Georgia Territorial Electric Service Act," (GA. L. 1973, p. 200, par. 1). This competition is made possible by the fact that each of the four utilities has a partial ownership interest in the entire high-voltage grid. Ownership provides transmission rights anywhere on the high-voltage system.

[17] The Georgia law tries to prevent such gaming by tying the service to specified physical facilities.

[18] See CPUC, Decision 91-11-025, November 6, 1991; and Michael F. Russo and David J. Teece, "Natural Gas Distribution in California" in Richard J. Gilbert, ed., Regulatory Choices, University of California Press, Berkeley, California, 1991.

[19] It appears that Portugal has opted for this approach. Industrial customers will be given the choice of participating in the "binding" or "non-binding" market. If they choose to be served in the binding market, the regional distribution company will have a legal obligation to supply them with power on a regulated basis. If they choose to buy in the unregulated non-binding market, they cannot return to the binding market without first giving two years notice to the regional distribution supplier.

controversial. However, there is a growing consensus that, if implemented properly, a transmission access regime that introduces competition in generation at the wholesale or non-franchise level could capture many of the potential benefits of competition without threatening system reliability, security of supply, or the financial health of the industry.

However, the yet more controversial step of also introducing some competition at the level of end-use sales, directly challenging the monopoly status of the local supply franchise, elevates such concerns to a new level. Hence, it requires a careful analysis of both the short- and long-term impacts. The central long-term issue is what such competition would do to the supply planning function of the distribution franchise utility, especially if it retains an "obligation to serve" end-use customers. In many cases, this function will be operating in an industry which requires either capital-intensive long-gestation generation investments of the utility itself, or long-term contractual commitments to other generators. Such an environment, certainly without adequate regulatory safeguards and notice requirements, could lead utilities to plan too little generation in order to minimize economic risk, but with the effect of exacerbating risks to reliability or to security of supply. Alternatively, they may plan generation for load that subsequently leaves its system prematurely and leaves remaining customers (or the utility's shareholders) with the larger cost burden of excessive reserves to bear. Moreover, while customers physically embedded in a utility's system may theoretically buy power from another system through retail wheeling, in reality the power may come from the original supplier, forcing it into a "supplier of last resort" role that may be difficult to avoid (e.g., by cutting off supply) or to be compensated for (e.g., by penalty provisions). Hence, if end-use or retail access is not implemented very carefully and with full regard to its implications, it could lead to planning inefficiencies that, in an industry this capital-intensive and captive to long planning timeframes, could be very costly.

In light of the enormity of the challenge of even introducing effective competition of the generation level, the prudent course for most privatizing governments may be to limit competition, at least in the early years of privatization, to the generation level, i.e., non-franchise access, and not to enter the arena of end-use level competition. This should make management of the economic and technical challenges and risks, and of political opposition to the privatization, immeasurably easier.

Power sector regulation in India, U.K., and U.S.

by
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1. Introduction

Regulation is one of the key factors that must be addressed in the pursuit of power sector reform. Regulatory reform needs to march hand in hand with any sector restructuring and/or introduction of private sector participation. As part of the background for the October 1993 Conference on Power Sector Reforms in India, this paper therefore presents:

- A summary of the existing legal and regulatory environment in which the Indian power sector operates
- A comparison between the regulatory arrangements in India, the U.K., and the U.S.

2. Legal and regulatory environment in India

This section first describes the legal framework that governs the Indian power sector and the main institutions and companies that operate within the power sector. It then summarizes the regulatory structure.

2.1 *Legal framework and institutions*

Electricity is a "concurrent" subject under the Indian Constitution. This means that both the central and state governments have powers to enact legislation affecting the power sector. In general, the central government has taken the lead in defining the main legislation, the 1948 Electricity (Supply) Act (E(S) Act), and in providing the policy framework through the Ministry of Power (MOP). Meanwhile, state governments have focused on specific issues relating to the generation and supply of electricity in their state. States may, and have, amended sections of the E(S) Act as it applies in their own state. In addition, two or more states

can require the central legislature to pursue new laws on their behalf that apply just to the states concerned. If the state and central government legislations were to be in conflict, the central government legislation would prevail; however, this situation has not arisen, and political considerations are such that it is unlikely to do so.

Power sector legislation is embodied in the 1910 Indian Electricity Act (IE Act) and the E(S) Act, together with amendments and regulation issued under these Acts.

The IE Act provided for the issue of licenses to supply electricity and set up procedures to regulate the licensees. Parts of the IE Act were overtaken by the E(S) Act. However, licensees continue to operate under the provisions of the IE Act. There are currently 57 distribution licensees, of which 5 also engage in power generation, although these companies account for only a small proportion of total electricity supply.

The main purpose of the E(S) Act was to create the State Electricity Boards (SEBs). These are statutory organizations responsible for the development of the power sector in their respective states. The Industrial Policy Resolution of 1956 reserved generation and distribution of electricity almost exclusively to the state sector in the form of the SEBs. In the union territories and in a few states in northeastern India, however, power development is the responsibility of the electricity departments or municipal corporations.

The constitution and composition of SEBs, their powers, operations, staffing, and their financial accounting and audit procedures are comprehensively covered in the E(S) Act. The Act also gives powers to the central and state governments in matters such as approval of investments and borrowings and gives wide powers for state governments to issue directives.

A further purpose of the E(S) Act was to create the Central Electricity Authority (CEA), which is administratively responsible to the MOP. Originally a part-time body, the CEA became a full-time organization in 1974. The CEA develops power sector policy and has wide powers which are discussed further below, for example to approve investment projects.

In 1976, the E(S) Act was amended to provide for the establishment of central and state generating companies to augment power availability and to achieve a more efficient utilization of national resources cutting across state boundaries. Under the 1976 amendment, a generating company must be formed by central or state governments (or jointly by a combination of these). Such a company must be registered under the Companies Act, 1956, and must have, among its objects, the establishment, operation, and maintenance of generating stations. Generating companies are to sell power to SEBs and electricity departments as per their allocated shares. The following central generating companies exist: National Thermal Power Corporation, National Hydroelectric Power Corporation, North Eastern Electric Power Corporation, Neyveli Lignite Corporation, and Nuclear Power Corporation.

Some of the state governments have also established power corporations responsible for power generation. However, in most of the states, these corporations construct and commission power plants, which are generally handed over to the respective SEBs upon completion.

In 1991, the relevant parts of the E(S) Act were amended to allow a generating company to be formed in the private sector as well.

Regional Electricity Boards (REBs) were established in 1963 as associations of the constituent SEBs and other power utilities in the respective regions. The REBs are under the administrative control of the CEA. The REBs are charged with the responsibility of coordinating the generating schedules of the power utilities, monitoring system operations, and helping to arrange interstate exchanges of power. However, it was only in 1991 that the statutory powers for effective control were provided to the REBs. According to the amendment of the E(S) Act, in August 1991, every licensee and generating company shall follow all directions of the REBs, including compliance with the instructions of the Regional Load Dispatch Center to ensure integrated regional grid operations.

The Powergrid Corporation of India Ltd. was established in 1989 with a view to formation of a national grid and integrating the grids in the five main regions of India. Powergrid has the legal form of a 'Generating Company' under the provisions of the E(S) Act, although it does not have a direct involvement in generation per se.

Two power sector financial institutions exist, the Rural Electrification Corporation and the Power Finance Corporation. Both are under the administrative control of the MOP.

2.2 *Regulatory structure*

Economic regulation of the Indian power sector is carried out by:

- Central government
- State governments
- CEA
- The SEBs themselves.

Of course, there are a number of other regulatory bodies that control aspects of the power sector, such as the Ministry of Environment and Forests and the Reserve Bank of India; however, these areas of regulation are not covered in this paper. Neither do we cover the substantial policy development role of the MOP, which is not strictly a regulatory role.

The central and state governments have several types of powers which they can use to exercise regulatory control over the SEBs.

Section 78A of the E(S) Act gives the state government the power to issue directives to the SEBs on matters of policy. If there is a dispute over whether a directive relates to a policy matter for this purpose, then the matter can, in theory, be referred to CEA for their decision or it can be challenged in the courts. In practice, where directions have been challenged, the courts have decided in favor of state governments (e.g., over directions on the level of prices to agricultural customers). This gives the state governments wide-ranging and unrestricted general regulatory power. Moreover, state governments can exercise more informal powers, e.g., through its powers to appoint board members of the SEBs, that means that it often need not resort to the issue of directives.

Section 79 of the E(S) Act also empowers the state governments to issue regulations on a specific list of topics, some of which relate to their quasi-ownership role, such as financial reporting and the holding of Board meetings. The list of regulatory powers covers the right to determine the:

- Principles by which the SEBs themselves regulate prices for bulk electricity (grid tariffs) and other aspects of their relationship with licensees; and
- Principles governing the supply of electricity by the SEB to customers.

As for many regulation all over the world, there is also a "catch-all" clause which allows the state government to issue regulation on any other matter arising out of the SEB's functions for which it is "necessary or expedient" for the government to issue regulations.

The CEA is the other main regulatory body. Its regulatory powers include:

- Authorization of all power projects above 25 crore rupees (the power being exercised at several different points through the life-cycle of projects from original inclusion in the Five Year Plan, through to project execution); and
- The resolution of disputes in certain cases (e.g., between state government and SEB, between SEB and REB/Regional Local Dispatch Center over dispatch instructions).

In addition, CEA has wide powers to issue regulations under Section 4C of the Act. Central government can also make rules, via CEA, under Sections 4A and 4B, although these have to be approved by parliament.

The SEBs themselves exercise regulatory powers over the licensees which cover matters such as closure of generation stations and prices, and conditions of supply to other customers. As noted above, these powers are themselves subject to any regulation issued by the state government in this respect.

2.3 *Comparison of Regulation in the U.K., U.S., and India*

The purpose of this section is to present a high-level comparison of the regulatory and legal environments of the U.K., the U.S., and India. The choice of the U.K. and the U.S. as comparators reflects the fact that these two countries represent the dominant, although not the only, examples of transparent regulatory regimes which have been in place for some years.

The main features of the comparison are set out in the following series of tables:

Table 1	Industry structure
Table 2	Legal framework
Table 3	Regulatory institutions and processes
Table 4	Instruments of economic and technical regulation
Table 5	Power sector planning (generation)
Table 6	Power station authorization
Table 7	Price regulation
Table 8	Technical and quality of supply regulation
Table 9	Consumer protection

Table 1
Industry structure

U.K. (E&W)	• Regional distribution companies, national grid company, competing generation companies • Competition in wholesale generation (competitive power pool) and in supply to larger customers (above 100 kW from April 1994)
U.K. (Scotland)	• Vertically integrated regional utilities, with some independent generation contracted on long-term basis • No formal wholesale generation competition, but with competition in supply to larger customers
U.S.	• Vertically integrated regional utilities in each state, together with independent power producers (IPPs) selling bulk generation to some of these utilities; also, many small cooperatives/municipalities undertaking distribution and supply • Increasing competition for construction and operation of new power stations to supply utilities; competition in spot and short-term wholesale generation (inside and outside power pools) and little competition in retail supply (utilities have monopoly franchises over customers)
India	• Vertically integrated regional utilities in each state, together with some national bulk generation; private licensees undertaking some generation and distribution • No competition in generation or supply

Three different power sector regimes exist in the U.K.: in England and Wales (E&W), in Scotland, and in Northern Ireland. Although many of the regulatory features are the same, there are some differences in detail which result from the different industry structures. Where relevant, the Tables comment separately on E&W and Scotland; the Northern Ireland arrangements are less relevant because of the small size of the system and so are not covered in the Tables.

In the U.S., the industry structures and regulatory arrangements differ in detail although not in substance, between the 52 states. The Tables represent the most common arrangements.

We summarize below the main points of comparison that emerge from the description presented in the tables.

Industry structure (Table 1) is an important input to a comparison of regulatory arrangements. In particular, the regulatory arrangements will reflect the nature of ownership and the extent of disaggregation and competition within the electricity sector.

The industry structure in India resembles that of the U.S. (and, to a lesser extent, Scotland); the comparison will strengthen if the development of independent power projects in India takes off so as to give an industry structure in which private generators play an important role in supplying vertically integrated regional monopolies. The major contrast with the U.K. relates to the prominence given to the role of competition in supply and the role of competition in the E&W power pool.

The power sectors in the U.K. and the U.S. are both dominated by private sector companies which are driven by commercial motives. Consequently, explicit independent regulation of these companies is required in both countries. This contrasts with India, where the SEBs are not required to act as commercial entities.

Table 2 summarizes the legal environments in the three countries. There is a distinct contrast: the U.K. system is based around a licensing regime; in the U.S., the evolution of case law in the courts plays a substantial role in defining the legal environment; in India, the emphasis is on supervision of public sector entities by the government administration and is, in some aspects, similar to the old U.K. system before privatization.

There is a clear similarity in the federal/state division that exists in both India and the U.S. However, the central (federal) government in India has played a much stronger role in exercising a central policy framework, largely because of the emphasis on national planning.

Turning to the regulatory institutions and processes (Table 3), there are a number of differences between the U.K. and the U.S. (e.g., sector-specific regulator in the U.K. v. utility-wide Public Utilities Commission (PUC) in the U.S., regulatory discretion in the U.K. v. quasi-judicial approach in the U.S.). However, the U.K. and U.S. systems share a number of common features when contrasted with India. In particular, the regulatory institutions in the U.K. and the U.S. are independent of government (and power sector companies) and operate with

Table 2
Legal framework

U.K.	• 1989 Electricity Act — Sets up licensing framework for generation, transmission, public electricity supply (including both distribution and supply), and competitive supply — Establishes regulatory body [Office of Electricity Regulation (OFFER)] together with its duties and powers • Actions of regulator are subject to judicial review on questions of law or process • General competition law plays a potentially important role
U.S.	• 1920s PUHCA Act provides very broad legal framework for federal regulation of the utilities sector. Individual state laws created regulation structure in each state • Other relevant legislation includes Administrative Procedures Act at federal level which controls the regulatory process and 1992 Energy Policy Act which removes remaining legal barriers for IPPs • Federal legislation can be enacted which affects state utilities (e.g., 1979 PURPA which requires utilities to buy from independent generators at avoided cost and 1991 Clean Air Act which sets up tradeable permits for SO_2 emissions) • State and federal regulators can be challenged in relevant courts • The bulk of the detailed regulatory rules are defined by precedent either in the form of case law or in the form of previous regulatory judgements which have been upheld in the courts
India	• Concurrent sector with powers for both central and state governments to legislate • 1948 E(S) Act establishing SEBs as statutory bodies and setting out powers of SEBs, CEA, and government • Decisions and actions of SEBs and state governments can, in principle, be challenged in the courts

Table 3
Regulatory institutions and processes

U.K.	• OFFER covers sector-specific economic regulation and competition issues • OFFER is independent of government; decisions are made by a Director General who has considerable degree of discretion in reaching these decisions subject to the duties and powers imposed by the 1989 Act • It is becoming common practice for OFFER to issue consultation documents inviting comments from interested parties in advance of important decisions • Department of Trade and Industry retained some powers to issue orders in restricted cases (e.g., emergencies, renewable energy obligations)
U.S.	• PUCs are responsible for regulation at the state level (e.g., pricing, quality of supply); they usually cover all privately owned utilities, not just electricity; municipalities and cooperatives are usually free of direct regulatory oversight • PUCs are run by a group of Commissioners who may be elected or appointed by state government • PUCs hold quasi-judicial hearings at which interested parties present their cases in open sessions • Federal Energy Regulatory Commission (FERC) deals with issues which are not exclusive to each individual state (e.g., transmission and interstate sales of bulk power) • Department of Energy maintains limited policy role
India	• Main regulation powers are split between CEA (e.g., power station development) and state governments (e.g., electricity pricing) • Proposals exist to establish Power Tariff Boards, but little progress to date, and no statutory powers are currently envisaged

a reasonably transparent, rules-based approach; in contrast, the regulating bodies in India are not independent of government or the power sector companies and important aspects of the regulation process are opaque (e.g., price setting).[1]

The contrast in regulatory processes is naturally reflected in the differences between the use of regulatory instruments (Table 4). The U.K. and the U.S. rely on a rules-based approach embodied in a variety of instruments such as licenses, regulatory determinations/judgments

[1] *Electricity Councils were set up to have an independent (but consultative) role; in practice, they have not played their role effectively.*

Table 4
Instruments of economic and technical regulation

U.K.	• Conditions attached to the licenses issues under Electricity Act (together with amendments agreed by regulator and licensee, etc.) • Orders made by Secretary of State for Trade and Industry, in restricted areas under Electricity Act • Determinations made by Director General of OFFER in resolution of disputes • Codes of practice approved by OFFER on technical matters or areas of customer protection
U.S.	• Notices of judgements made by PUCs • Court rulings on matters sent to courts on appeal
India	• Directions issued by state governments under Section 78(A) of the 1948 Act • Notifications issued by regulating bodies (CEA, SEB) under authority of relevant parts of 1948 Act • Note that, to a significant extent, regulation can be exercised through control and approval powers in an informed way

Table 5
Power sector planning (generation)

U.K. (E&W)	• No central planning: new investment is driven by commercial incentives under which generators build new stations either speculatively or contracted under long-term sales agreements to distribution companies or large customers
U.K. (Scotland)	• Vertically integrated companies are subject to a requirement to meet a generation security standard, but it is their decision whether they build new stations themselves or buy bulk generation from third parties
U.S.	• Obligation on regional utilities to meet security of supply standards • Planning of new power station is effectively subject to PUC approval, often in the context of 'Least Cost Planning' in which the economics of capacity additions are compared with demand reduction measures
India	• New power stations are sanctioned within the context of Five Year Plans which cover all public sector investment. Site selection committees and CEA investigate possible power station sites. Schemes are put forward by SEBs for inclusion in the plan. CEA reviews and approves individual schemes as well as the overall investment portfolio, as part of the planning process

and court decisions. In India, most of the regulatory processes involve more informal directions from government to the power companies.

There are marked differences in the role of planning in the development of generation (Table 5). At one end of the spectrum there is no central coordination of planning in E&W where investment in generation reflects commercial decisions. At the other end of the spectrum, there are elaborate arrangements for planning and control of new generation in India. This contrast reflects the different objectives: in E&W the objective is to promote competition in an environment where there is no meaningful obligation to supply in respect of generation; in India, the objective is to mobilize resources to try and keep pace with the needs of rapid expansion. Scotland and the U.S. represent examples between the two ends of the spectrum.

The difference in role of central planning is reflected in the authorization process for generation investment (Table 6). In all countries there are important hurdles that need to be passed on environment impact, local planning requirements, and consultation, etc. (although we do not cover these non-economic aspects of regulation in the table). Once these important hurdles are cleared, authorization/licensing tends to be something of a formality in the U.K. and the U.S. In India, there are several additional authorization steps; this reflects the much greater role of central planning as discussed above.

In a superficial sense, there is explicit price regulation in all the countries (Table 7). In practice, of course, the rate of return criteria for price setting in the E(S) Act is almost universally overridden by political and social considerations. Moreover, the process for seeking authorization for tariff changes in India is not explicit or transparent.

Table 6
Power station authorization

U.K.	• License required from Secretary of State for Trade and Industry (usually a formality) • Sanctioned by board of company as for any other major commercial decision
U.S.	• License required from PUC or other state agency • License issuance does not necessarily guarantee later recovery of associated costs in retail or wholesale prices.
India	• Project must be approved by CEA and Planning Commission for inclusion in Five Year Plan • Technical details must be approved by CEA (and modified according to CEA directions) • Fuel linkage clearance required from Ministries of Coal, and Petroleum and Natural Gas • Final clearance required by Planning Commission (state projects) and by Central Cabinet, via Public Investment Board (for central generating project)

Table 7
Price regulation

U.K. (E&W)	• Price regulation set out in licenses issued to relevant companies • Transmission and distribution prices controlled by formulae that allows average prices to rise at the rate of inflation less some percentage X • Value of X is reset by agreement between the regulation and company every four to five years; if agreement cannot be reached then the matter is referred to the Monopolies and Mergers Commission for a form of adjudication • Generation purchase prices are passed through to franchise customers as generation is procured in a competitive market • Prices to non-franchise customers are unregulated • License conditions restrict cross-subsidies or discrimination between customers
U.K. (Scotland)	• As for E&W except that the generation component of prices to franchise customers is set by a formula which represents bulk generation market value (pass through of generation costs is not permitted because of vertical integration)
U.S.	• Price regulation is implemented by PUC under legal requirement that prices should be 'fair and reasonable'; the definition of 'fair and reasonable' has evolved over time through precedent • Prices are almost exclusively set by rate of return criteria which permits a reasonable return on assets • Recent changes are introducing some 'incentive regulation' (analogous to U.K.) and allow pass through of generation purchases that are incurred from independent generators under competitive tender • Detailed tariff approval by PUC addresses relative prices to different consumer group (mainly on average cost principles) • Price regulation of wholesale power sales by FERC (by mix of cost and market-based approaches)
India	• 1978 amendment to the E(S) Act requires SEBs to earn (at least) a 3 percent return on historic cost asset base • SEBs are empowered to set prices so as to meet this requirement, but this power is subject to state government approval; in practice social and political considerations dominate and the 3 percent return requirement is not met (except for few utilities) • Pricing to different consumer groups is also effectively controlled by state governments; there are no restrictions on cross-subsidization which is extensive

Technical regulation (Table 8) is very similar in format between the three countries which reflects the engineering aspects of the electricity industry. In contrast, there is no explicit customer protection (Table 9) in India.

In conclusion, when looking at the comparison in the attached tables, one can pick out a number of common themes between the U.K. and the U.S. which are in contrast to the regulatory environment in India. These could be summarized as follows:

- In the U.K. and the U.S., there is an emphasis on explicit, independent regulation and transport, even though this is achieved in somewhat differing ways; the emphasis of regulation is on control of price, quality of supply, and consumer protection more than regulation of supply and investment
- In India, the regulatory institutions and high-level rules are defined in legislation, the emphasis of regulation is on control of supply side investment (particularly generation) rather than prices, quality of supply, or consumer protection.

The differences in emphasis reflect a variety of factors which include: the chronic supply situation in India which requires rapid expansion of generating capacity; the contrast in the status of the electricity industry between privately owned, commercial driven companies in the U.K. and the U.S. and the traditional role of public sector statutory bodies which are, in part, a tool of social and political policy in India.

Table 8
Technical and quality of supply regulation

U.K.	• Security of supply criteria set out in standards attached to the licenses • Technical standards on voltage and frequency set out in Grid and Distribution Codes approved by regulator under conditions of the licenses • Quality of supply standards set and monitored by OFFER under provision of the Electricity Act • Technical matters controlled under Regulations issued under Electricity Act (e.g., installations inspection carried out by inspectors appointed by the Secretary of State; meter installation inspections administered by OFFER)
U.S.	• Standard set and monitored by PUCs
India	• Technical regulation, such as voltage and frequency, are set out in Schedule 5 of the Indian Electricity Rules, 1956 and subject to state government approval • No formal regulation of quality or security of supply • Technical matters are regulated by the Central Electrical Inspectorate (set up under 1910 IE Act) under the CEA, and by the state electrical inspectors set up under the 1956 Indian Electricity Rules

Table 9
Consumer protection

U.K.	• Various codes of practice approved by OFFER (e.g., on disconnection for non-payment of bills) • Rights of appeal to OFFER on disputes involving customers and licensees • Consumer Consultation Committees, which are formally a part of OFFER, monitor performance of regional electricity companies • Ad hoc consumer consultation/surveys to inform policy development of licensees/OFFER
U.S.	• Consumer advocate departments located inside or outside state PUC
India	• District consumer forum set up in some states under judge(?) to resolve minor consumer complaints; otherwise no formal consumer protection other than through resorting to the courts • State Electricity Consultative Councils • Local Advisory Committees may be constituted by state government on matters which it may determine (which could include consumer protection issues)

Regulation and management of the power sector in India

by
Tata Energy Research Institute

1. Executive summary

The power sector in India, since independence, has evolved as a public monopoly. Electricity is a concurrent subject in the Indian Constitution, whereby decisionmaking and implementation involves both the central/federal and the state/provincial governments. Traditionally, the policy guidelines and the statutory and organizational framework for power development is provided by the central government, and the state governments are primarily responsible for power generation and supply to the ultimate consumers. The power sector is governed by the Indian Electricity Act, 1910 and Electricity (Supply) Act, 1948 [E(S) Act].

The power sector has undergone a sea of change over the last four decades, both in terms of the number and structure of the institutions and in terms of the structure of consumption. The organizational structure of the power supply industry has followed an evolutionary process to achieve the basic objectives of overall energy and power development policies. The recent change permitting the entry of the private sector in power generation and distribution is a move towards an open market structure. The twin objectives of bringing in the private sector in power generation and distribution relate to additional resources required for power sector development, as well as to bring about improved efficiencies through increased competition.

This paper focuses on the growth, operation, and management of the power sector in the present framework of institutional setup and regulations. It also attempts to highlight some of the important issues critical for the efficient functioning of this sector and discusses some of the measures necessary to improve the performance of the power sector.

1.1 Institutional framework

The institutional structure of the power sector in India comprises:

- State Electricity Boards (SEBs) and Electricity Departments (EDs), statutorily responsible for the efficient and economic development of the power sector in their respective states/union territories.

- Central generating companies which generate and supply power in bulk to the SEBs.
- State power corporations which are mostly involved in construction and commissioning of the power plants. The plants are generally handed over to the Boards on completion.
- Five private generation and distribution companies
- Distribution licensees supplying power in a specified area.

The Ministry of Power (MOP) has the overall responsibility for power development in the country. The MOP is responsible for formulating policies and plans for power development, processing power projects for investment decisions, training and human resource development, research and development, and formulating any legislation pertaining to power generation and supply. The MOP provides the required linkages between other ministries and departments in the central government, state governments, and the Planning Commission (PC). The MOP, in performing all its functions, is guided by the Central Electricity Authority (CEA), a statutory body set up under the provisions of the E(S) Act.

There is often a perceived misconception on the clarity of roles between the MOP and the CEA. The CEA may in fact be considered as the technical wing of the MOP. While the CEA recommends the technical component of a plan and its financial implications, it is the MOP that has the final authority to make a decision.

Power planning and development has been based on a regional approach (the country is divided into five regions, each comprising three or more states) to maximize utilization of unevenly distributed energy resources. The Regional Electricity Boards (REBs) in each region are responsible for coordinating the generating schedules of the power utilities, monitoring system operations, and helping to arrange interstate exchange of power. However, the multiplicity of generation organizations in the region, with each pursuing its own corporate objective, at times conflicting with each other, lead to suboptimal solution in scheduling and regulating generation and at times to wasteful spilling of reservoirs. It is expected that the provision of statutory authority to REBs in 1991, will result in greater grid discipline.

The need for integration of regional grids to form a national grid is becoming increasingly important in order to facilitate transfer of power from a surplus region to a deficit one. The Powergrid Corporation of India Ltd. (PGCIL), established in 1989, aims at forming a national power grid with the objective of facilitating transfer of power within and across regions with reliability, security, and economy, on commercial principles. In the first phase, the PGCIL has taken over construction, operation, and maintenance of power transmission systems of four central generating companies.

1.2 Planning

Power systems planning and optimization studies carried out by the CEA form the basis of the power program. Formulation of the individual projects is carried out by the SEBs. All the projects with costs exceeding Rs. 25 crores are statutorily required to obtain techno-economic clearance from the CEA. In addition to this, all the power projects are required to obtain several other clearances from various ministries and departments of the central and state governments. The final clearance on the project is given by the PC for state sector projects and the central cabinet in case of central sector projects. All the central sector projects require cabinet approval following the approval of the Public Investment Board (PIB).

One of the problems often faced in the entire process of project formulation is the bureaucratic delays in obtaining various clearances. Substantial delays are reported in obtaining environmental clearances. It is important that the CEA and the other ministries/departments involved in the process of providing clearances must streamline their procedures and develop a time-bound program for granting clearances. This however requires adequate preliminary investigation of the project and also requires that the Boards and generating companies prepare correct and complete detailed project reports (DPRs). It must be pointed out that while there are a lot of discussions relating to the delays in procuring clearances etc., the subject of project reports reaching the CEA or the PC with inadequate information, thus also contributing to the delays, goes unmentioned.

The second major weakness of the present system of power planning is lack of coordinated planning of generation and transmission. Generation projects have invariably gained priority over transmission projects. Inadequate investments in the transmission system is the main cause for the increase in the transmission and distribution (T&D) losses and poor quality of

supply in the Boards. There is a tendency to overload existing transmission capacities and earmark the available resources for generation projects. It is important that the generation and transmission planning is done simultaneously and not sequentially, and there should be no bias in allocation of resources between generation and transmission projects.

In the formulation of distribution plans, there are no efforts at systematic planning, not to mention the issue of optimization. Lines are generally extended in a haphazard manner and often with the objective to cover as many villages or areas as possible, without any regard to the capacity of the system to sustain the load. The ad hoc expansion of the distribution systems has resulted in high losses, low reliability, and frequent interruptions.

There exists substantial potential to improve the performance of the distribution systems through efficient operation and management of the existing systems and through a more scientific system planning for the future load growth.

The planning for the power sector in the past has been based on the traditional approach of meeting demand through new capacity additions. The increasing shortage of resources and the need to limit environmental impacts of power generation, distribution, and utilization calls for a thorough evaluation of all available options to meet the demand. This includes meeting the demand for electricity through demand-side management (DSM) options. Increasing energy efficiency and conservation has proved to be more cost effective in many developed and developing countries, as compared to supply options. The planning for the power sector, in the future, must therefore integrate both supply and demand side options to develop a least cost plan.

1.3 Finances

Financial planning of the power sector is governed by the Annual Plans and the budgetary mechanism. Once a project is included in the Plan, there is a virtual guarantee to cover the costs irrespective of any time or cost overruns that it may undergo. However, there is considerable uncertainty regarding the amount of funds that would actually be made available to the power projects during the different years of the Plan. The declining financial health of the state governments adversely affects the availability of funds for the projects. Often the actual disbursement of funds is adjusted for the interest and electricity duty due to the state governments by the Boards. Also, due to the poor liquidity position of the Boards, the capital resources are diverted for working capital expenditure. All this results in substantial delays in completion of the projects and consequent cost overruns.

The capital structure of the SEBs is primarily debt-based. This poses heavy interest burden on the Boards and thus increases the cost of power generation and supply. There are significant delays in adjusting tariffs to reflect the increase in cost of generation and supply, resulting in huge financial losses for the Boards. Most of the SEBs have negative internal resource generation. The present capital structure of the Boards is not sustainable and the financial viability of the Boards is crucial for its growth and development. In order to partly offset high interest costs, some of the state governments have converted a part of their loans into equity. The full impact of this measure is yet to be perceived. At least 20 percent of the capital expenditure should be financed by the Board's internal resource generation. This requires rationalized tariffs, cost control, and complete financial discipline in the operations of the Boards.

1.4 Tariffs

The average revenue realized being less than the average cost of generation and supply is perhaps the single most important reason for the deteriorating financial health of the SEBs. Tariffs are guided more by social and political considerations of the state governments rather than economic and efficiency objectives. All the Boards recognize the excessive political interference by the state governments in setting tariffs as against their advisory role laid down in the E(S) Act. Tariffs for the agriculture sector are the most influenced with the extent of subsidies (difference between average cost of supply and average revenue) being as high as 80-100 percent in various states.

There is an urgent need to bring in transparency in the tariff revision exercises. Tariffs in the short run should be based on normative efficient cost approach and move towards marginal costs in the long run. All the electricity sales must be metered and flat rate tariffs must be abolished. While it is justified to provide electricity at affordable (even subsidized) rates to the weaker sections of the society, cross-subsidization should be limited to within consumer categories. Establishment of the National Power Tariff Board at the center with five

Regional Tariff Boards conceived by the central government, is a right move in the direction to bring in autonomy as well as accountability in the operations of the Boards.

1.5 Management and operation of the SEBs

The role of the state governments as the owner of the SEBs has resulted in their excessive interference in the day-to-day operations and management of the Boards. As per the E(S) Act, the board members are appointed by the state government. The Boards are required to constitute State Electricity Consultative Councils (SECCs) to advise the SEBs on questions of policies and to review the progress and planning of the SEBs. These councils are expected to meet once in three months. However, it is reported that SECCs have not, in the past, been effective in overseeing the operations and management of the Boards, as envisaged in the Act.

As long as the Boards are totally owned by the government, the board members will continue to be appointed by the governments. Even if the Boards are converted into corporations, but still wholly owned by the government, there will be no change in the situation regarding the appointment of the Board members.

There exists substantial scope for improvement in the operations of the Boards. Some of the important areas are:

- Improving generation efficiencies of the existing facilities such as increasing plant load factor (PLF) and plant availability, reducing specific fuel consumption, reducing auxiliary consumption, etc.
- Reducing T&D losses through optimal T&D planning, adequate investments, and effective measures to curb theft of power.
- Rational utilization of the excess staff with the objective to improve the manpower utilization efficiencies. This requires enhancing the skills of the personnel in case of redeployment.
- Introducing innovative options to ensure accurate metering, timely billing, and regular collections.
- Reducing revenue outstandings through greater control and autonomy to take actions against the defaulters.
- Improving the reliability and quality of power supply.

Rapid increase in the size of the Boards, several external factors (such as deteriorating quality of coal received at the power stations), and excessive interference by the state governments are, to an extent, responsible for the present state of affairs in the Boards. The Boards are caught in several day-to-day operational problems such as power interruptions, coal receipt, maintenance of key equipment, billing and collection problems, etc. They have been rather myopic, addressing these problems on a short-term basis rather than finding long-term solutions. What is required is a professional approach with a view to:

- Prioritizing key problem areas
- Finding long-term solutions
- Drawing up a resource plan linked to targets
- Identifying sources of support
- Time-bound implementation and monitoring

It is important to ensure that the incentives are linked to an overall performance score instead of being based on only PLF or losses as at present. This could be done by identifying key performance parameters, giving each performance criteria a weightage, and arriving at a net performance score for the operational unit.

The concept of signing Memoranda of Understanding (MOUs) in the central public sector undertakings should be extended to the SEBs as well. The MOUs distinctly identify the responsibilities and tasks of the governing ministry and the undertaking. Hence, it is expected that the MOUs will result in little or no interference in the functioning of these undertakings.

There are continuing discussions relating to commercialization of the Boards. The suggestions include:

- Converting the Boards into corporations
- Separation of generation, transmission, and distribution functions
- Privatization of distribution
- Rural electrification (RE) to be separated from the Boards operations and converted into cooperatives
- Prices for electricity generation to be fixed by market forces rather than regulation
- Statutory regulatory body for overseeing the T&D operations.

The power sector in India has only recently moved towards privatization in power generation and distribution. While several proposals have been received by the private investors in the area of power generation, no proposal has come forth in the area of distribution. The private investors have been pressing for certain guarantees regarding fuel supply, sale of power, payment for power sold, etc.; thus wanting to operate in a protected environment as against a purely market-oriented environment.

In light of the fact that most of the private proposals are in the process of getting the necessary clearances and finalizing power purchase agreements, it is unlikely that any significant contribution will come in from the private sector even in the Ninth Plan.

Electricity has become a basic necessity for modern living. The state governments have often implemented their social policies through the SEBs (low prices for agriculture, flat rate for very low consumption domestic consumers, etc.). These policies have had an adverse effect on the financial viability of the Boards. On subjects such as disconnection, larger issues beyond the purview of the Boards have constrained their performing on a purely commercial basis. Thus, it is important for the state and central governments, Boards, and other associated organizations to come up with a workable mechanism to enable the Boards to function on commercial terms. In view of the growing size of the power sector, there is an urgent need to bring in transparency in its operations. There is an even more urgent need to identify workable mechanisms to insulate the Boards from interference by the state government in carrying out their functions. One of the ways this could be achieved is through setting up of a high-powered independent regulatory body looking into the functioning of the power sector. The ultimate objective to be achieved in this process is an efficient power sector delivering reliable and quality power in adequate quantities to the consumers at the lowest cost. This must be simultaneously accompanied by ensuring a reasonable return to the producers and distributors of electricity.

2. Institutional framework

Electricity is a concurrent subject in Article 246 of the Indian Constitution, relating to "subject matter of laws made by Parliament and by the Legislatures of the State." Accordingly, the decision making and implementation involves both the central/federal and the state/provincial governments. Traditionally, the central government is responsible for providing the policy guidelines and the statutory and organizational framework for power development, and the state governments are primarily responsible for power generation and supply to the ultimate consumers. The organizational structure of the power supply industry has followed an evolutionary process to achieve the basic objectives of overall energy and power development policies.

Prior to independence, the supply of electricity in India was a predominantly commercial venture undertaken by privately owned utilities located in and around urban areas. The Indian Electricity Act 1910 (IE Act) provided for the issue of licenses, regulated the industry, and protected consumers' interests. At the time of independence, in view of the importance of power in economic development, the need to nationalize and restructure the entire power industry was felt. Consequently, a separate comprehensive legislation outside the purview of the IE Act was conceived to provide for the state-owned organizational structure.

2.1 *State-owned organizational structure of the power industry*

The SEBs, created as a result of the Section 5 of the E(S) Act, are statutory organizations responsible for the efficient and economic development of the power sector in their respective states. The Industrial Policy Resolution of 1956 reserved generation and distribution of electricity almost exclusively to the state and this led to the gradual nationalization of the power supply industry.

In the union territories and some states in northeastern India, power development is the responsibility of the EDs or the municipal corporations. The constitution and composition of SEBs, their powers, operations, staffing, and their financial accounts and audit procedures are comprehensively covered in the E(S) Act. The

E(S) Act, Section 18
The state electricity boards shall be charged with ... "to supply electricity... in the most efficient and economical manner with particular reference to those areas which are not for the time being supplied or adequately supplied with electricity."

provisions have been modified, from time to time, to meet the necessary requirements arising out of the rapid growth of the power sector.

At present, there are 18 SEBs, 13 state/union territory EDs, and 1 municipal corporation in the 25 states and 7 union territories in India. In several states, licensees already engaged in generation and distribution of power were allowed to continue their operations so long as their licenses were valid. There are 57 distribution licensees operating in the country today, and 5 of these are also engaged in power generation.

Section 78(A) of the E(S) Act provides for the state governments to give directions, if necessary, on matters of policy to guide the functioning of the Boards. While the section clearly mentions that guidance is to be given on the subject of policy, the issue of what constitutes policy has been left open for interpretation. There have been a couple of cases where, for instance, the court has held that it is within the law for the state government to direct the Board to charge a flat rate for agricultural pumping and it does fall within the purview of what constitutes policy. In practice, it is also observed that the directions from the state government are not only limited to matters of policy but also in operations.

2.2 *Generating companies*

In 1976, the E(S) Act was amended to provide for the establishment of central and state generating companies, with the objective to supplement the efforts of the SEBs to augment power availability and with a view to achieve more efficient utilization of national resources cutting across state boundaries.

"Generating company" is defined as a company formed (a) either by the central government or any state government, or (b) jointly by the central government and one or more state government or by two or more state governments. Such a company must be registered under the Companies Act, 1956 and must have among its objects the establishment, operation, and maintenance of generating stations. Generating companies are to sell power to SEBs and EDs as per their allocated shares.

E(S) Act, Section 78(A)
"In the discharge of its functions, the Board shall be guided by such directions on questions of policy as may be given to it by the state government."

"If any dispute arises between the Board and the state government, as to whether a question is or is not a question of policy, it shall be referred to the Authority, whose decision shall be final."

E(S) Act, Section 79
"The Board may, by notification in the Official Gazette, make regulations...on issues...administration of funds, maintenance of accounts, grid tariffs.... The regulation for the administration of funds, matters relating to Section 20 and spending funds not covered under Section 61 and 62 shall be made only with approval of state government. Regulations relating to grid tariffs and arrangements of licensees would be made with the permission of CEA."

The following are some corporations presently functioning as central generating companies:

- National Thermal Power Corporation
- National Hydroelectric Power Corporation
- North Eastern Electric Power Corporation
- Neyveli Lignite Corporation
- Nuclear Power Corporation (NPC)[1]

Some of the state governments have also established power corporations responsible for power generation. However, in most of the states, these corporations construct and commission power plants, which, on completion, may be handed over to the respective SEBs. Such corporations include:

- Orissa Power Generation Corporation
- Uttar Pradesh Rajya Vidyut Utpadan Nigam Ltd.
- Karnataka Power Corporation
- West Bengal Power Development Corporation.

[1] The NPC maintains and operates nuclear power plants and supplies power in bulk to the SEBs, and is under the jurisdiction of the Department of Atomic Energy.

To accelerate hydroelectric development, the central government has also established special joint corporations with some of the state governments, such as Naptha Jhakri in Himachal Pradesh, Tehri in Uttar Pradesh, etc.

As per the recent amendment of the E(S) Act in 1991, a generating company can now be formed either in the public sector, in the private sector, or in the joint sector.

2.3 *Ministry of Power and Central Electricity Authority*

The MOP has the overall responsibility for power development in the country. The MOP is responsible for formulating policy and plans for power development, processing power projects for investment decisions, training and human resource development, research and development, and formulating any legislation pertaining to power generation and supply. The MOP is responsible for the administration of the IE Act and the E(S) Act and for introducing amendments as necessary, conforming to the government's policy objectives. The MOP provides the required linkages between other ministries/departments in the central governments, state governments, and the PC.

The MOP is guided by the CEA, a statutory body set up under the provisions of the E(S) Act. The CEA was set up as a part-time body in 1951 under the Central Water and Power Commission and was converted into a full-time body only in 1974. The responsibilities of the CEA include:

- To develop a sound, adequate, and uniform national power policy
- Formulate short-term and perspective plans for power development
- Coordinate the activities of the planning agencies in relation to the control and utilization of power resources
- Act as arbitrators in matters arising between the SEBs and the consumers
- Promote the integration of the state's power systems and provide technical assistance to the power utilities
- Promote and assist in the timely completion of schemes sanctioned and to monitor their implementation.

The CEA has four field organizations for carrying out periodical assessment of future load demands. The CEA also provides the secretariat for CEB and the organization for the Central Electrical Inspectorate (these are statutory institutions under the IE Act).

The central sector power corporations, the central research organization—Central Power Research Institute, the central manpower training organization—Power Engineers Training Society, and two financial organizations—Rural Electrification Corporation (REC) and Power Finance Corporation (PFC) are all under the administrative control of the MOP.

There is a perceived misconception on the clarity of roles between the MOP and the CEA. The CEA is considered as the technical wing of the MOP. All the generation and transmission projects need a statutory techno-economic clearance by the CEA. In formulating policies, the MOP seeks the advice of the CEA on issues relating to policy, operations, training, etc., for the power sector. The MOP implements these policies through the various power sector organizations in association with the CEA. Thus, while the CEA recommends the technical component of a plan and its financial implications, it is the MOP that has the final authority to make a decision.

2.4 *Regional integration*

Uneven distribution of the coal and hydroelectric resources across the states and the limitations of the states as spatial units for planning power development, promoted the regional approach for power development. Thus, in 1963, the country was divided into five regions comprising three or more states in each region. REBs, as associations of the constituent SEBs and other power utilities in the respective regions, were created through central government resolutions and are under the administrative control of the CEA.

The REBs are charged with the responsibility of coordinating the generating schedules of the power utilities, monitoring system operations, and helping to arrange the interstate exchange of power. However, the multiplicity of generation organizations in the region, with each pursuing its own corporate objective, at times conflicting with each other, leads to suboptimal solution in scheduling and regulating generation and at times, to wasteful spilling of reservoirs. It was only in 1991 that the statutory powers for effective control were provided to the REBs.

According to the amendment of the E(S) Act in August 1991, every licensee and generating company shall follow all the directions of the

REBs and shall conduct their operations in accordance with the instructions of the Regional Load Dispatch Center (RLDC) to ensure integrated regional grid operations.

> **E(S) Act, Section 55**
> "Every licensee shall comply with such reasonable directions as the Board may from time to time, give him for the purpose of achieving the maximum of economy and efficiency in the operation of his undertaking or any part thereof."
>
> "Every licensee or generating company shall follow all the directions of the REBs...to ensure integrated grid operations."

In the event of any dispute arising in the directions given by the REBs, the matter is referred to the CEA, whose decision is regarded as final. However, in the larger interest of integrated grid operations, the licensee or the generating company is bound by the directions of the REBs, until the decision is given by the CEA.

2.5 *National grid*

PGCIL was established in 1989, with a view to formation of a national grid and integrating the grids in the five regions. The main objective is to facilitate transfer of power within and across regions with reliability, security, and economy, on commercial principles. PGCIL is to undertake the following responsibilities in a phased manner:

- Phase I: to take over completed, operational, and ongoing EHV and HVDC transmission projects under the central sector generating companies
- Phase II: to take over the operations of the RLDCs with the objective to improve coordination of the regional grids
- Phase III: to pool power from central generating companies and sell it to different beneficiary states in the region ensuring that all the states get their due shares. Surplus power from SEBs and the other utilities is also proposed to be pooled.

Adequate interregional ties and appropriate commercial arrangements, if in place, can reduce the energy shortages by making the power available in the surplus regions to the deficit ones. In 1991/92, 8.80 Bus of energy was backed down due to non-availability of required interregional linkages.

2.6 *Power sector financial institutions*

There are two financial institutions, the REC and the PFC, specially set up to provide financial assistance for the development of the power sector. Both these institutions are under the administrative control of the MOP.

The PFC, set up in 1986 by the central government, assists high priority power projects by insulating them from the budgetary constraints of the central and the state governments. The PFC provides long-term finance to the SEBs and state power generating corporations for system improvement schemes, renovation and modernization projects, and for accelerated completion of priority generation projects. Funds provided by the PFC are in addition to the annual plans approved by the PC. During 1990/91, the PFC approved loans for a total of Rs. 1,359 crores, of which 44 percent was for thermal power projects and 28 percent for T&D systems. The balance went towards renovation and modernization of thermal power projects, uprating of hydro projects, system improvement, etc. PFC, while providing the loans, lays a great stress on improving the performance of the Boards through the formulation of "Operational and Financial Action Plans" (OFAPs). As at the end of June 1991, OFAPs were formulated for six Boards. It is reported that the Boards have benefitted by implementing the measures outlined in the OFAPs.

The REC was set up in 1969 for promoting RE by financing RE schemes and RE cooperatives. RE programs undertaken by the REC cover electrification of villages, energization of pumpsets, provision of power for small and agro-based industries, lighting of rural households, and street lighting. The REC also provides assistance to the SEBs for taking up system improvement projects for strengthening the sub-transmission systems and improved reliability of power supply. The REC has played a key role in assisting the Boards in spreading the reach of electricity to the rural and remote areas in the states.

The institutional structure of the power sector is shown in Annex 1.

2.7 *Privatization of the power sector*

In September 1990, the Ministry of Energy announced a policy decision of allowing private sector participation in power generation and distribution with the basic objective to bring in additionality of resources for investment in the power sector. Further, private sector participation is expected to bring in increased efficiency in the operations of the power sector.

A policy package comprising financial, commercial, and legal aspects has been put together by the Government of India to provide incentives to the private entrepreneurs to invest in the power sector. The Investment Promotion Cell in the MOP has been set up to directly interface with prospective private enterprise entrants to the electricity sector and help them in obtaining clearances. A high-powered Board has been formed under the Chairmanship of the Cabinet Secretary to the Government of India, to monitor the clearance of the projects.

Several MOUs have been signed by the SEBs with the private investors. Presently, in most of the cases, the private investors are engaged in obtaining the necessary clearances, discussions with the SEBs on power purchase agreements, etc. Actual project construction work is yet to start. It is therefore highly unlikely that there would be any benefits from the private sector in the Eighth Five Year Plan (FYP). Even though the policy of privatization includes power distribution, no proposals have been offered by the Boards to the private sector.

The major concerns of the private investors relate to:

- Delays in obtaining the necessary clearances
- Guarantees for off-take of all power generated
- Guarantees for payments for power purchase
- Assurances for quality and quantity for fuel supply.

The concept of single window clearance, to facilitate fast clearance of the projects for the power investors, is reported to have not met its objectives. It is important for the government to simplify and streamline the clearance procedures to minimize the time spent in obtaining the clearances and work out a definite time frame for project clearance. In the first instance, the SEBs should offer those projects to the private investors which have already obtained most of the clearances required but the work is not initiated for want of resources. The private investors have been pressing for certain guarantees regarding fuel supply, sale of power, payment for power sold, etc.; thus wanting to operate in a protected environment as against a purely market-oriented environment.

Some of the highlights of the government policy are:

- Debt equity ratio of 4:1
- Increase in prescribed rate of return from the existing 3 percent above the Reserve Bank of India (RBI) to 5 percent above the RBI rate
- Period of initial validity of license increased to 30 years from existing 20 years and subsequent extension for 20 years on each occasion
- Capitalization of interest during construction at the actual cost instead of at present 1 percent above the RBI rate
- Exemption of private licensees from obtaining clearances under the MRTP Act
- Up to 100 percent foreign equity participation permitted for projects set up by foreign private investors
- With the approval of the government, import of equipment for power projects will also be permitted in cases where foreign supplier(s) or agency(ies) extend concessional credit.

3. Power planning

3.1 *Long-term planning*

The central planning process in India involves formulation of FYPs. The PC is primarily responsible for the central planning function and is assisted by all the economic ministries/departments and organizations of the central and state governments and UT administrations. The draft plans have to be placed before the National Development Council which comprises the Prime Minister as the Chairman, Members of the PC, Cabinet Ministers, Chief Ministers of the states, and heads of the administration in the UTs.

The formulation of the power program is based on the long-term planning studies carried out by the CEA in association with the SEBs and the generating companies. The CEA prepares a National Power Plan based on the results of the power system planning and optimization studies.

Among the power generation and transmission schemes identified in the optimization studies, the approvals for inclusion in the plans are done by the PC. The PC forms a Working Group for each FYP to draw strategies to identify the priority areas and detailed programs to be included in the central, state, and UT Plans.

3.2 *Project formulation*

Formulation of individual projects is carried out by SEBs and other generating companies. Surveys and investigations for locations of the prospective sites are carried out by the SEBs and the operating companies. Site selection committees are also set up by the government from time to time to identify sites, keeping in view the various requirements for power development. For instance, so far, two site selection committees have been set up (1982/83 and 1989/90), to identify sites for super thermal power stations. Similarly hydroelectric potential studies, carried out by the CEA, identify some of the attractive sites for hydroelectric development.

For all the power projects where the costs exceed Rs. 25 crores, a statutory techno-economic clearance is required from the CEA before the project can be implemented. The CEA, in its regulatory role, is required to ensure the optimality of the project from both short- and long-term perspectives. In addition, the CEA is also required to ensure the economic viability of the projects. In case of hydro projects, the CEA is further required to ensure that the proposed project does not prejudice the other potential uses of water such as irrigation, flood control, navigation, etc. All multipurpose river water schemes are first appraised by the Central Water Commission.

Apart from the techno-economic clearance from the CEA, the SEBs are statutorily required to obtain several other clearances from various ministries and departments of the central and state governments. Environment and forest clearances are to be obtained from the Ministry of Environment and Forests, pollution clearance from state/central pollution control boards, etc. Some of the non-statutory clearances include availability of land and water, fuel linkage, transportation of fuel, and finances. Details of various clearances required for power projects are given in Annex 2.

The final clearance on the project is given by the PC for state sector projects and the central cabinet in the case of central government projects. All central sector projects require cabinet approval following the approval of the PIB.

E(S) Act, Section 28

"The Board or the generating company may prepare one or more schemes...and where the scheme is of the nature referred to in Section 29(1), the scheme shall not be sanctioned by the Board or the generating company except with the previous concurrence of the Authority."

Every scheme sanctioned under this Section shall be published in the Official Gazette and in such local newspapers...as may be considered necessary.

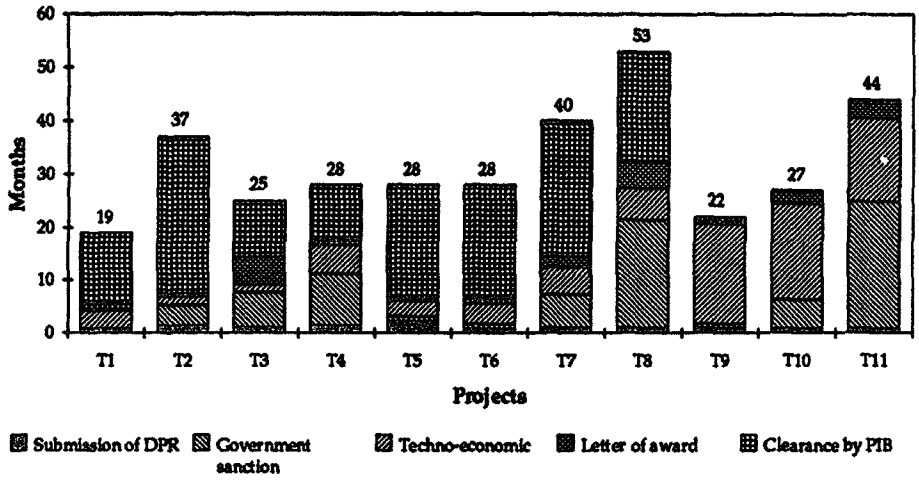
E(S) Act Section 29

"Before finalization of any scheme...and the submission thereof to the Authority...the Board or the Generating Company...shall cause such scheme...with estimates of capital expenditure, salient features, benefits that may accrue...in the Official Gazette and in such local newspapers... along with a notice of the date, not being less than two months after the date of such publication, before which licensees and other

One of the problems often faced in the entire process of project formulation is the long delays in obtaining various clearances. As is evident from a sample of projects in Figure 1, the time taken for generation projects to get the final sanction varied between 17 to 53 months, from the date of submission of the DPR. While the SEBs hold the CEA and the various ministries/departments involved in the process of providing clearances, responsible for delays, the latter have identified poor project formulation, inadequate preliminary investigation, and incomplete information in DPRs as the main causes for the delays in providing clearances. Obtaining environmental clearance is today a major issue in the entire planning process. Large hydro projects have of late attracted the attention of the environmental groups who have (rightly or wrongly) taken the issue of environmental damage of large hydro projects beyond proportions. This is perhaps one of the important reasons for declining hydro-thermal capacity mix in the country.

It is important that the CEA and the other ministries/departments involved in the process of providing clearances must streamline their procedures and develop a time bound program for granting clearances. This, however, requires adequate preliminary investigation of the project

Figure 1
Time taken for obtaining various clearances



T1 - sample thermal project H1 - sample hydro project

and correctly completed DPRs on the part of the Boards and generating companies.

Generation and transmission planning is presently not carried out in an integrated manner. Project implementation delays result in a mismatch in project commissioning schedules between the generation projects and the associated transmission lines. There is a tendency to overload available transmission capacities and earmark the available resources for new generation resources. This is the major cause of the present imbalance between generation and transmission projects.

Distribution planning is carried out by the SEBs. Discussions with the officials of the Boards reveal that expansion of the distribution systems is carried out in an ad hoc manner. Often, the SEBs do not have access to the software that will enable them to carry out a scientific analysis of the options available.

The high priority given to RE has resulted in a haphazard growth of rural distribution systems. The ad hoc expansion of the distribution systems has resulted in high losses, low reliability, and frequent interruptions. There exists substantial potential to improve the performance of the distribution systems through efficient operation and management of the existing systems and through a more scientific system planning for the future load growth.

Power sector development in the past has been based on the traditional approach of meeting demand through new capacity additions. Resource constraints and growing concerns to limit environmental damage owing to production and utilization that necessitates the utilities to adopt DSM options. DSM, which encompasses both end-use efficiency improvement and electricity conservation, has proved to be more cost effective in many developed and developing countries, as compared to supply options. In the future, planning for the power sector should be based on 'Integrated Resource Planning' (IRP) approach. IRP looks at the demand and supply side options in an integrated manner to work out a least cost plan.

4. Finances for power sector development

4.1 Integration of finances in the FYPs

Financial planning of the power sector organizations is governed by the Annual Plans and the budgetary mechanism. The physical plans of the SEBs are translated into financial plans in consultation with the state and central finance ministries, the PC, and the planning organizations at the state level. Over the years, due to the importance of power development for economic development and its capital intensive nature, the share of outlay for the power sector in the total

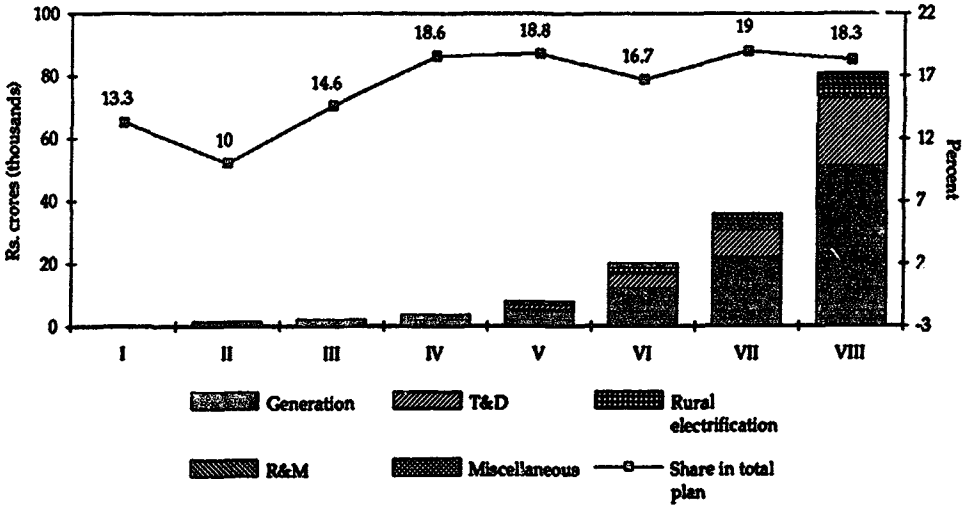
plan outlay has increased from 13 percent in the First FYP to 18 percent in the Eighth Plan (Figure 2).

Once a project is included in the Plan, there is a virtual guarantee to cover the costs irrespective of any time or cost overruns that it may suffer. However, there is considerable uncertainty regarding the amount of funds that would actually be made available to the power projects during the different years of the Plan. Thus, the year-wise allocation of funds made at the beginning of the Plan period is quite tentative and gets modified in every Annual Plan. This non-availability of assured funds affects the ability of the project authorities to effectively plan and control expenditure. In order to circumvent this problem, the SEBs try to include many new schemes in each plan period by perhaps underestimating their investment costs. The idea is that once the project is included in the plan, it would get resources, whatever the escalations in costs and delays in commissioning. This results in spreading rather thinly the limited resources available over many projects. Hence, further delays and cost escalations occur.

There are a large number of transactions between the state government and the Board on various heads of accounts. Some of them are interest due to the state government, electricity duty, revenue subsidy due to the Board, capital receipts, etc. There is often an adjustment across the capital and revenue accounts (as permitted under the E(S) Act, in consultation with the state government), leading to a reduction in the capital receipts from the state government and also diversion of resources from the Boards' capital expenditure to revenue operations. It is reported that, on an average, the actual disbursement of funds in any year by the state government is only 80 percent of the targeted plan allocation. This results in a reduction in capital available for projects and hence, the consequent delays in project commissioning schedules and, as mentioned above, cost overruns. During the Seventh FYP (1985-86 to 1989-90), as against the plan allocation of Rs. 22,784 crores for the state utilities, the actual expenditure was only Rs. 20,757 crores. Details of time and cost overruns for a sample of hydro and thermal projects are given in Figures 3 and 4 (refer to Annexes 3 and 4 for details). Apart from the paucity of funds and inadequate cash flow, some of the other reasons for cost and time overruns include:

- Inadequate project planning and management
- Delays in land acquisition and taking up infrastructural and enabling works
- Tardiness in placing orders for generating equipment and in award of contracts for civil works/erection of equipment
- Delayed deliveries and non-sequential supplies
- Contract failures, court cases, labor problems, law and order problems, etc.

Figure 2
Investments in the power sector



4.2 *Capital structure of the SEBs*

The SEBs are governed by the provisions of the E(S) Act for their financial operations. Traditional sources of capital financing for SEBs comprise state government loans, loans from financial institutions such as Life Insurance Corporation, Industrial Development Bank of India, General Insurance Company, REC, etc., open market borrowing, internally generated resources, and external borrowing via central assistance. State government loans are linked through the state annual plans and budgets. The borrowing from FIs and markets are governed by the PC and the state governments, and are fully guaranteed by the state governments. External aid for the projects is routed through the central government to state governments as a part of the plan resources. The SEBs have been recently permitted to get funds directly from the multilateral funding institutions. However, this has to be within the overall borrowing capability of the Government of India.

The E(S) Act of 1948 did not provide any specific provision for capital structure for the SEBs. A Committee set up by the PC in 1962, recommended an equity-based capital structure on a debt-equity ratio of 1:1. The Venkatraman

Figure 3
Time and cost overruns in commissioning of thermal projects

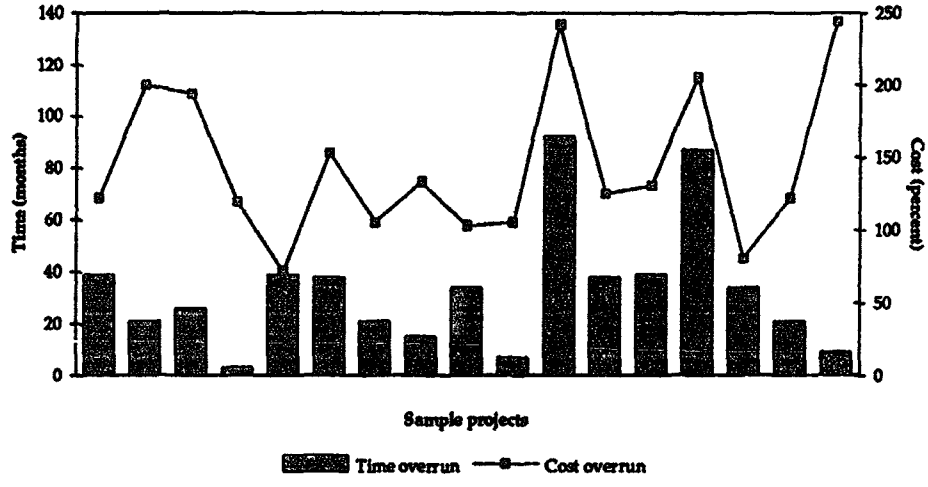
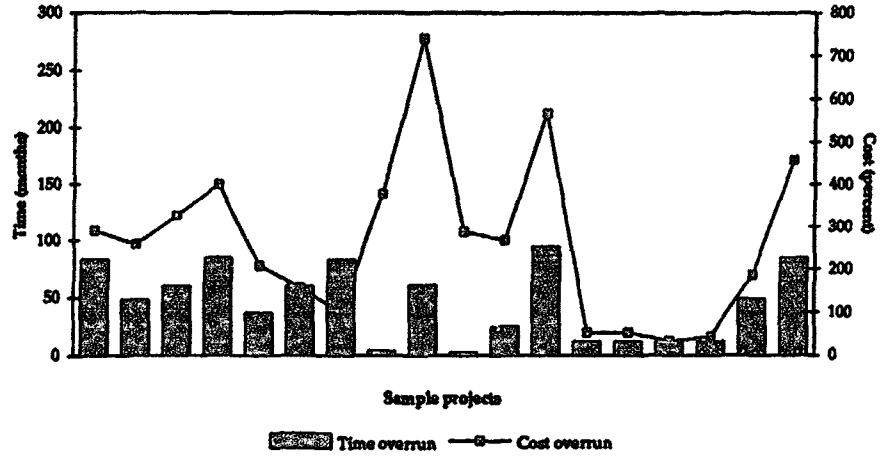


Figure 4
Time and cost overruns in commissioning of hydro projects



Committee in 1964, made another attempt to look into the issue of capital structure, and did not favor the equity-based capital. The main argument being that the interest on loan being a charge is allowed before computation of taxable income while dividend on equity is an appropriation of profit and is subject to payment of taxes. The Committee recommended that the loans by state government under Section 64 should be perpetual. Despite the fact that no such provision is made in the Act, most of the state governments have acted upon this recommendation.

It was only in 1978, that the central government made a specific provision of equity for the SEBs by incorporating Section 12-A and 66-A in the E(S) Act. According to Section 12-A "the state government can declare SEBs as a corporate body with such capital not exceeding Rs. 10 crores but which can be increased with the approval of the State Legislature to the extent the government may deem fit, but not exceeding the aggregate of outstanding loans of the Board." Section 66-A provides for the conversion of the existing amounts of loans into equity.

The existing capital structure of the SEBs continues to be primarily debt-based. So far, only in 4 out of 18 SEBs, state government loans have been converted into equity - Haryana State Electricity Board Rs. 390 crores, Punjab State Electricity Board Rs. 600 crores, Rajasthan State Electricity Board Rs. 600 crores and Assam State Electricity Board Rs. 800 crores. In all the other utilities, the only equity available is reserves, surplus, consumers' contribution towards cost of capital assets, and grants and subventions from the state government towards cost of capital assets. Further, the share of state government loans, which are the main source of finance for the SEBs, has been declining in several states due to the deteriorating resource position of the respective state governments. Consequently, the Boards have resorted to borrowing from the market and the financial institutions, the share of which has increased from 29 percent in 1985-86 to 43 percent in 1990-91, resulting in a substantial increase in interest burden (refer to Figure 5).

Sources of finance for power projects for SEBs

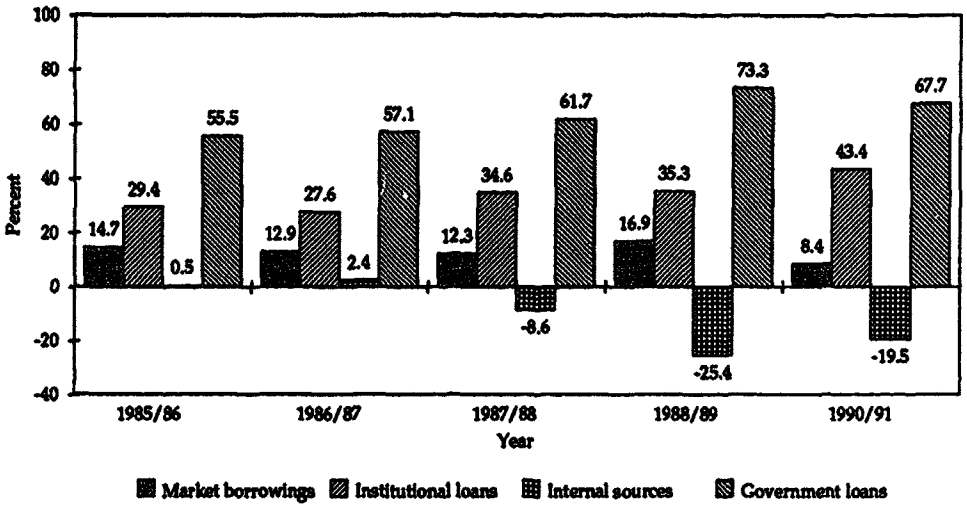
1. Borrowing
   - Domestic
     - Government loans
     - Loans from financial institutions
     - Market borrowing
   - External
     - Loan from bilateral and multi-lateral financial institutions
2. Internal resource generation
   - Retained earnings
   - Consumers contribution
   - Capital grant and subsidies
   - Depreciation
3. Own funds
   - Equity
   - Reserve funds

Negative internal resource generation of the Boards is the fundamental problem for the power sector development. In 1992-93, the estimated net internal resources generated by all the SEBs was Rs. -2,251 crores. The rate of return and depreciation rates have a direct bearing on the extent of internal resource generation. As per the E(S) Act, the SEBs are expected to, after meeting all their expense obligations and after taking into account subventions from the state government, earn a surplus equal to 3 percent of the value of the net fixed assets as at the beginning of the financial year. The state governments can fix a higher rate of return as against the 3 percent specified. However, it must be mentioned that, as of date, no state government has specified a higher percentage of surplus. In 1992-93 the rate of return was -13.5 percent for all the SEBs and the total losses were Rs. 5,130 crores. The reasons for negative rate of return are:

- Tariffs not related to cost of supply
- Low operational efficiencies, low PLF, high T&D losses, etc., resulting in higher per unit cost of generation and supply
- Heavy interest burden due to the present capital structure of the SEBs, resulting high costs
- Large revenue outstandings affecting the liquidity of the Boards
- Partial and delayed payment of revenue subsidies from the state government.

As per the E(S) Act, the Boards charge depreciation on a straight line basis on 90 percent of the value of the asset. The Act also provides for the CEA to revise the rate for depreciation. In the past, the average depreciation rate was of the order of 3.3 percent. Depreciation rates have been raised upward only recently in March 1992 and, if fully provided for at these revised rates, would mean an assured source of funds for the

Figure 5
Capital structure of SEBs



Boards. However, increase in depreciation rates would have to be followed by an increase in tariffs, in the absence of which the Boards will continue to incur losses. This surely emphasizes the need for tariff rationalization by the Boards.

Internal resources should finance at least 20 percent of the total capital expenditure in any year. This requires rationalized tariffs, cost control, and complete financial discipline in the operations of the Boards.

5. Tariffs

The E(S) Act vests the responsibility of setting tariffs for different consumer categories with the SEBs. The tariffs are to be based on the considerations contained in Section 49 and 59 of the E(S) Act. Under the E(S) Act, the Board is to carry on its operations, as far as practical without incurring losses and the Board could, from time to time, adjust tariffs to earn a 3 percent rate of return on net fixed assets as at the beginning of the financial year. Also, in accordance with the Section 78-A, the state government can give guidance to the SEB in setting tariffs.

Pricing of electricity by the SEBs is generally based on the average cost approach. While setting tariffs for different consumer categories, SEBs have to take into consideration the policies and the social objectives of their state governments. Often, the tariffs are guided more by social and political considerations rather than financial or efficiency objectives. The Boards have reported excessive interference of the state government in setting tariffs as against their advisory role.

Tariff revisions by the SEBs are generally carried out on an ad hoc basis. The sole criterion is the absorbing capacity of the consumers without agitation. The additional costs to be recovered are calculated first. Based on this, the extent to which rates for high-tension (HT) consumers can be raised is decided. The balance cost to be recovered is then adjusted to the

E(S) Act Section 49(1)
"...the Board may supply electricity to any person not being a licensee upon such terms and conditions as the Board thinks fit and for purposes of such supply frame uniform tariffs."

E(S) Act Section 49(2)
"In fixing tariffs, the board shall have regard to...the coordinated development of the supply and distribution of electricity within the State in the most efficient and mechanical manner, with particular reference to such development in areas not for the time being served or adequately served by the licensee."

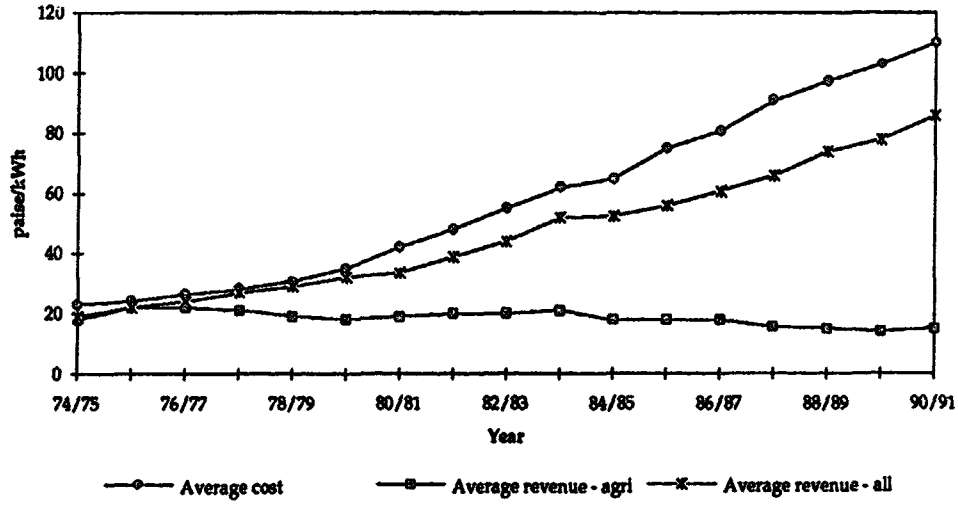
extent possible from the low-tension (LT) industrial, commercial, and domestic consumers. The tariff for agricultural consumers is reported to have a strong linkage to political considerations. The existing tariff structures are characterized by:

- The fact that the Boards are not able to completely recover the subsidies given to some consumer categories through higher rates for other categories (cross-subsidization) and hence the Boards incur losses in their operations. In 1991-92, only two Boards were able to recover their average cost of generation and supply, and in nine Boards the average revenue realized was subsidized more than 25 percent of the average cost (Annexure 6).
- The average revenue realized in most of the SEBs is less than the average cost of supply. The gap between the average revenue and average cost of supply has increased from 3.70 paise/kWh in 1974-75 to 8.67 paise/kWh in 1980-81 and further to 24.70 paise in 1990-91 (Figure 6).
- Agricultural consumers are charged a "flat-rate" tariff based on the connected load (HP of pumpset). Electricity prices are lowest for the agriculture sector and, over the years, the gap between the cost of generation and supply and the average realization from the agriculture sector has increased from 4 paise/kWh to 100 paise/kWh during the period 1974/75 to 1990/91 (Figure 6).
- The State Electricity Duty, as a proportion of average per unit revenue from sale of power, varied between 2 percent and 16 percent in 1990-91 (Annexure 6).
- SEBs have a fuel adjustment charge in their tariffs. This is mostly passed on selectively to some consumer categories, primarily HT consumers and LT industry categories.

The widening gap between the average revenue and average cost of supply has resulted in mounting losses for the Boards. As of March 31, 1992, the total commercial loss of the Boards was Rs. 5,130 crores. Losses incurred by the Boards on account of supplying electricity at a subsidized rate to agriculture consumers are to be subsidized by the state governments. The state governments are to subsidize to the extent that enables the Boards to declare a 3 percent surplus or the full subsidy to cover the loss incurred by the Board in supplying power to agriculture sector, whichever is lower. It is reported that the SEBs have received only about 50-60 percent of the subsidies claimed by them and the total outstandings as of March 1990 are estimated to be Rs. 6,299 crores. There is often a disagreement between the Board and the state government on the quantum and method of calculating the subsidy. Nonpayment or partial payment after substantial delays seriously affects the financial performance of the Boards.

Revising tariffs is perhaps one area where the state governments wish to have maximum influence. The general argument against tariff

Figure 6
Average cost of supply and average revenue realized



increases is that the Boards pass on their inefficiencies to the consumers. The tariffs must therefore be based on a normative efficient cost approach. This calls for an open approach to tariff making where the consumers are informed on the various increases in costs outside the control of the Boards. Also, the consumers must be informed of the efforts being made by the Board to increase efficiency.

Considering the capital intensive nature of the power sector and the fact that the power sector in India is at the increasing part of the cost curve, there is a strong case for adopting the long run marginal cost (LRMC) approach for setting tariffs. As the situation stands, LRMC tariffs will be substantially higher than the present level of tariffs for most LT consumers. For the HT consumers, LRMC tariffs are likely to be either equal or lower than the present level of tariffs. A comparison of LRMC tariffs and the average revenue realized for different consumer categories for one of the utilities is given in Figure 7.

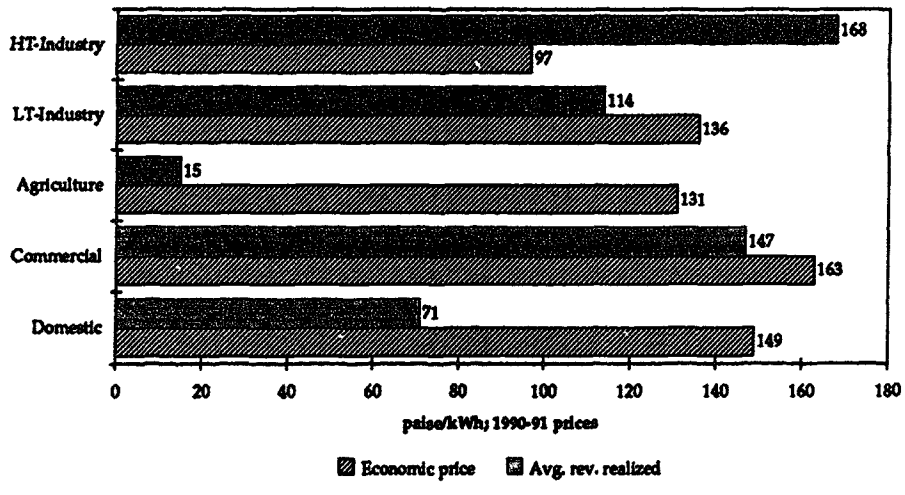
Some guidelines that the Boards could adopt in setting tariffs are:

- Cross subsidization to be within consumer groups rather than across consumer groups
- All electricity sales to be based on metered supply
- Tariffs should encourage efficient use of electricity
- Subsidies where necessary, there should be a mechanism to ensure that they reach the target population
- Innovative tariff options such as time-of-day tariffs to be effectively used for load management.

One of the key suggestions made at the Power Minister's Conference in 1991, in the direction of rationalizing electricity tariffs and reducing the control of state governments in fixing tariffs, was to set up independent expert bodies to analyze costs incurred by the Boards and to recommend tariffs. This was to be done through the establishment of the National Power Tariff Board at the center with five Regional Power Tariff Boards. The constitution of these Boards has been delayed since the corpus fund which was to come from the Boards has not been forthcoming. Some of the SEBs have now agreed to make a contribution to the corpus and it is expected that others will soon follow. Presently, these Boards do not have statutory status and hence, it will be difficult to enforce their decisions.

With the opening of power generation to the private sector, it is expected that generation prices could be set in a competitive framework, provided there were a sufficient number of private generators. In the case of T&D, prices would need to be regulated through an appropriate framework. However, as mentioned above,

Figure 7
Comparison of LRMC based tariffs and average revenue realized



For Maharashtra State Electricity Board

considering the progress in the proposals of the private sector, this is not likely to happen in the next 5- to 7-year time frame. On the issue of privatizing distribution, while the policy framework exists, no proposal has come forth from the private sector. What has been received is perhaps an expression of interest from some private parties, and that too for urban distribution. Except for the four private utilities, the private sector has no experience in the management and operation of the distribution systems. There are indications of Indian firms planning to tie up with U.S., Canadian, and European utilities to bring in their experience. It is too early to come to any conclusion on this subject.

E(S) Act, Section 5

..."The Board shall consist of not less than three and not more than seven members appointed by the state government."

E(S) Act Section 8

The Chairman and other members of the Board shall hold office for such period, and shall be eligible for reappointment under such conditions as may be prescribed.

E(S) Act, Section 10(5)

If the Board fails to carry out its functions, or refuses or fails to follow the directions issued by the state governments, under this Act, the state government may remove the Chairman and the Members of the Board and appoint a Chairman and Members in their places.

6. Operational and management issues in the Boards

6.1 Organizational structure of the Board

Section 18 of the E(S) Act charges the SEBs to supply electricity in the most efficient and economical manner with particular reference to those areas where there is a need for supplying electricity. Section 15 of the Act also gives powers to the Boards to appoint staff required for their operations. Section 79 of the Act gives powers to the Boards to formulate regulations for their different spheres of operation.

The organizational structure of the Boards is generally along the following lines:

- The Board consists of a full-time Chairman and three or four full-time Members each having full and complete responsibility for their own areas. The areas allocated are generally (a) finance, (b) generation, (c) transmission and/or distribution, and (d) projects. The allocation for the members varies across the Boards. The Board has a full-time Secretary, whose appointment is to be made with the approval of the state government.
  It must be noted that, as per the E(S) Act, the board members are (a) appointed by the state government and (b) a specific term for the chairman and members of the Board is not defined.
- The Boards may have separate cadres for generation, transmission, distribution, and financial operations.
- Every power station is headed by either a Chief Engineer or General Manager who is completely responsible for the technical and financial performance of the power stations under their charge. Similarly, T&D circles or zones are again headed by a Chief Engineer and they are responsible for the operations in their circles or zones.
- The chief engineers in turn have a number of superintending, executive engineers, assistant and junior engineers, and other staff to assist them in carrying out their responsibilities.
- The designations for finance officials is different from the operations staff. They may include Chief Accounts Officer, or Deputy CAO, etc.
- The administration is generally under the Secretary of the Board, who has a team of joint and deputy secretaries to assist him in his duties.
- The Boards have a vigilance cell for checking both internal malpractice as well as for looking into matters relating to theft of electricity, which is either under the Secretary or the Chairman of the Board.

The organization chart for one SEB is given in Annexure 7.

6.2 Electricity councils and advisory committees

The SECC is constituted under Section 16, of the E(S) Act, with the objective to advise the SEB on questions of policy and to review the progress

and planning of the SEBs. The Council comprises the Chairman of the SEB as the ex-officio chairman of the council and the members include all full-time members of the SEB, representatives of generating companies in the state, and at least eight members representing the interest of local self-government, electricity supply industry, commerce, industry, transport, agriculture, electricity staff, and consumers of electricity. The council is expected to meet every three months. However, these meetings, as revealed from the discussions with officials in various SEBs, are more of formalities rather than a forum to effectively oversee the operations and management of the Boards.

Under Section 16(6), the Board is statutorily required to place their annual financial statement and supplementary statements if any, before the SECC, and take into consideration any comments made on such statements by the Council before submitting the same to the state government.

Section 17 of the E(S) Act also necessitates that the state government may from time to time constitute Local Advisory Committees (LACs). The Board may consult the LAC concerning any business coming before it and shall also place such business as the state government may, by special order, specify.

Chapter II of the IE Rules, 1956, provides for the appointment of state electrical inspectors and their duties and authority.

6.3 *Staff recruitment*

Staff recruitment for the Boards is generally through a common admissions test, which was, until recently, held every year, for recruitment at the level of the Assistant Engineer (AE) for engineering staff. There was no criteria for the selection of staff for finance and financial operations. The clerical staff were promoted and given some training, while the heads of departments were usually on deputation from one of the other services or even from other organizations such as banks, railways, etc. It is only recently that the Boards have defined requirements for their financial cadres and attempts are being made to train them to effectively perform their responsibilities.

Most of the SEBs are today faced with the problem of overstaffing. Manpower utilization in Indian utilities is quite inefficient; ratio of employees/MW, sales per employee, and number of consumers per employee are high compared to other developed and developing countries. Also, there is a wide variation in these indicators across the Boards (refer to Annexure 8). It is reported that more SEBs are becoming aware of this problem of increased burden of manpower and thus, there has been no major recruitment drive in most of the Boards for the last two to three years. The Boards need to rationally utilize excess staff with the objective to improve manpower utilization efficiencies. This requires enhancing the skills of personnel in case of redeployment.

6.4 *Performance evaluation and human resource development*

Discussions with the Chief Engineers in various Boards reveal that there is ample scope for performance improvement in generation, T&D, and also the fact that there is enough authority and powers vested in the Chief Engineers in order to enable them to function effectively. While the Boards do have rules and regulations to ensure that the employees perform efficiently, it is often the lengthy and difficult procedures that make it difficult to initiate any proceedings against employees who do not perform satisfactorily. There is the opportunity to record the performance of the employee during the annual performance evaluation (known as CRs or Confidential Reports). Any adverse comments have to be intimated to the employee within a given time frame and an opportunity is given to record his views. Also, there is the provision of giving the next higher officer the opportunity to review the case and make a decision on the adverse comments made. There is a process of a series of warnings, letters, charge sheets, etc. to be given to the nonperforming employee, before any action can be initiated. There have been occasions where Boards have taken action against nonperforming employees. However, such cases are few and it is generally in cases of criminal negligence or corruption or bribery, that the action is taken against the employee.

Regarding linking performance to promotions, the official policy is based on seniority-cum-merit. But considering the large number of eligible candidates for middle and senior management (such as Assistant Engineer (AE)) to Executive Engineer (EE), or EE to Superintending Engineer (SE)), seniority gets a higher consideration. In the case of the appointment of the chairman, again the issue of seniority gets importance, although there are several instances where junior members have superseded their seniors. In the Boards, where the chairman is a

nontechnical person, drawn from one of the central services, this issue is not relevant.

The issue of promotions and human resource development in the SEBs has also been a matter of concern. Engineers who join at the AE level, get their promotions after perhaps ten years or more, and there are EEs who have served for 25 years or more and there is little hope for them to possibly move more than the level of a SE, perhaps at the end of their career. There is substantial disenchantment among the SEB staff in this regard. Apart from job rotations, which to an extent means transfers, the issue of human resource development in SEBs is yet to receive the attention that it deserves, particularly considering the impact that these measures can have on improving the performance of the Board's operations.

6.5 *Incentives for efficient operations*

There is ample scope for improving the performance of power stations, transmission, and distribution operations in the Boards. On the generation front, PLF, coal consumption, secondary oil consumption, auxiliary consumption, outages, etc., are some of the parameters in which station performance is measured. T&D losses, breakdowns, supply interruptions, etc., are some of the important parameters for measuring the performance of the T&D systems.

The generation staff have financial incentives linked to the level of generation. Also, the central government has an award scheme for maximum generation by a power station as well as for auxiliaries and for secondary oil consumption. There are both advantages and disadvantages to the scheme for linking incentives to generation. The advantage is that the staff is exhorted to generate more, for this would increase their own financial returns. The disadvantage is that there is not enough attention paid to maintenance and efficiency. The emphasis is on units generated and not on generating efficiently. The question of cost criteria is perhaps not of major relevance, since funds availability is in any case restricted. Also, this has, on several occasions, resulted in generating stations not following instructions from the RLDCs to back down generation during low load periods.[2]

The T&D losses in the Boards are high (all-India losses for 1991-92 are 23 percent) and need to be reduced. One of the major problems is that the figure of the T&D losses is notional since a large block of consumption is estimated based on sample surveys carried out by the Boards. There is an immediate need to put into effect an energy accounting system at the circle or zone level to enable the Boards to estimate T&D losses accurately. The T&D staff did not have any form of incentive which was available to the generation staff. Recently, the Government of India has put in place an award scheme for reducing T&D losses and this financial award has generally been shared equally by all the T&D staff. In several cases, the Boards have complimented this award by putting in an additional amount equivalent to the award from its own budget.

It is necessary to explore some options through which non-generation staff also have financial incentives linked to their performance. This could be done by identifying key performance parameters, giving each performance criteria a weightage, and arriving at a net performance score for the circle or a district as the case may be. The monetary incentive could be linked to the performance in each of the circles. The incentive could be limited perhaps to those circles which perform above average on the total weighted score.

6.6 *Fuel supply*

Power stations have linkages with coal mines from where they are supposed to get their coal. The linkage specifies the quantity of coal, coal quality, and ash content. The Boards and the coal companies carry out joint sampling and weighting to determine the coal quantities and coal quality. When the coal quality deteriorates, there is little choice for the Boards but to change their source of supply. The linkage does not provide for any penalties for deviating from the quality of coal that the coal companies are expected to supply. It is only recently that TNEB has decided to import coal and one would have to wait and see the impact of this decision on the coal companies and the other Boards. The power stations should be allowed to enter into medium- or long-term contracts for the purchase of fuel with suppliers and the prices should be decided mutually. This is expected to bring in timely and quality supply of fuel to the

[2] With the REBs being given statutory authority, this situation is likely to be under control.

generating stations. This issue becomes important in view of the entry of private companies in power generation.

6.7 *Metering, billing, and collection (MBC)*

One of the key factors in the efficient financial performance of the Board is proper metering, timely and correct billing, and the prompt collection of dues.

Accuracy and reliability of the meters are crucial to the billing system. Slow or defective meters result in underestimation of electricity sales and thereby revenue loss to the Board. Also, electricity not measured is often regarded as electricity lost and thus does not give a correct estimation of T&D losses in the system. The Indian Electricity Rules of 1956, Section 46, provides for periodical inspection and testing of consumers' installation at intervals not exceeding five years. However, inspection and testing of HT consumers is carried out at more frequent intervals in order to ensure that there is no loss of revenue due to faulty metering. All Boards have meter testing laboratories for testing and calibrating meters. The Boards are further required to ensure that the meters conform to Indian standards (BIS), or where no specifications exist, the accuracy levels maintained should be 3 percent above or below absolute accuracy levels (Indian Electricity Rules of 1956, Section 57). For LT consumers, meter reading is undertaken by the meter reading section of the distribution circle of the Board. For HT consumers, depending on the voltage of supply and contract demand, the appropriate authority for confirming the meter reading is either an Assistant, Executive, or Superintending Engineer as the case may be.

Billing in its wider definition includes meter reading, bill preparation, bill distribution, and revenue collection. Each distribution circle or zone is responsible of this entire range of activities in their area. There is no uniform system of MBC, across the Boards and across consumer categories in terms of the frequency of billing, bill preparation (manual, computerized), distribution of bills, etc. There is substantial scope for reducing the cost of various operations in MBC in the Boards. There is a need to look into some innovative options for improving the efficiency of MBC activities.

Revenue arrears as a proportion of revenue receipts of the SEBs have increased over the years. As of March 1992, revenue outstandings were 33.4 percent of the total revenue receipts or about four months of revenue. In 4 out of 13 SEBs, these were more than 50 percent and in Bihar State Electricity Board revenue outstandings were significantly high at 94.5 percent (refer to Annexure 9). A large proportion of these outstandings are due from the central/state government undertakings/departments, over which the SEBs can exercise no control. At the state level, these are also mostly water supply, sewerage Boards, street lighting, etc., which, if disconnected, have serious repercussions. Though the SEBs have the power to disconnect any consumer defaulting in the payment of the amount due from him within a specified time limit, this is rarely done by the Boards. In case of HT industrial consumers, it is the larger considerations such as law and order, employment, etc., which generally constrain the Boards from disconnecting the consumers. For domestic and agriculture consumers, it is the social considerations that perhaps prevail. All these considerations constrain the Boards to operate on a purely commercial basis. Greater autonomy needs to be given to SEBs to take action against consumers with large outstandings, including the facility to disconnect power supply. There are several court cases relating to tariffs and billing that have blocked substantial amounts due to the Board. It is important to work out a mechanism by which at least a part of these funds can be released for the Board's operations. The SEBs also need to set up special tribunals to expedite the settlement of disputes.

Boards need to consider some innovative option for MBC activities with a view to reduce the cost of metering and billing and to enable the timely collection of outstandings. This is one area where the Boards could subcontract some or all of the MBC activities to the private sector. However, it is most crucial that there are adequate safeguards to ensure that the existing system leakages do not prevail in the new setup.

6.8 *Theft of energy*

The SEBs have special cells for carrying out inspections to identify cases where electricity is used illegally, without acquiring the permission to do so. These cells carry out surprise checks on consumers' premises and in rural areas to check the HP of pumpsets. The SEBs are to a great extent also dependent on support from the local police, the district magistrate, etc., in carrying out these duties. Cases are registered

when thefts are detected, but it is reported that there still exist procedural problems in processing these cases. Suggestions such as having mobile courts, or even special electricity courts have been made to resolve some of these issues, but these steps still have to get under way.

6.9 Quality of supply

The quality of supply is regulated by the Fifth Schedule of the IE Rules, 1956. The range for low and medium voltages is ±6 percent, for high voltage +6 percent and -9 percent, and for extra high voltage +10 percent and -12.5 percent. The frequency variations allowed are ±3 percent. It is observed that during the daytime and more during the evening hours, the frequency drops and the Boards resort to load shedding. The frequency is generally higher than the limits during the night hours, and this indicates that stations are not willing to back down. With statutory powers being given to the REBs, this situation is expected to improve in the future, for over frequency periods. However, during the periods of under frequency, the Boards would continue to resort to load shedding either manually or through under frequency relays. There is thus a need to evaluate other options for load management, such as DSM, or perhaps through innovative tariff options.

7. Issues and options

The installed capacity in the power sector in India will continue to double at present rates for the next two to three decades. There is substantial scope for improving efficiencies in generation, transmission, and distribution, as well as in project implementation. The present legal framework provides enough powers to the SEBs to draw up regulations, to manage its funds, and to carry out their operations in an efficient and economical manner. Discussions with power sector professionals reveal that it is entirely within the Boards' purview to draw plans for improved performance and implement them. There is perhaps a need for building adequate enforcement mechanisms which will ensure that the SEBs function efficiently. There is also a very strong need to insulate the Boards from interferences by the state government in their day-to-day operations, and limit the guidance of the state government to policy matters as envisaged in the E(S) Act.

As discussed in this paper, there exists substantial scope for improvements in the operations of the Boards. Some of the important areas are:

- Improve the performance of generating stations
- Reduce T&D losses
- Effective measures to curb theft of power
- Rational utilization of the excess manpower
- Introduce innovative options to ensure accurate metering, timely billing, and regular collections
- Reduce revenue outstandings
- Improve the reliability and quality of power supply.

Financial viability of the Boards' operations are of utmost importance. In this connection, it is necessary to ensure that tariffs reflect efficient costs and also that tariffs keep up with increases in costs outside the purview of the Boards. There is excessive political interference in tariff setting (as against the advisory role of the state governments as envisaged in the E(S) Act), and the need for an autonomous body to set tariffs has never been more strongly felt. This is also expected to bring in the necessary transparency in the operations of the Boards.

There are continuing discussions relating to commercialization of the Boards. The suggestions include:

- Converting the Boards into corporations
- Separation of generation, transmission, and distribution functions
- Privatization of distribution
- RE to be separated from the Boards operations and converted into cooperatives
- Prices for electricity generation to be fixed by market forces rather than regulation
- Statutory regulatory body for overseeing the transmission and distribution operations.

Any change should not be considered just for the sake of making a change. The case in point is to convert the SEBs into corporations. This change will bring about no significant benefit unless this is accompanied by real autonomy for these corporations.

The private sector is expected to play an increasing role in the Indian power sector. A beginning has been made with power generation and distribution. While several proposals have

been received in the area of power generation, there has been no interest shown by the private sector in coming into the area of distribution. It would certainly be worthwhile to learn from the experiences of some of the other developed and developing countries who have gone in for privatization in the power sector.

Electricity has become a basic necessity for modern living. The state governments have often implemented their social policies through the SEBs (low prices for agriculture, flat rate for very low consumption domestic consumers, etc.). These policies have had an adverse effect on the financial viability of the Boards. On subjects such as disconnection, larger issues beyond the purview of the Boards have constrained their performing on a purely commercial basis. What is required is to come up with implementable solutions to some of the pressing issues that constrain the Boards from functioning commercially. Any change in the legal and regulatory framework should be undertaken keeping this in view.

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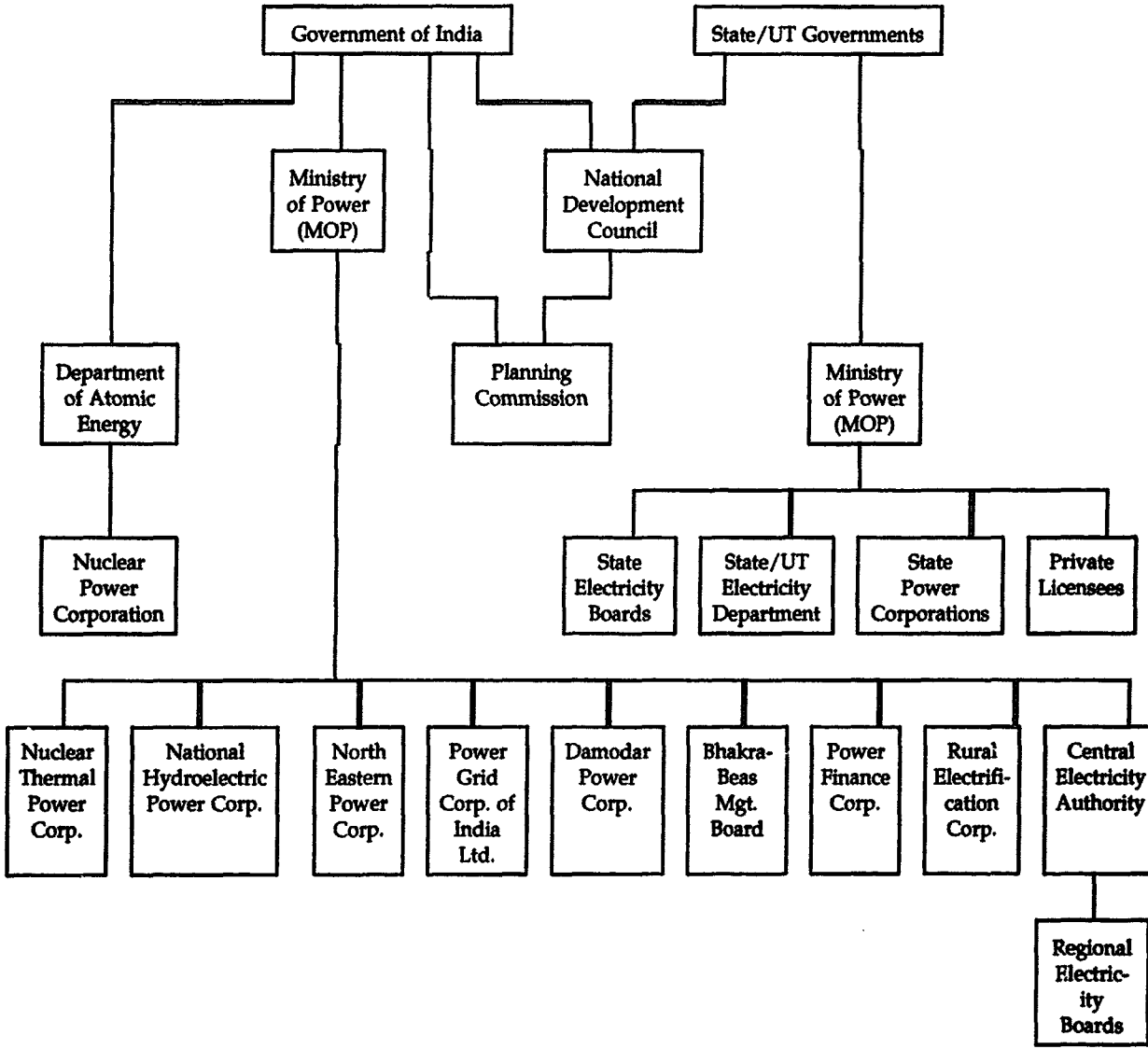
Annex 1
Institutional structure of the power sector in India



Annex 2
List of the main clearances required for investment project processing

Statutory clearances	*Clearing authority*
Cost estimates section 29(1)	CEA
Techno-economic clearance	CEA
Publication/Section 29(2)	State government
Water availability	CWC/State government
SEB clearance	SEB/State government
Pollution clearance	CPCB
Forest clearance	MOE&F/State government
Environment & forest clearance	MOE&F/State government
Civil aviation clearance for chimney height	National Airport Authority
Company registration	Registrar of Companies
Rehabilitation & resettlement of displaced families by land acquisition	MOE&F/State government
Hydel projects	Ministry of Water Resources
Equipment procurement	DGTD, CCI&E

Non-statutory clearances	*Clearing authority*
Land availability	State government
Fuel linkage	Department of Coal, Department of Petroleum & Natural Gas
Financing	CEA/DOP/Department of Economic Affairs/Financial Institutions
Transportation of fuel	Departments of Coal/Petroleum & Natural Gas/Min of Railway, Shipping & Surface Transport

Annex 3
Time and cost over run of VIII plan major and medium H.E. projects

Name of the project	*Installed capacity (MW)*	*Capacity addition during plan (MW)*	*Estimated cost (Rs. in crores)*		*Cost over run (%)*	*Commissioning schedule*		*Time over run in years*
			Ori.	*Latest*		*Ori.*	*Actual*	
CENTRAL SECTOR								
1. Salal (NHPC)	3x115	343	35.15 (1970)	582.00 (1990)	955	1974-75	Commd. (87-88)	13
2. Kopili (NEEPCO)	2x25+2x50	103	36.77 (1974)	243.82 (1990)	330	1982-83	Commd. (87-88) 100 MW	5
3. Panchat Hill (DVC)	1x40	43	16.03 (1977)	52.92 (1991)	293	1982-83	Rotated (89-90)	7
NORTHERN SECTOR								
1. Anandpur Sahib (Pb)	4x32.5	134	80.73 (N.A.)	213.65 (1990)	163	N.A.	Commd. (85-86)	-
2. Mukarian (Pb)	3x15+3x15+3x19.5	152	115.58 (N.A.)	419.21 (1989)	263	1982-83 (90) 1984-85 (117)	U 1-3 Commd 83-84 U 4-12 Commd 88-89	1-4
3. Andhra (H.P.)	3x5.33	16.93	9.74 (1976)	49.02 (1989)	403	1980-81	Commd. (87-88)	7
4. Sanjay (HP)	3x40	120	55.84 (1978)	172.36 (1989)	209	1985-86	Rotated (88-89)	3
5. W.Y.C. (Haryana)	5x8	43	45.72 (1980)	117.21 (1992)	156	1984-85	Commd. (86-90)	2-5
6. Mahi Bajaj Sagar (Raj)	2x25+2x45	143	59.38 (1977)	120.30 (1992)	102	1982-83	2x25 Commd. (1985-86) 2x45 Commd. (1988-90)	3-7
7. UBDC St. II (Pb)	3x15	15	20.84 (1982)	99.92 (1991)	379	1988-89	1988-89	0

Annex 3 (Continued)
Time and cost over run of VIII plan major and medium H.E. projects

Name of the project	Installed capacity (MW)	Capacity addition during plan (MW)	Estimated cost (Rs. in crores)		Cost over run (%)	Commissioning schedule		Time over run in years
			Ori.	Latest		Ori.	Actual	
3. Bhira Tail Race (Mah.)	2x40	80	8.40 (1970)	70.86 (1989)	744	1982-83	Commnd. (87-88)	5
4. Bhandardara (Mah)	1x10+1x34	10	17.59 (1977)	65.20 (1992)	271	1983-84	Commnd. (85-86)	2
5. Pench (Mah./MP)	2x80	160	28.28 (1972)	189.57 (1992)	570	1978-79	Commnd. (86-87)	8
6. Bargi (M.P.)	2x45	90	30.49 (1977)	78.85 (1992)	56	1987-88	1987-88	0-1
7. Khadakwasla (Mah.)	2x8	16	14.29 (1983)	21.33 (1989)	49	1988-89	Rotated (89-90)	1
8. Kadana PSS (Guj.)	4x60 (St. I 2x60) (St. II 2x60)	60	24.58 (1972)	242.26 (1992)	886	1978-79	1989-90 (St. I only)	11
SOUTHERN REGION								
1. Nagarjunasagar PSS (St. II) (AP)	3x100	100	33.73 (1981)	73.00 (1992)	34	1983-85	Commnd. (84-86)	1
2. Srisailam St. II (A.P.)	3x110	330	39.33 (1981)	36.00 (1984)	42	1984-86	Commnd. (85-87)	1
3. Pochambad (AP)	3x9	27	13.49 (1984)	22.51 (1989)	67	1987-88	1987-88	0
4. Nagarjunasagar RBC Extn. (AP)	1x30	30	15.25 (1983)	17.50 (1992)	15	1987-88	Rotated (89-90)	2

Annex 3 (Continued)
Time and cost over run of VIII plan major and medium H.E. projects

Name of the project	*Installed capacity (MW)*	*Capacity addition during plan (MW)*	*Estimated cost (Rs. in crores)*		*Cost over run (%)*	*Commissioning schedule*		*Time over run in years*
			Ori.	*Latest*		*Ori.*	*Actual*	
8. Idukki St.II (Kar)	3x130	390	31.68 (1973)	70.00 (1989)	121	1984-85	Commnd. (85-87)	1-2
9. Servalar (T.N.)	1x20	20	9.35 (1974)	46.56 (1989)	458	1978-79	Commnd. (85-86)	7
10. Kadamparai (T.N.)	4x100	400	35.12 (1973)	181.33 (1991)	416	1978-79	Commnd/Rot-ated (87-89)	9-10
11. Lower Mattur (T.N.)	3x15	120	83.60 (1973)	171.79 (1991)	105	1981-82	Commnd/Rot-ated (87-89)	6-7
12. Kundan (T.N.)	1x20	20	5.03 (1980)	14.00 (1992)	173	1987-90	Rotated (1987-89)	0
EASTERN REGION								
1. Rangali (Orissa)	2x30	100	35.32 (1973)	139.77 (1988)	296	1982-83	Commnd. (85-86)	3
2. Upper Kolab St. I (Orissa)	3x30	240	51.39 (1973)	204.01 (1991)	297	1980-81	Commnd. (87-90)	7-9
3. Rangali Extn. (Orissa)	3x50	100	40.55 (1985)	71.00 (1991)	75	1988-89	Commnd. (89-90)	1

Annex 4
Time and cost overrun of hydroelectric projects during Sixth Plan (installed capacity above 3 MW)

Name of project	Installed capacity (MW)	Estimated cost (Rs. in crores)		Cost over run (%)	Commissioning schd.		Times over run (years)
		Orig.	Latest		Orig.	Latest	
NORTHERN REGION							
1. Bassi Extension (HP)	1x15	4.45	4.74	6.5	1978-79	1980-81	2
2. Garhwal Rishikesh Chilla (UP)	4x36	40.90	99.70	143.7	1977-78	1980-81	3
3. Shanan Extension (Pb)	1x50	13.26	27.25	105.5	1978-79	1981-82	3
4. Baira Siul (HP) (Central)	3x60	20.49	147.55	620.1	1974-75	1980-81	6
COMMON							
5. Pong Dam Extension (Pb)	2x60	21.91	29.79	36.0	1981-83	1982-83	1
6. Dehar Extension (HP)	2x165	28.28	40.87	44.5	1981-83	1982-84	1
7. Mukerian (Pb)	3x15+3x15+ 6x19.5	115.58	419.21	263.0	1982-85	1983-89	1-4
8. Yamuna St. II (UP)	4x30	17.96	65.16	263.0	1972-73	1983-84	11
9. Binwa (HP)	2x3	4.32	12.74	195.0	1980-81	1984-85	4
10. Manari Bhali St. I (UP)	3x30	17.78	83.90	371.8	1982-83	1984-85	2
WESTERN REGION							
1. Koyna Dam PH (Mah.)	2x20	2.17	15.76	626.3	1979-81	1980-81	1
2. Paithan (Mah.)	1x12	5.96	15.24	155.7	1981-82	1984-85	3
SOUTHERN REGION							
1. Nagarjunasagar PSS-II (AP)	3x100	55.75	75.00	34.0	1983-85	1984-86	1
2. Kalinadi St. I (Ktk.)	6x135+2x50	126.63	359.00	184.0	1977-82	1979-86	2-4
3. Srisailam St. I. (AP)	4x110	45.75	523.90	1045.0	1981-82	1982-85	1-3
4. Nagarjunasagar RBC (AP)	2x30	18.19	28.94	59.1	1982-83	1982-84	1
5. Donkarayi (AP)	1x25	7.92	13.00	64.1	1981-82	1983-84	2
EASTERN REGION							
1. Jaldhaka St. II (WB)	2x4	3.16	18.96	500.0	1978-79	1983-84	5
2. Suberorekha (Bihar)	2x65	15.27	34.07	123.1	1970-71	1980-81	10
NORTH EASTERN REGION							
1. Guniti Extension (1x5 (Tri.)	1x5	1.91	5.90	193.2	1982-83	1983-84	1
2. Kopili (Assam) (Central)	2x25+2x50	56.17	243.82	330.0	1982-83	1983-85	1-2 (for 2x25 MW)
3. Loktak (Mani) (Central)	3x35	10.90	129.98	1092.5	1975-77	1983-84	7-8

Annex 5
Ratio of average cost to average revenue (1991/92)

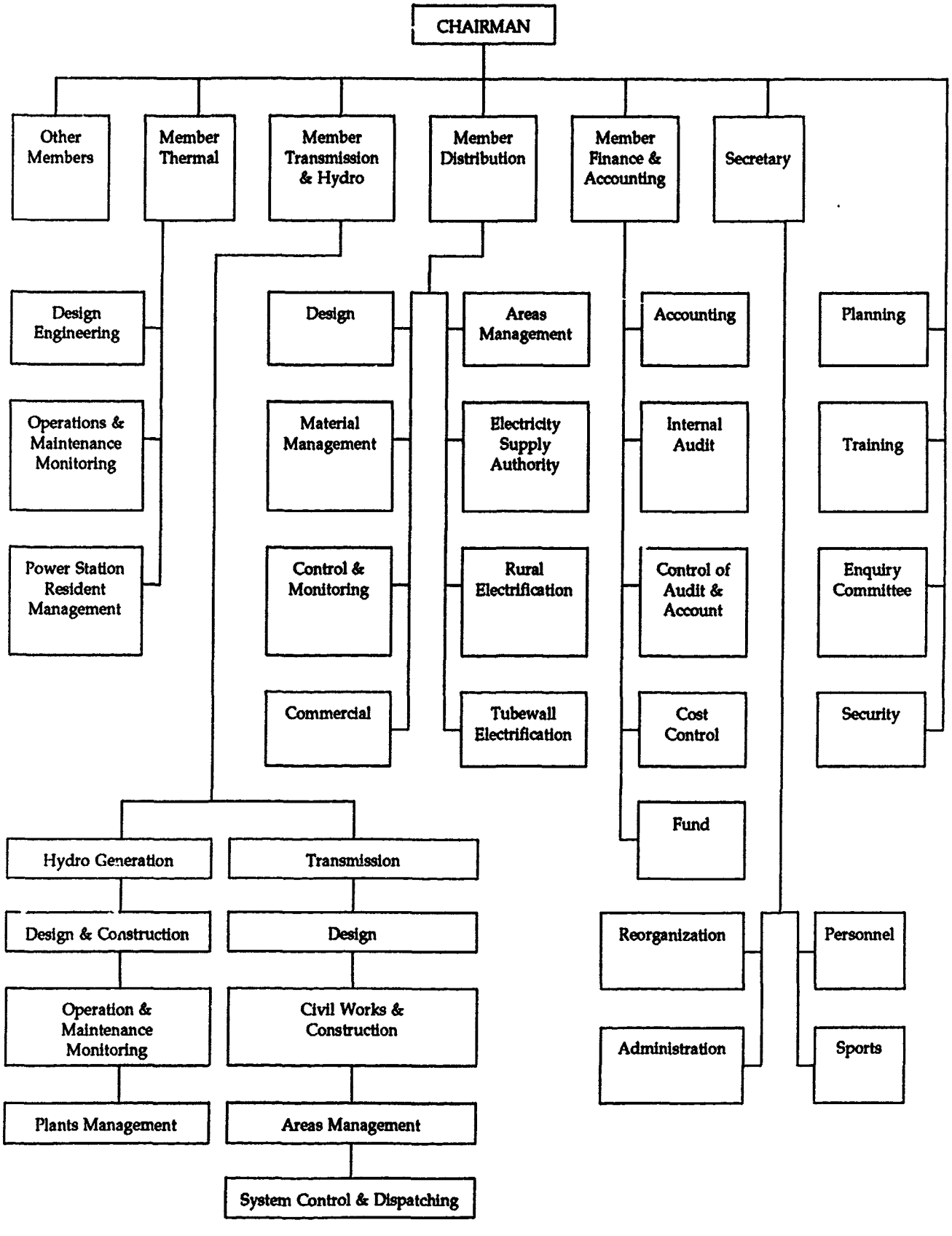
State	Domestic	Commercial	Agricultural	Low Tension	High Tension	Average rate
AP	1.22	0.59	43.37	0.76	0.56	1.00
Assam	5.04	2.61	6.05	5.10	3.21	3.25
Bihar	2.26	1.67	16.94	1.07	1.23	1.74
GEB	1.78	1.78	7.91	1.05	0.95	1.55
HSEB	1.64	0.79	4.93	0.86	0.99	1.37
HP	2.59	1.14	4.51	1.41	0.00	1.54
KEB	0.97	0.39	20.13	0.55	0.67	0.97
KSEB	1.42	0.88	3.14	1.15	1.19	1.23
MPEB	4.12	1.01	7.74	1.04	0.84	1.25
MSEB	1.70	0.78	7.92	1.07	0.74	1.09
Meghalaya	2.84	1.69	5.66	2.16	2.16	2.27
OSEB	1.41	0.74	2.41	1.22	0.96	1.04
PSEB	1.25	0.75	11.65	1.11	0.91	1.77
RSEB	1.92	1.05	3.75	1.00	0.81	1.21
TN	1.96	0.80	0.00	0.84	0.89	1.27
UP	1.69	1.06	4.38	0.90	0.00	1.55
WB	2.42	1.44	6.18	1.72	1.28	1.31

Annex 6
State electricity duty (SED) as proportion of average revenue (paise/kWh sold)

S. No.	Board	1989-90			1990-91		
		Average rate	SED	(%)	Average rate	SED	(%)
1.	Andhra Pradesh	66.65	2.33	3.50	74.80	2.25	3.01
2.	Assam	87.87	1.77	2.01	94.84	2.04	2.15
3.	Bihar	86.80	1.90	2.19	92.21	1.90	2.06
4.	Gujarat	81.10	9.68	11.93	81.45	9.71	11.92
5.	Haryana	58.68	5.06	8.62	82.40	6.19	7.51
6.	Himachal Pradesh	64.56	2.54	3.93	79.13	2.20	2.78
7.	Jammu and Kashmir	40.23	4.90	12.18	38.00	4.30	11.32
8.	Karnataka	65.80	5.35	8.13	79.70	5.47	6.86
10.	Kerala	55.00	7.58	13.78	53.04	7.35	13.86
11.	Madhya Pradesh	83.72	13.43	16.04	83.15	13.43	16.15
12.	Maharashtra	83.22	4.37	5.25	103.06	4.35	4.22
13.	Meghalaya	50.30	0.65	1.29	59.21	0.85	1.43
14.	Orissa	65.78	11.16	16.97	72.38	11.34	15.67
15.	Punjab	46.90	4.22	9.00	54.87	4.53	8.26
16.	Rajasthan	76.67	4.85	6.33	89.27	4.86	5.44
17.	Tamil Nadu	73.34	-	-	85.13	-	-
18.	Uttar Pradesh	71.47	2.37	3.32	73.09	2.34	3.20
19.	West Bengal	103.43	1.85	1.79	103.51	1.84	1.78
All Boards' Average		74.62	4.84	6.49	77.84	4.26	5.47

Source: Annual Report on the Working of State Electricity Boards and Electricity Departments, Planning Commission, Government of India, August 1992.

Annex 7
SEB - Organizational chart



Annex 8
Indicators for manpower utilization (1991-92)

Board	Employees per million kWh of electricity sales	Employees per MW	Employees per '000 consumers
Andhra Pradesh	3.96	14.15	9.84
Gujarat	2.14	8.96	6.95
Haryana	5.95	25.55	16.69
Himachal Pradesh*	12.10	44.85	12.72
Karnataka	3.51	14.83	6.95
Madhya Pradesh	6.65	30.66	17.31
Maharashtra	3.63	14.16	12.02
Orissa	5.38	18.63	29.25
Punjab	5.87	22.95	19.52
Rajasthan	5.75	20.23	16.49
Tamil Nadu	5.16	20.40	10.46
Uttar Pradesh*	5.09	19.86	23.06

* Data for 1990-91
Data on employees for Assam, Bihar, Kerala, and West Bengal is not available.

Annex 9
Revenue outstanding as percentage of total revenue

S. No.	Name of the SEB	1985	1986	1987	1988	1989	1990	1991	1992
1.	Andhra Pradesh	19.70	21.29	23.37	26.85	29.23	33.40	27.63	27.87
2.	Bihar	70.64	70.37	43.80	64.69	77.37	87.32	98.13	94.52
3.	Gujarat	13.49	18.51	26.06	23.37	25.72	26.07	25.57	23.99
4.	Haryana	25.28	51.88	49.28	42.79	34.60	38.34	66.87	73.74
5.	Himachal Pradesh	28.57	28.61	64.81	55.59	27.07	53.31	51.90	56.82
6.	Karnataka	33.21	46.46	52.57	58.18	64.86	58.34	50.32	46.12
7.	Kerala	30.97	24.91	23.88	23.88	22.66	31.92	35.70	37.04
8.	Madhya Pradesh	25.11	27.98	29.07	29.07	39.33	45.02	N.A.	N.A.
9.	Maharashtra	20.73	21.79	23.14	29.13	28.90	28.77	30.85	26.83
10.	Orissa	36.73	35.18	35.55	36.39	32.68	38.65	44.92	N.A.
11.	Punjab	13.62	16.15	18.77	19.11	21.36	18.42	17.25	18.00
12.	Rajasthan	29.30	26.07	21.58	23.99	9.49	17.77	16.73	15.02
13.	Tamil Nadu	9.86	14.04	12.02	13.82	12.81	13.06	11.64	13.06
14.	Uttar Pradesh	33.52	35.95	31.01	38.25	39.69	48.33	48.71	51.81
15.	West Bengal	20.87	24.20	25.48	25.63	29.04	27.93	35.75	N.A.
16.	Assam	24.63	N.A.	N.A.	N.A.	N.A.	N.A.	28.82	38.86
17.	Meghalaya	93.24	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Total		24.54	27.63	24.71	31.12	32.96	34.90	34.29	33.44

Commercialization of the power sector in India

by
Administrative Staff College of India

Preface

This paper is presented in four parts.

- **Part 1:** sets out the summary of the paper giving briefly the sector level measures required for making the State Electricity Boards (SEBs) function on commercial lines and to give a sense of commercialism to the entire power sector in India.
- **Part 2:** sets out the rationale for the reforms suggested in Part 1 and how they could be implemented.
- **Part 3:** gives the micro-level measures to be taken by the SEBs to remedy the shortcomings of the financial operations.
- **Part 4:** gives transitional measures to be initiated immediately.

1. Executive summary

A study of the Indian power sector shows that while it has registered a fast expansion in quantity terms, it has steadily deteriorated in all other parameters. The main shortcomings of the power sector have been recognized a long time back and several measures were taken from time to time to remedy these. In actual terms, these measures could not be implemented and power sector performance, as a whole, has deteriorated both in terms of technical efficiency and financial performance. Throughout the eighties, the gap between what the power industry should achieve and what it could achieve widened. In the decade of the nineties, the technological advances in several industries are likely to accelerate power demand in terms of quantity and quality. The central and state governments and the SEBs have realized that, by themselves, it would be impossible to meet the anticipated demand even quantitatively, let alone meeting it qualitatively.

The Government of India (GOI) has, therefore, proposed to permit the private sector to set up generating stations and sell the power to the SEBs. A number of concessions have been given to private-sector investors to attract them to invest in the power sector. The target for private-sector power generation in the Eighth Five Year Plan (FYP) was set at 8,000-10,000 MW. A large number of independent power developers from within the country and outside have initiated discussions with the different SEBs. Though the public agencies involved have published only scanty details, the latest information is that the private sector has so far signed Memoranda of Understanding for over 28,000 MW of power. Even if all those projects materialize, they will not remedy the basic problem which the electricity sector faces. The purchase of power from the private sector is not very different from the SEBs' purchasing power from the central power generating stations. The SEBs are finding it difficult to pay for the power purchased because of the low tariffs which are inadequate to cover the operational cost and the costs of purchased power. The same situation will continue even when private independent generators sell power to the SEBs.

The crux of the problem lies in the SEBs improving their financial performance by becoming commercially viable units capable of fulfilling their mission.

The SEBs can fulfill their mission of supplying the power needs of the consumers in their area with electricity of appropriate quality at reasonable (competitive) prices, only if they function as commercial entities. Commerciality of the SEBs would imply:

- Ability to meet the power needs of the customers in the area efficiently
- Ability to make decisions without any external interference, along commercial principles
- Ability to meet promptly all financial obligations to the suppliers of inputs and power (like central and independent generators)
- Ability to fully meet debt servicing and debt redemption obligations
- Ability to generate at least the statutory minimum surplus by their operations
- Ability to raise commercial finance and the freedom to contract from power supply for independent generators.

A careful, in-depth examination of the failure of the earlier attempts to reform the power sector in India suggests that there are serious structural barriers which impede the implementation of the financial reforms for commercialization. The solution to the power sector's problems, therefore, rests in effecting major structural, institutional, and regulatory reorganization as a prelude to implementing other financial reform measures.

The core of the structural, institutional, and regulatory reform is aimed at strengthening the (financial and executive) autonomy of the SEBs, while at the same time enhancing competitive conditions in the power sector. This would involve:

- A proper demarcation of the relative role of the central and state governments in power sector management, based on the managerial and financial autonomy of power utilities
- Empowerment of the SEBs to adopt different options of generation, transmission, and distribution to meet the needs of electricity of all consumers
- Corporatization of the SEBs and sale of equity to all stake holders, especially to power consumers
- Deregulation of the power market for larger, high-tension (HT) consumers of electricity
- Organization of Regional Power Pools
- Restructuring the regulatory mechanism towards a transparent and autonomous regulatory process.

We shall in this part (Part 1) only highlight the essential features of the reforms listed above leaving the detailed discussion to Part 2.

1.1 *Demarcation of the role of state and central governments in the power sector*

The Indian power industry is governed by two Acts. One which was enforced before independence, the Indian Electricity Act, 1910, and the other post-independence, the Electricity (Supply) Act (E(S) Act), 1948. It is clear from these Acts that the responsibility for the power supply is vested with the SEBs. The role of coordinating the efforts of the different states by prescribing the general rules and common standards is given to a technical body, the Central Electricity Authority (CEA). Under the Indian Electricity Act, 1910, state governments can license anyone to generate electricity in any specified area and can acquire any small electricity company to

combine into a state grid. Under the E(S) Act, GOI (central government) had the authority to constitute the CEA. The CEA is a totally technical agency subject to directions from the central government, empowered to take measures to develop a uniform national power policy and secure the optimal utilization of resources.

However, over the years, the central government gradually assumed greater direct responsibility for the planning and development of power for the country as a whole. This became necessary because of the financial inability of the SEBs to develop power to the adequate extent required. In turn, the SEBs leaned towards state governments for financial supports, adding to the increasing dependence of state government budgets on central devolution. The large capital-intensive power projects in the eighties made this almost unavoidable for the SEBs. Even by the middle of seventies the central government had felt that the SEBs cannot be relied upon to generate adequate power for the developmental needs of the country. This was the period when large generating power companies like National Thermal Power Corporation (NTPC) and National Hydro Power Corporation were set up by the central government.

The centralization process has proceeded so far that private power companies invited under the recent reforms to set up power generation and supply power to the SEBs, expect central sovereign guarantee.

The New Economic Policy (NEP), however, envisages a different scenario wherein market orientation may not be complimentary to the centralized scenario. Power corporate entities would have to be autonomous and guided by market forces. The entire planning process has now been modified to indicative planning. Therefore, the immediate reform should be for the state governments and central government to revert to their roles assigned under the two Acts, governing the power industry and allow the SEBs to play their respective role. Simultaneously, the CEA reverts to its technical character as the highest coordinating body to guide the SEBs on technical matters with only directions of broad policy issue from the central government. The state government, which is elected to represent the best interest of its constituency, should become the protector of the rights of all classes of consumers. It should use the powers of granting licenses for power generation whenever it is in the best interest of the consumers. Thus, the envisaged scheme can be conceived of institutional reforms at three levels: (1) autonomy of SEBs; (2) redefining center-state relations; and (3) advisory role of the CEA.

1.2 *Empowerment of electricity Boards*

The role, responsibility, and power of the SEBs are well defined in the E(S) Act. The SEBs have the monopoly right to generate and distribute power in the respective geographical area. Before the NEP, when specific targets for the growth for all sectors were set out in the FYPs, electricity demand was also derived from the FYPs. Setting of targets essentially involved identifying and locating large, energy-intensive industries among the different states. The SEBs' responsibility was only to fulfill these predetermined targets. With the liberalization program of the NEP, most industrial targets have become indicative. The SEBs no longer have clear prior indication of the industries that would materialize in their state. As a result, the SEBs will have to decide the targets themselves based on the assessment of market opportunities and their specific strengths.

In Section 1.4, which follows, the feasibility and need for deregulation of the HT consumer market is discussed. Normally in the SEBs, the low-tension (LT) load for power is about 40 to 50 percent of the total demand, and this demand grows gradually on predictable lines. The SEBs should assume the responsibility to meet the LT demand in their area. HT demand would be met to the extent that the SEBs are in a position to increase their installed capacity. Demarcation of HT consumers can, in the future, be refined to allow for deregulation of distribution and generation, with distinct generation/distribution companies for HT consumers. This would reverse the trend of increasing dependence of the SEBs on state funds and in turn on central funds. The centralization process, gradually modifies to decentralized processes.

The GOI is no longer in a position to provide for the huge funds required for power development in the country as a whole. It has, therefore, amended the E(S) Act to permit private power generators to supplement the SEBs' generation. Under the legal provision, the agreement between a private power generator and the SEBs would be a purely commercial agreement subject only to certain technical parameters to be prescribed by the CEA. However, in practice, the GOI continues to assume a large role for itself by trying to negotiate between the private parties and the SEBs including settling the terms of the Power

Purchase Agreement (PPA). Experience of the few agreements signed show that, due to the increase in capital costs and the higher return and higher depreciation rate given to private power generators, the costs at which the SEBs are likely to get their power from the independent power producers is very high compared to their own power generators. So far, no steps have been taken to ensure that the tariffs levied by the SEBs should be raised adequately to cover the cost. The results of such half-measures are likely to be disastrous to the SEBs. The commerciality of the SEBs lies in the present context in their ability to negotiate with the private parties on purely commercial lines. This should include a process of bidding by which the SEBs can select the private unit offering the lowest price. Further, the SEBs must also have the power to decide for themselves the areas of generation and distribution which could be privatized and shared with other entities. This may require modifications to the E(S) Act.

In sum, the SEBs need not pursue targets of power supply set for them by other agencies. They would have responsibility to supply the needs of LT consumers only. Their responsibility to supply the needs of HT consumers will gradually get reduced. The SEBs would have the power to supply HT consumers to the extent of the capacity of their supply system. The SEBs could invite the private sector to generate power and sell it to them. They would have full powers to negotiate and settle the contract in the interest of the consumers and the SEBs. The tariff for noncompetitive supply to LT consumers would be subjected to regulation (Section 1.6 below), which would ensure that the SEBs get a total revenue which covers all their costs and provides them with a return on the basis of investment as laid down in the E(S) Act.

1.3 Electricity boards as corporations

If the SEBs have to take up an entrepreneurial stance as indicated above, corporatization of the SEBs is inevitable. A corporate form will enable the SEB to raise money from the capital market or from financial institutions, while reenforcing the move towards autonomy. As a first step, the SEBs can be converted into public limited companies registered under the Companies Act. The interesting exercise is with regard to the possible and relevant debt-equity ratios. By and large, the prevailing financial structure of the SEBs suggest a debt-equity ratio of 1:1. At this ratio, it can be seen that, in the case of surplus generating units like APSEB, conversion into a company form overstates their profitability, whereas in the case of loss-making companies, the losses get exaggerated. The company form is not to be resorted to as an accounting gimmick but as a means of distancing the SEBs from the state governments, raising finance from different sources, and becoming more accountable to the stakeholder.

Corporatization also raises the issue of restructuring the capital of the SEBs to make it attractive to investors. This may call for the write-off of large amounts of loans which are shown as due from the SEBs to state governments. These loans are not likely to be collected by the state governments at any point of time and as such, it would be appropriate to write them off. With a properly dressed up financial statement, the electricity boards should be in a position to seek funds from the market.

As a public limited company, the various stakeholders in the electricity boards should be encouraged to take shares. This would ensure the requisite accountability of the new company. Preferably, all the consumers should be encouraged to invest in the equity of these companies. In proportion to the investment, different classes of shareholders could be represented on the Board. The Board alone, without any external interference, should have the power to choose their chief executive and other functionaries.

1.4 Deregulating the market for large, high-tension consumers

In the present setup, all consumers have to get their supply of power from the electricity boards. Any reform of the power sector should sow the seeds of competition at the consumer end. This can be done only by selecting a group of consumers whose supply deregulation will not upset the arrangements in respect of others. While the total number of consumers is several million, the number of consumers who take power supply from 132 KV transmission lines are only about 1,000. But they account for 10 percent of total power consumption. If these consumers are separated and made part of an emerging supply system, it would not affect the electricity Boards' other operations. These large consumer groups could also bid for power purchases from the local SEB, central power companies, or independent power developers, who might have excess capacities after meeting their obligations to electricity Boards, or private

generation which could be set up to meet the power demand of some large industrial consumers.

Once the deregulated power supply system gets stabilized, the scheme would be extended to other large consumers who take power from 132 KV. This scheme would set in the competitive process through purchase and sale of power among a small number of consumers from a small number of sellers of power.

1.5 *Organization of the regional power pools*

The best option of servicing the needs of large power consumers is to have a national supply system operated through the cooperative efforts of the National Power Grid Corporation and the SEBs, until such time as commerciality of the SEBs enables prices to coordinate grid activities. This will take time. Meanwhile, there could be an arrangement to meter the transient surplus with some producers with demands not met by long-term arrangements on a day-to-day basis and on a seasonal basis. The power generating agencies, viz., SEB, central generating companies, and private power generating corporations, could be involved. The temporary demand would come from SEBs which could not be met from their own system and from large consumers, whose long-term contracts cannot supply needs of that particular day or season. The regional pool is intended to match this surplus with the demands on a temporary day-to-day basis and on a season-to-season basis. It is possible for each of these power generating companies to indicate their anticipated surplus availability during certain seasons annually and the surplus on daily basis. Similarly, the power needs also will be indicated to the same agency. National Power Grid Corporation will be given the responsibility to match the surplus availability and temporary demand. The Regional Electricity Boards (REBs) could indicate the general guidelines as to how it should be operated within the region. In other words, to begin with, the REBs may determine the rates at which the surplus power would be sold to these demanding agencies. But the Regional Pool System should quickly progress to a stage where the supply company indicates the cost at which they would like to sell power and the demanding consumers could opt to the particular source at a particular price.

When the proposal was discussed with some officials of the SEBs, they considered this to be a complicated and unworkable system; a system on more thinner time slices of a half-hour each for the daily offer and acceptance is operated very satisfactorily through the Pool Price System in the U.K. now.

1.6 *Regulation in the power sector*

Under the new reforms, the envisaged regulation in the power sector assumes importance. But, the form and extent of regulation vary depending upon the reforms introduced. Utilities, despite technological developments, display market imperfections that hinder competitive forces. These failures come about due to the existence of significant scale economies, inadequately defined property rights, informational asymmetries, environmental considerations, and excessive transactions costs. Traditionally, government intervention through a regulatory agency has been the general *modus operandi*. Regulation has also been the process of introducing noncommercial distributional considerations of governments. The sovereign role of the state tended to get mixed-up with the regulatory role. But in the current context of market reforms, traditional forms of regulation may only contribute to existing state failures. It is necessary, therefore, to seek self-regulatory or internalized regulatory mechanisms that do not perpetuate existing state failures.

At the outset, a few basic guidelines may help in developing the new regulatory framework. Firstly, the main purposes of regulation are to resolve conflicting interests, ensure competitive behavior, and protect consumers interest. In a segment where monopoly elements persist, competitive elements need to be stimulated through benchmark pricing schemes; for example, the supply of power at regulated prices to LT consumers and other HT consumers below the deregulated category. Secondly, regulatory mechanisms should be transparent. Finally, efforts towards arm's-length regulation should be attempted by vesting a monitoring role to the regulatory agency through which it can always protect the general interest, even if it requires action to prevent interferences from external sources. In the transition period, the above guidelines may be modified.

Regulation is required in the following four areas. They are:

1. Regulation at entry point to stimulate competitive conditions and also maintain a balance among different generating units

2. Regulation at the operational level to ensure the smooth and safe functioning of the grid at both the national and state level until tariffs evolve towards merit order operations
3. Regulation through an agency for the optimal utilization of natural resources, especially in the context of skewed distribution of fuel resources within the country
4. Regulation to ensure equitable distribution of power as between big and small consumers, between consumers whose supply is not deregulated, and the consumers in the deregulated competitive market.

2. Proposals for the commercialization of the power sector

In this part, the proposals for commercialization of the power sector are examined in detail and the ways of implementing the proposals are identified.

2.1 *Demarcation of the state and the central government's roles*

In the fifties and sixties, the GOI was concerned with the issue of broad guidelines to the SEBs on power development. It was found that, over the years, the SEBs were slowly losing their ability to fulfill the responsibility cast on them under the E(S) Act. From the Third FYP, when large industrial investments were made in the central sector, the central government felt that it had to take a more direct responsibility to forecast the demand for power in the different states and "help" the states to implement a power development program of the right size. When state governments could not allocate adequate funds to the power sector, the Planning Commission started giving special central assistance to implement power projects and the power ministry at the center started closely monitoring the implementation. Table 1 below shows the increasing dependence of the SEBs on states' funds and less on internal resources. If market borrowing and institutional loans which are on the basis of state guarantee are included, the proportion given is much higher. It is interesting to note here that state funds have decreased in 1990, suggestive of decreasing budgetary support, but institutional loans have increased.

The first and most comprehensive document on energy issues was the report of the Fuel Policy Committee (FPC) accepted by the government in 1975. The emphasis of the Report (FPC) was on the coordinated development of coal, oil, and electricity. At that time, production of coal and oil were monopolies of the GOI. Power alone was decentralized and under the jurisdiction of the different states. In the face of the recommendations of the FPC, the GOI felt it necessary to assume a larger responsibility for power production and also to effectively coordinate towards optimal utilization of all forms of energy sources. When the central power generating companies were set up in 1975, it was decided that power generated in each location would be divided among the states in that location in a predetermined ratio. Though there is nothing in the rules governing the central generating companies to supply power in a pre-fixed ratio to the states of the region, the central government preferred to give directions on these ratios.

Such modes of operation are bound to change under the NEP wherein implications of the "roll back of the state" has changed the relationship

Table 1
Pattern of financing (%)

	80-85	*85-86*	*86-87*	*87-88*	*88-89*	*89-90*	*90-91*
State government	55.5	57.1	61.7	73.3	77.0		68.0
Market	95.1						
Borrowing	14.7	12.9	12.3	16.9	13.0	8.0	
Institutional Loans	29.4	27.6	34.6	35.3	41.0	43.0	
Internal resources	3.9	0.5	2.4	-8.6	-25.4	-31.0	-19.0

Source: Government of India, Power and Energy Division, Annual Report on Working of SEB and EDs., May 1989.
Notes: The break-ups with regard to Pattern of Financing were tabulated only from 1985 onwards. Hence in the period of 1980-85 we only have aggregate values.

between public enterprises and the governments. Public undertakings are being distanced from the government and forced to function in competition with private industry. They are also not given any special assistance. This is equally true of central power generation companies such as NTPC. The legitimate purpose of NTPC setting up a project in a state should be to exploit the resources of fuel or water located in a state, which the state concerned was not finding it necessary or convenient to exploit. It would be quite justifiable once the project is set up by the GOI, the central generating companies sell the power to the SEBs on the basis of their need and willingness to pay. The earlier pre-fixed ratios and the role of the central government becomes redundant.

Similarly, the role of the CEA and the relation to GOI undergo a change. The CEA was originally intended to be a technical regulatory body with the GOI retaining the powers to give directives. Asymmetry of knowledge and information with the CEA and the GOI, clearly defined the scope of directives from the GOI to the CEA. They were to be only on broad policy issues. Over the years, however, the GOI, in their anxiety to play a more active role in the power sector as part of the centrally planned management of development, pushed the CEA into different roles such as power demand forecasting, consultancy, etc. Under the NEP, the forecasting of power demand in such detail, as attempted by the CEA, though the Power Survey, has become unnecessary and to some extent futile.

Under these conditions, the CEA can easily revert back to its role originally envisaged in the E(S) Act. The exercises of working out the possible industrial investment and deriving the state-wise power demand year wise was a justifiable exercise during the period prior to the NEP, when all investments in all sectors were subject to the approval of the GOI in one form or the other. In the current context of economic liberalization, for almost all industrial investments, no permission from the GOI is required. Industries, therefore, would seek locations where there are bright chances of getting inputs including power. The gestation for power generation projects is much longer than most of the industrial investments. Power development should therefore be a step ahead of the industrial development and would be based on the entrepreneurial ability of the states. States, therefore, would have to anticipate, in broad indicative terms, power requirements for the plan period. These requirements depend largely on expected industrial growth and the rate of energization of agriculture pumpsets combined with the trend projection of demand in the household and commercial sectors. Scenario building for industrial growth depends on state policy and resource availability. Trend projections are not robust for such projections, persuading the SEBs to target alternative rates of growth.

The SEBs can then plan for supply additions under different options open to them:

- Enhance or add to installed capacity under their ownership
- Negotiate with independent power developers to set up new generation units
- Negotiate with central power generating companies.

The firmed-up plans for setting up projects of their own, plus firm commitments of supply obtained through negotiations with central power companies or independent developers, form the power development plans of the SEBs. With power, follows industrial investment. Industries would seek locations anywhere in the country where there are bright chances of supply of the requisite inputs, including power. The states which have a good power development plan attract the new industries. Under this system, the SEBs plan for their growth based on their own strengths while taking due note of the state's development plans.

The special funding of central assistance by central governments to state governments for implementing power projects may be insufficient and perhaps inappropriate. Devolution of resources from the central to state governments would then be left to the discretion of the state regarding its allocation among sectors. In effect, the reform proposed is for the state and central governments to revert to their original role of providing broad policy guidance. The GOI would set the policy and procedures of foreign investment in the power sector and set the pace of development for the power sector by the growth impulses in their overall approach to industrial investment. The GOI would approve the formation of generating plants under Sections 15A of the E(S) Act. State governments provide some elements to the target for power development by their social development plans and energization plans for agricultural pumpsets. State governments would also grant licenses for power generation and distribution under Section 3 of Indian Electricity Act. In essence, state

governments fulfill the objectives of the E(S) Act by becoming the true guardian of the consumers of electricity. Both governments would distance themselves from the SEBs and future corporate groupings set up to generate power and supply the electricity needs of all the consumers.

2.2 *Empowerment of the SEBs and their corporatization*

The SEBs are notoriously poor in their financial performance. The causes are technical, managerial, and institutional. So far, several attempts have been made to correct these technical and managerial shortcomings. They have met with little success as reflected in the increasing accumulated losses of the SEBs. The Table (Table 2) gives a birds-eye view of commercial profit and loss of some SEBs.

A careful examination of the causes for the failure of the reforms attempted on the SEBs shows that they lie in the SEBs surrendering their powers and responsibilities to the state governments. The E(S) Act clearly defines the roles of the SEBs and the extent to which their work can be monitored or supervised by the state governments.

Basically, state governments have two functions. First, the state governments have a very important role in appointing the members of the SEBs and nominating one of the members as the Chairman. Second, if the state governments do not fix any limit, the return above cost should be 3 percent as prescribed in the Act. The surplus rate of return over cost could accrue as revenue while fixing the tariff. Under these two functions, the state governments have no other role except to do an annual review of the SEBs' work. Interestingly, tariff fixation is entirely within the competence of the SEBs and is governed by Sections 49 and 59 of the E(S) Act. But state governments invariably have assumed the powers invoking the ownership rights over the SEBs and introduced in tariff fixation. The major causes for the poor financial performance of the SEBs is the tariff fixed under the direction of the state governments. Tariffs in general have remained well below the average cost of generation and supply. The tariff also provides a high level of subsidy to agricultural consumers but state governments fail to carry the cost. The Table below sets out some details.

Besides fixation of tariff, the state governments' influence or intervention in the SEB functioning relates to specifying the villages which should be energized each year and the number of agricultural pump-sets which have to be energized. Needless to say, these proposals, although socially justifiable and politically significant, are nonviable. Therefore, implementation of these projects add operationally and financially to the losses of the SEBs. In such cases, the state governments can spread the burden through capital contribution to the project. The obfuscation of the role of the state governments as owner and as a provider of social goods to the weaker section is largely responsible to the SEBs running into operational deficits.

The SEBs cover the deficits by loans from state governments. This gives scope for the state governments interfering in other matters also. In

Table 2
Commercial profit/losses (-) at current rates (excluding subsidies) during Seventh Plan (1985-90) period for a few states (Rs. crores)

State	*1985-86*	*1989-90*	*1985-90*
Andhra Pradesh	-9.65	-54.36	-101.66
Bihar	-191.73	-283.10	-1,211.85
Gujarat	-123.08	-383.57	-952.46
Karnataka Board	-26.78	-98.43	-355.14
Kerala	4.83	-16.18	-119.56
Maharashtra	-57.43	-3#9.10	-487.80
Punjab	-144.97	-565.15	-1,696.01
Uttar Pradesh	-325.28	-172.06	-615.49
Total	**-874.09**	**-1,528.38**	**-5,539.97**

Source: *Government of India, Power and Energy Division; Planning Commission, Annual Report on the Working of SEBs and ED; August, 1992.*

Note: *Data representing good, medium and poor performing SEBs have only been tabulated. The totals are however of all states. Detailed Table is given in Annexure 1B.*

effect, the SEBs have been reduced to the levels of subordinate offices of the state governments. Given this situation, any managerial change which does not distance the state governments from the SEBs will be no solution. Some states have attempted to separate power generation from transmission and distribution (T&D). This has only created a power company like central power companies which is unable to collect the cost of power sold to the T&D entity.

The key issue is the extent to which the T&D entity can function as a commercial institution. For this, the state governments should be kept out of the affairs of the SEBs. Distancing of state governments from the SEBs could be achieved by converting the SEBs into companies with equity participation by the stakeholders. The existing provisions of the E(S) Act permit equity participation. Under Section 12A, the state governments can declare the SEBs as a corporate body with equity capital of Rs. 10 crores initially. Under the same section, the state governments may take the approval of the state legislature and increase the level of capital in the companies. Under Section 66A of the E(S) Act, state government can convert the loans advanced into equity.

2.3 *Deregulation of the market for large HT consumers*

Under the existing system, all consumers have to depend on the electricity boards for their power supply. Electricity boards have tariff systems which are regulated by the state governments. In times of power shortage, usually in the summer season, power to consumers is regulated under the direction of the state government who divert large quantities of power to the agricultural sector, starving large industries. In the power sector, there is no competition at all. The efficiency of the power system in the final analysis would depend upon the introduction of real competition.

Given the present structure of the power industry, it is very difficult to introduce competition at all levels and for all consumers. However, a beginning could be made with HT consumers who take their supply at 132 KV for the whole country. The composition of the consumer size class in the SEBs makes this an interesting proposition. While the LT consumers to be served by each SEB run into several lakhs, the HT consumers are only a few hundreds. However, the HT consumers account for a major share of the electricity consumption and also revenues payable to the Board. For example, APSEB, the total number of consumers to be served is over 7 million, while the HT consumers are only 3,500 but account for 60 percent of power consumption and 70 percent of revenues. The ten largest consumers in each SEB may consume over 10 percent of the total load. There is an interesting possibility of treating the HT consumers above 132 KV as part of the national grid supply system. The total number of HT consumers in the country is about 40,000 of which those who take their supplies at 132 KV would be about 1,000 only. These consumers can be liberated from the state supply system and given the freedom to purchase their requirement from any source in the country. They should be permitted to purchase power from another source within the state or outside.

The Power Grid Corporation and the State Government Boards who own and operate the transmission lines will have to accept responsibility to wheel power from the source of purchase to the point of consumption. This will create a separate market. The bidders would be the 1,000 and odd large industrial consumers who take power at 132 KV. The sellers in the market would be independent power generators inside the state and outside, the central power generating companies within the state or outside any other. A strong element of competition could be generated in this market by allowing the tariff to these consumers to be deregulated. The success of this proposal will depend on the ability to transfer power from the purchase point to the point of consumption. This would depend on the legal framework that would impose on Power Grid Corporation the responsibility to transmit power, provided the hardware has the capacity. An office of power regulation has to decide in case of a difference of opinion. Over the years, the success of this could lead to the deregulation of HT consumers of 33 KV and later all HT consumers.

The SEBs have very strong views against this deregulation. The objection is based essentially on the fear that the deregulation of high-value consumers who pay large sums as lump sum, every month would make the SEBs dependent on small consumers from whom the collection is difficult. Their fears are justified as the social obligation thrust on the SEBs of serving villages in remote areas and taking up large-scale electrification of agricultural pumps is now, to some extent, made possible by subsidization from the large consumers, as can be seen from Table 3. The large consumer subsidization would not be

Table 3 (paise/kWh)
Average revenue - cost gap of the SEBs

	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90
Average cost of generation & supply	22.52	30.45	41.90	65.07	74.64	81.17	91.47	96.07	101.65
Average realization (including agricultural supply)	18.82	22.69	32.30	49.39	59.78	67.02	71.59	74.16	76.89
Gap	3.70	3.76	9.60	15.68	14.86	14.15	19.88	21.91	24.76

Source: Government of India, Planning Commission, Report of the Working Group on Power, Eighth Plan, Power Program, September 1991.

possible and losses of the Board will increase. These fears are totally unfounded in the new context when the proposal for commercialization of the SEBs is implemented. Under the new proposal, the SEBs will fix tariffs, and consumers are left with it in such a way that the revenue covers the total cost plus providing for adequate surplus. The state governments will have to give subvention when they want to propose any schemes which are nonviable. Second, deregulation would make the Boards compete with other generating plants, as well as other Boards in the market. The efficient Board is one which succeeds in getting business.

2.4 *Organizing the regional power pools*

Currently, the SEBs operate the power system under their control as a separate independent power system, and the optimization of resources is done by following the merit order of generating stations to be brought in use as the demand increases and takes them out when the demand diminishes. Though at the regional level, Regional Load Dispatch Centers (RLDCs) are able to monitor the fluctuation in demand and supply in the region on a real-time basis, there is no attempt to optimize the resource utilization at a regional level. Even for the dispatch of power from a central generating station located in one state to another, whenever the state grid is involved, special efforts are made to get the frequency of the two states to appropriate levels to effect the transfer of power.

The lack of commercial understanding between the SEBs within the region makes it difficult to operate the regional grid as a resource optimizing unit. The tariffs being fixed on single part basis is also a deterrent to the operation of an efficient regional grid which the SEBs would try to operate. The inefficient units during the off-peak hours would cost the SEBs' fuel cost as the incremental cost. If, for optimizing the efficiency of fuel, a fuel inefficient plant owned by the SEB has switched off, and a more fuel-efficient plant under the central generating company or with another SEB is brought in, the SEB taking supply would have to pay the full cost instead of the incremental cost. Furthermore, the obligation to purchase a certain amount of power under the PPA with the central generating station also forces the SEBs to use the resource suboptimally. There were occasions when thermal power from the NTPC was used because of contractual obligations, when hydel power station within the region was spilling due to the lack of demand for power.

This situation will be aggravated if, in the process of encouraging private power generators, the SEBs enter into single part tariff rates which are very high with high levels of contracted load. These anomalies will be remedied by setting up power pools at the regional level. The potential for power supply over and above the quantity required to meet the demand of each SEB will notionally be taken as an inflow into the regional pool. This information on a real-time basis would anyway be available at the RLDCs. As of now, the RLDCs are operated by some officials of the Regional Boards, (usually, deputationists from the SEBs). This RLDC operation should be entrusted to the Power Grid Corporation. The REB should give commercial guidelines regarding the distribution of power flowing into the regional pool. Needless to say, these guidelines would be backed by legally valid agreements regarding the price and quantity acceptable to different SEBs at different times of the day.

The same kind of arrangement could be made for using surplus from efficient thermal stations,

in some SEBs during seasons of the year when their hydel contribution is high. Other SEBs with totally or mostly thermal plants would gain by the pool supply from efficient thermal plants. If the policy initiated to bring in independent power developers succeeds, the scope of the regional pool could be increased to include private generating companies on the supply side and large HT consumers on the demand side. The efficiency of such operation would depend on the presence of a well integrated regional network with a hierarchal network of load dispatch centers equipped with the facilities for metering, computation, and control.

REBs should settle the price for all possible power flows. All these prices will have to be based on a two-part tariff. REBs would also set out clearly the operating principles and the systematic operating procedures for the grid as a whole. To begin with, the Regional Board may specify only certain circumstances that the grids will operate as state grids, and optimizing between generating stations within the region would be resorted only under specified circumstances. The rules, with adequate experience, may be extended to the optimization of operations on a regional basis at all times of the year. The other requirement for successful operation would be to specify a neutral agency like the Power Grid Corporation as the operating agency, and indicate that all the surplus power would be taken into a notional pool. There would be a need for a regulatory body to oversee the operations at this stage.

As examined later it may be necessary to indicate to the national regulatory Board the areas of regulation by the regional regulatory Boards. Needless to say, the regulatory Board will only become operational when self-regulation by the REB is not able to solve the problem.

2.5 *Regulation and the need for restructuring*

The commercialization reform process of the SEBs can proceed smoothly only with requisite reforms to the regulatory process. The forms of regulation vary with the extent of market operations and commercialization prevailing in the electricity industry. One can therefore envisage two scenarios. The first scenario is the transition stage where more traditional regulatory mechanisms are inevitable. The second scenario is where discretionary regulation (arm's-length) or internalized regulatory mechanism come into use.

The nature of the regulatory agency comes into prominence, as this would determine the efficacy of arm's-length regulation, while also minimizing the scope for regulatory capture. The instruments of regulation are mainly price, subsidy, taxes, and, of course, the legal powers of a regulatory agency through licensing. Regulation can be broadly categorized into economic and social regulation. The main intention of economic regulation is: How to induce privately owned utilities to act in an optimal manner that is compatible with social goals? Optimality is usually defined as maximization of producers and consumers surplus. The main responsibilities of an efficient regulator are to:

- Promote competition
- Prevent noncompetitive behavior
- Regulate where monopoly elements prevail.

In recent times, environmental regulation has become very important. Operational and safety regulations form one dimension of social regulation. Regulation for commercialization is to ensure competition. The contradictory statement of 'regulation for competition' is an overriding concern during the period of transition. Entry regulation or deregulation is preeminent to simulate competitive conditions. By and large, competitive bidding of the franchise enables the government to select the bidder whose price is closest to long-run marginal cost.

There are two prerequisites to entry regulation. First, there should be a large number of bidders and there is no cartel among bidders or between the regulator and the entrant. Second, no one bidder should have privileged access to information. These conditions, however, do not yet prevail in India, partly because the central government is keen to clear projects due to the prevailing energy demand, and partly because the SEBs, the CEA, and the central government have not yet evolved the norms for ranking projects. In lieu of simulating competitive conditions, a distinction is drawn between 'purchase price' and consumer tariff. Regulation of 'purchase price' and consumer tariff have to be estimated, and sometimes negotiated by a neutral regulatory agency. Purchase price involves an incentive scheme that does not allow for capital waste.

Consumer tariffs are aimed mainly at two considerations. They are:

- Maximizing consumer surplus
- Flattening out peaks.

The prevailing practice of incorporating the distribution of equity should be divorced from tariffs of the electricity industry and be reverted to state fiscal policy. Purchase-price fixation and consumer-price fixation set by a regulatory agency has raised worries of regulatory capture. There are two ways of handling it. One way is to ensure a regulatory agency that has member representation of all stakeholders. It may be headed by a retired judge or an academician whose objectiveness is not questioned. Alternatively, attention has been drawn to schemes that operate in dual markets where captive and free sales of energy are combined. Private companies are free to sell power in the open market after meeting their contractual agreement with the SEBs. Private utilities ensure their returns through cross-subsidization between the two markets. Consumer prices can then be concentrated on the regulated markets only. This complements our earlier reforms.

Dual markets can succeed, provided the distribution of power is also commercialized. Regulation of operational and safety regulation to ensure the smooth operation of the grid, either by evening out peaks or by ranking the peaking facilities, may be necessary in the transitory period. External regulatory agencies have traditionally coordinated operational and safety regulation. Pricing schemes, to a certain extent, can be designed to prioritize grid operation. Safety regulation may require further clauses of tax restrictions. Social regulation or environment regulation, in recent times, has assumed importance. Of primary concern under environmental regulation is the problem caused by acid rain deposits from thermal power stations.

Regulatory agencies that set commission standards have been the basis, until now, of regulation with control methods derived from the threat of fines or even imprisonment. Even here, efforts should be made to internalize the costs to the environment through a method of regulation which is supplemented by economic incentives involving the use of 'tradeable permits'. The task of regulation is complicated by the asymmetry in information flows, inadequately defined property rights, and excessive transaction costs. Often, the debate on the privatization of utilities and regulation of utilities without introducing a new set of factors has often weighed the evidence in favor of public ownership. This scenario is different from industrialized countries such as the U.S. where public ownership in utilities is more the exception. Thus, we find in the regulatory systems of other countries, information flows are best left to the regulator.

In India, currently, the reverse situation prevails where the information flows are against the agent (the new private sector entrant). Unfortunately, this advantage has not been sufficiently appreciated to evolve sensitive regulatory norms. Similarly, transaction costs determine the choice between internal and external regulatory mechanisms. The governance of regulation in combination with transaction costs may often weigh in favor of simple mechanisms as compared to more complicated and sensitive regulatory schemes. The regulatory institution could be one at the national level and the others at the regional level. The national level regulatory body could be a part of the CEA, and could deal with entry regulation and regulation of the price of power from government generating plants.

3. Micro-level measures to improve the commerciality of SEBs

The suggestions for reform of the power sector are more clearly focussed at the micro-level. In this section, we have attempted to streamline the factors responsible for the financial viability of the SEBs. The reform measures suggested emerge from the analysis undertaken here.

3.1 Factors which contribute to financial viability

The factors which contribute to the financial soundness of the SEBs include:

- Efficient operational performance in technical, managerial, and commercial aspects
- Sound financial policies relating to capital structure and accounting policies, tariff policies, and the resulting tariff structures adopted by the SEBs' pricing of inputs
- Efficient investment choices to meet increasing demand and efficient implementation of capital projects.

The SEBs are statutorily required to earn a state government prescribed minimum rate of return of 3 percent on their net fixed assets, after fully meeting fixed and operating costs, depreciation, interest, reserves, and state electricity duty. The state governments could increase the minimum required rate of return to any value higher

than 3 percent (Section 59, E(S) Act). It is noteworthy that not a single state has increased the minimum rate of return. The very fact that the minimum surplus has been statutorily legislated indicates the government's appreciation of the need for the SEBs to operate as financially viable entities and to contribute towards future expansion programs. Barring a few exceptions, most SEBs have not been able to comply with this requirement. In fact, the average rate of return on capital, which was -16.4 percent in 1989-90, and -13.8 percent in 1990-91, further deteriorated to -17.3 percent in 1991-92. Furthermore, the SEBs have not been able to meet their commercial obligations to suppliers of inputs and equipment, and central sector power generating corporations from whom they purchase power. This has created major problems for the latter, who as a result, have been unable to fulfill the financial covenants for loans from multilateral/ international lending agencies.

All the states uniformly display negative profits (Table 2 and Annex 1B), even though the magnitude vary between states. The weak financial position of the SEBs gets reflected in their inability to meet debt servicing or debt redemption obligations, particularly to state governments. Some SEBs have not been able to provide for depreciation.

3.2 *Factors responsible for poor financial performance*

The causes of poor performance which are within the control of the SEBs are:

- Low generation output
- High T&D losses
- High establishment costs arising from excessive levels of manning, and ineffective management practices
- Poor revenue collections
- Overruns in completion of projects
- High operations and maintenance costs due to poor management of inventories, high consumption of secondary fuel, etc.
- Unremunerative tariff structures.

The following deals with some of the factors outlined above.

Low generation of output plant load factor (PLF) is an important indicator of the utilization of thermal power plants. The Rajadhyaksha Committee, set up in 1980, recommended an overall average PLF of 58 percent. On an average, the PLF decreased in 1992-93 to 48.3 percent. The mix of good performing SEBs from bad performance SEBs is evidenced in Annex 2. A point of interest is that the PLF of central sector and private sector plants has been higher than the national average, while the PLF of most SEBs' plants has been lower than the national average, although there have been noteworthy exceptions. Improvements in PLF can result in significant savings. At 1991-92 levels of generation and tariffs, it can be seen that a 1 percent improvement in PLF would mean an additional generation in the order of 3,800 million units and a sale of about 2,800 million units, resulting in an additional revenue of Rs. 280 crores. Furthermore, it would avoid an addition of installed capacity in the order of 790 MW, at a cost of over Rs. 1,600 crores[1]. PLF however, depends on a number of factors such as plant availability, availability of transmission facilities to evacuate the power, adequate fuel supply, system demand, the availability of alternate sources from which demand can be met. The multitude of factors make it difficult to pinpoint the main cause for low PLF. With continuous monitoring of PLF by the SEBs, efforts to rectify low PLF can be covered. Often, high availability and low PLF indicate a surplus situation or inadequate transmission facilities.

T&D losses are known to be a major factor of electricity availability. The Eighth Plan specifically has identified reducing T&D losses to 19.6 percent by 1996-97 from the current 22.9 percent. T&D losses increased from 17.6 percent in 1970-71 to 20.6 percent in 1980-81. By 1991-92, T&D losses increased to 22.9 percent (Table 4). The causes for T&D losses are technical as well as commercial. Technical factors include the extension of LT distribution network to cover increasing areas and low load densities with long lines. The major commercial factor for T&D losses is the system. Flat rate tariffs, instead of metered supplies, do not reflect the true level of consumption. Organized pilferage of power is another factor for high T&D losses. In the plan outlay (Eighth FYP), T&D was fixed at Rs. 22,281 crores of which states would account for 16,782 crores and the center for 4,437 crores. Over and above, allocation for T&D in the Eighth Plan has been about 36-37 percent of the total allocation, against a

[1] Government of India, Ministry of Energy, Report of the working group for suggesting steps for strengthening the Finances of State Electricity Boards (Chairmanship of K.P. Rao), May 1989, New Delhi.

Table 4
Transmission and distribution losses

Sl.	board	1989-90 (RE)	1990-91	1991-92	1992-93 (EST)
1.	Andhra Pradesh	20.1	19.9	19.3	19.0
2.	Assam	21.3	21.0	20.5	20.0
3.	Bihar	22.8	21.0	22.0	21.5
4.	Gujarat	22.1	22.1	21.7	21.4
5.	Haryana	24.5	26.4	24.5	23.5
6.	Himachal Pradesh	18.7	17.5	19.2	20.1
7.	J & K	49.5	56.7	49.7	45.0
8.	Karnataka	20.0	19.6	19.3	18.9
9.	Kerala	22.0	22.0	21.0	20.0
10.	Madhya Pradesh	19.5	24.2	23.2	22.7
11.	Maharashtra	17.6	15.5	15.5	15.4
12.	Meghalaya	10.9	13.0	13.3	12.2
13.	Orissa	24.0	24.0	23.0	23.0
14.	Punjab	19.0	19.0	18.8	18.6
15.	Rajasthan	22.0	24.9	22.5	22.0
16.	Tamil Nadu	18.5	18.4	18.4	17(.3)
17.	Uttar Pradesh	26.1	26.1	25.0	24.0
18.	West Bengal	22.6	22.0	21.5	21.0
All Boards' Average		**22.0**	**21.9**	**21.4**	**20.7**

Source: Same as Table 3.

requirement of about 40-41 percent. For various reasons, the actual investment in T&D has been well below the allocation.

The emphasis on rural electrification without appropriate investments in strengthening the supporting distribution and subtransmission systems is a major contributing factor to the problem. T&D losses could be reduced only by making adequate investments in the modernization of the distribution system and effective policing to prevent pilferage.

Manpower costs account for 20-25 percent of the cost of generation and supply of power. Invariably, the efficient SEBs have lower manpower costs. Also, lower manpower per unit, as can be seen in Annexes 3A and 3B, appear to be in excess of optimal levels.

In the last few years, attempts have been made to reduce the extent of overmanning and also to rationalize the use of manpower. Scope for further rationalization always exists.

RECOVERY OF REVENUE: Poor revenue collection has also been one of the factors contributing to the poor financial health of the SEBs. Normally, outstandings should not exceed 2 months revenue or 16.5 percent of sales. The all-India average was 24.46 percent at the end of 1983, 24.71 percent by the end of 1987, and 31 percent at the end of 1989 and 1990. In some Boards, O/S have exceeded 40 percent and sometimes exceeded 80 percent of annual sales such as Bihar and Meghalaya. Among the efficient states, Tamil Nadu has the highest recovery ratio[2] (See Annexes 4A and 4B). Poor collection of revenue is due to:

- Outstandings pertaining to other government departments—central and state, public sector organizations, local bodies, etc.
- Litigation against tariff revisions which impedes collection.
- Poor collection from agriculture in spite of low tariffs.

A multi-pronged approach needs to be adopted to improve the collections of the SEBs. A few suggested measures include:

- State government departments' dues can be adjusted against State Electricity duties collected, interest payable, etc. The state government, in turn, can debit the respective government departments. Central government should instruct its departments to pay promptly.
- Prompt rectification of billing discrepancies, and the treatment of billing disputes on the

[2] Ibid.

basis of an initial partial payment from the customer, pending final settlement, would improve the collections position.

- Litigation on tariff revisions should be kept out of purview of local courts. A tribunal should be set up to settle disputes promptly and give directions binding on both parties.
- Often the dues to the SEBs from sick industries which are being reconstructed are waived. This should not be resorted to when the SEB itself is making losses. If so, central/state governments should compensate the SEB.

OTHER FACTORS: In the final analysis, the efficiency of the SEBs can be improved through: improved management practices in the areas of inventory management, maintenance management, operations management with respect to auxiliary consumption and fuel consumption. Demand management would further improve the cost performance of the SEBs.

TARIFF REFORMS: Tariff reforms form the crux of commercialization of the SEBs. At present, the resort to noneconomic objectives in arriving at tariffs tend to affect the functioning of the SEBs, and also introduce distortions within the rest of the economy.

In Part 2 of this paper, the tariff setting process and its consequent impact on the SEBs and state governments were highlighted. In this section, we examine in further detail the tariff structure and the need for reform. Computation of tariffs should be such that the SEBs obtain a revenue which enables them to meet operating expenses, interest, depreciation, and taxes if any, and leave at least the minimum prescribed surplus. In practice, however, the tariffs have remained below the cost of generation and supply. It can be seen from Table 5 that the percentage gap between the average cost of generation and supply and the average realization, which was increasing until 1990-91, has shown a decreasing trend thereafter. This can be attributed to special initiatives taken by the various SEBs to reduce the gap through tariff increases.

These figures do not take into account provision for RE subsidy, because by and large, the subsidies have not been paid. In practice, subsidies are only transfers, and do not add to overall resource availability. The Table also shows that the average realization from agricultural consumers has been far below the average cost of generation and supply. The losses to the SEBs on account of unremunerative tariffs to the agricultural sector have been in the order of Rs. 5,000 crores to 5,500 crores annually, and are likely to cross Rs. 6,000 crores in future.

4. Transitional measures for immediate implementation

A complete commercialization of the power sector and SEBs, along the lines suggested, would take time to be fully implemented. Benefits accrue over time as and when the reforms initiated fruitify. In the intermediate or transition stage, certain immediate measures can

Table 5
Average cost vs average realization

	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	1991-92	1992-93
Average cost of generation & supply (p/kWh)	74.59	80.37	88.96	93.40	101.50	116.90	119.20	124.03
Average realization from all categories (p/kWh)	59.43	66.49	71.09	74.03	74.62	77.86	9.50	93.37
Gap (p/kWh)	15.16	13.88	17.87	20.17	26.88	39.04	29.70	30.66
Gap as % of cost	20.32	17.27	20.09	21.60	26.48	33.40	24.90	24.72
Average realization from agricultural consumers (p/kWh)	18.15	17.70	NA	NA	14.89	13.47	14.71	15.06

Source: Government of India, Ministry of Energy, Report of the Working Group for suggesting steps for strengthening the finances of SEBs, May 1989, New Delhi.

be taken up. These transitory reform measures involve:

- **Reconstitution of the SEBs:** Currently most of the board members of the SEBs are constituted with full-time members and ex-officio members from the government. There are very few SEBs which provide for membership to non-officials representing consumer interest. Wherever a public person has been nominated, he is usually a person with great political interest whose time and attention available for this work is limited. The immediate measure that will pave the way for further reforms is the reconstitution of the electricity boards with at least two members representing consumer interest and one, a nominee of the funding agency. That would leave four members to be filled by other full-time members of the Board or ex-officio nominees.
- **Brief for the member representing the financial institution:** The member representing financial institutions should be given a clear brief that he press for the completion of accounts and collection of LT arrears. While the tariff is low in respect of several categories, it is unfortunate that collection is greatly in arrears even with regard to LT consumers. Arrears of LT to some extent create financial problems for the Boards.
- **Agricultural tariff:** The GOI issued instructions that the agricultural tariff in all the states be fixed at a minimum of 0.50 ps. per kWh. As all the states have been having tariffs of less than 0.50 ps., there is an attempt on the part of the SEBs to raise tariffs uniformly since the measurement of actual power consumed by meter reading is a very tedious task. Moreso, since the meters are yet to be installed in most of the places. Even if they have been installed, they are located in far away fields where there will be no person to open the pump shed and allow the meters to be read. It is, therefore, necessary that some arrangement of nurturing the total power consumed from the size of the pump installed should be arrived at. It would be appropriate if the SEBs start negotiating with organizations representing the agricultural consumers of power, to arrive at feasible consumption norms. If this is not acceptable, and agricultural consumers are not willing to negotiate, SEBs may appoint judicial bodies to arrive at a decision. The regional tariff commission for power which has been set up may take a long time to come into effect and, thus, at each stage, individual state level initiatives are required.
- **Improving system load:** Several measures were identified for increasing the power factor. It is better that a drive is undertaken to persuade the consumers to install capacitors, as required by the electricity Boards. This would immediately bring down the demand on the system.
- **Flattening of peaks:** SEBs should immediately undertake some work to improve the supply of power between different states within a region to take advantage of the daily peak load. The introduction of time of the day metering can be done for large industrial loads, or the tariff for the night load can be reduced. If these measures are initiated at once, it would create the necessary ambience for the pursuit of other reforms.

Annex 1A

Commercial profit/losses (-) at current rates (excluding subsidies) during the Seventh Plan (1985-90 period) (Rs. crores)

Sl.	Board	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
1.	Andhra Pradesh	-9.65	-53.87	7.86	8.36	-54.36	-101.66
2.	Assam	-107.31	-122.83	-134.42	-168.44	-217.44	-750.44
3.	Bihar	-191.73	-224.93	-293.85	-218.24	-283.10	-1,211.85
4.	Gujarat	-123.00	-87.43	-167.57	-190.81	-383.57	-952.46
5.	Haryana	-78.03	-94.58	-110.33	-79.58	-193.45	-555.97
6.	Himachal Pradesh	-22.70	-28.02	-50.15	-50.13	-50.87	-201.87
7.	J & K	-40.66	-49.66	-68.32	-73.62	-103.21	-335.53
8.	Karnataka Board	-26.78	-74.59	-104.64	-50.70	-98.43	-355.14
9.	K.P.C	-50.93	-75.93	-85.13	-67.61	-103.15	-382.75
10.	Kerala	4.83	-16.34	-48.19	-43.70	-16.18	-119.58
11.	Madhya Pradesh	-21.11	-42.48	-7.34	-78.98	-9.41	-32.14
12.	Maharashtra	-57.43	54.00	47.31	-192.58	-339.10	-487.80
13.	Meghalaya	-3.28	-10.12	-4.49	-10.99	-15.63	-44.51
14.	Orissa	-22.70	-18.61	-63.81	-70.50	-8.65	-184.27
15.	Punjab	-144.97	-216.03	-345.17	-425.69	-564.15	-1,696.01
16.	Rajasthan	-60.57	-58.80	-135.87	-121.17	-199.89	-576.30
17.	Tamil Nadu	-182.86	-145.47	-223.42	-396.16	-493.30	-1,442.21
18.	Uttar Pradesh	-325.28	-343.22	-399.63	-543.17	-708.02	-2,319.32
19.	West Bengal	-92.87	-84.59	-121.51	-144.46	-172.06	-615.49
Total		**-1,514.89**	**-1,608.54**	**-2,308.67**	**-2,918.23**	**-4,014.97**	**-12,365.30**

Source: Government of India, Power and Energy Division, Annual Report on Working of SEBs and Electricity Departments (EDs), August 1992.

Annex 1B

Commercial profit/losses at current rates (excluding subsidies) for 1990-91 to 1992-93 (Rs. crores)

Sl.	Board	1990-91	1991-92	1992-93
1.	Andhra Pradesh	-17.23	59.15	112.81
2.	Assam	-242.04	-292.50	-261.56
3.	Bihar	-344.23	-365.36	-370.71
4.	Gujarat	-442.72	-581.38	-594.84
5.	Haryana	-155.20	-285.82	-361.25
6.	Himachal Pradesh	-19.62	-59.77	-71.83
7.	J & K	-151.36	-217.10	-244.10
8.	Karnataka Board	-14.43	-86.41	-257.17
9.	K.P.C	-38.98	36.83	19.96
10.	Kerala	-52.51	-69.06	3.02
11.	Madhya Pradesh	-302.66	-261.65	-366.37
12.	Maharashtra	-4.10	-167.47	203.64
13.	Meghalaya	-22.90	-27.57	-21.95
14.	Orissa	21.51	-6.70	0.19
15.	Punjab	-573.45	-561.70	-748.69
16.	Rajasthan	-210.59	-118.70	-300.83
17.	Tamil Nadu	-369.15	-432.19	-753.26
18.	Uttar Pradesh	-657.73	-873.50	-949.94
19.	West Bengal	-229.00	-186.45	-157.37
Total		**-3,748.36**	**-4,498.27**	**-5,120.60**

Source: Government of India, Power and Energy Division, Annual Report on Working of SEBs and Electricity Departments (EDs), August 1992.

Annex 2
Annual PLF of thermal stations

Sl. agency SEBs/region	*1980-81*	*1984-85*	*1985-86*	*1986-87*	*1987-88*	*1988-90*	*1989-90*	*1990-91*	*1991-92*
1. Haryana	31.7	34.7	32.8	33.8	40.6	41.2	44.1	34.6	45.9
2. Punjab	37.8	64.3	58.7	68.3	71.7	56.1	60.8	53.0	52.8
3. Rajasthan	—	57.2	57.6	54.8	71.5	50.2	57.7	62.8	66.3
4. Uttar Pradesh	36.5	31.6	37.3	40.8	47.1	54.2	48.9	52.1	44.4
Northern Region	**40.9**	**47.5**	**48.9**	**52.8**	**58.3**	**58.2**	**58.2**	**55.3**	**58.0**
5. Gujarat	50.0	54.0	53.3	54.0	60.0	56.1	60.4	57.7	57.0
6. Maharashtra	52.0	46.6	54.8	50.7	57.0	53.5	58.6	58.2	61.3
7. Madhya Pradesh	52.4	51.7	53.3	53.8	53.3	50.1	50.9	52.7	49.1
Western Region	**53.1**	**53.0**	**55.8**	**55.4**	**59.8**	**56.6**	**60.3**	**57.7**	**59.6**
8. Andhra Pradesh	36.3	54.4	64.8	69.7	76.2	69.4	66.1	65.8	62.1
9. Tamil Nadu	34.5	49.0	56.5	64.7	68.7	66.7	64.3	58.3	55.4
10. Karnataka	—	—	33.5	45.6	64.5	66.2	76.9	76.3	59.1
Southern Region	**41.4**	57.0	**64.6**	**69.5**	**71.8**	**69.3**	**66.6**	**61.7**	**60.8**
11. Bihar	31.4	30.5	34.1	33.3	33.0	37.1	31.9	24.0	21.3
12. Orissa	34.0	32.2	31.7	31.7	32.5	31.0	35.6	34.0	30.2
13. West Bengal	42.1	36.5	40.5	42.1	38.6	35.7	34.8	30.9	30.7
Eastern Region	**38.1**	**40.8**	**42.0**	**40.1**	**38.7**	**38.6**	**38.7**	**36.5**	**37.3**
14. Assam	36.5	29.6	27.5	18.5	31.0	27.9	27.8	27.7	24.7
NE Region	**36.5**	**29.6**	**27.5**	**18.5**	**31.0**	**27.9**	**27.8**	**27.7**	**24.7**
All SEBs	**42.7**	**44.8**	**49.2**	**49.8**	**53.5**	**51.6**	**53.0**	**51.3**	**50.6**

Source: Government of India, Power and Energy Division, Annual Report on Working of SEB and EDs, August 1992

Annex 3A
Employees per '000 consumers

SEB	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
Andhra Pradesh	14.3	12.8	11.9	11.0	10.3	10.4
Assam	66.2	61.0	62.2	55.0	55.2	42.7
Bihar	39.5	37.8	35.5	33.3	33.1	32.9
Gujarat	10.4	10.1	9.9	9.4	9.5	9.5
Haryana	21.1	20.1	19.0	18.4	18.1	17.7
Himachal	15.3	14.8	13.5	13.0	13.3	12.7
J & K	25.6	29.6	25.8	26.7	27.6	27.6
Karnataka Board	'1.3	10.7	10.3	10.0	9.7	8.1
Kerala	,1.4	9.9	8.8	10.1	10.1	10.1
Madhya Pradesh	21.5	19.7	19.2	18.5	18.5	18.5
Maharashtra	17.5	16.0	15.0	14.9	13.7	13.7
Meghalaya	70.6	65.8	63.4	59.6	62.9	56.3
Orissa	43.6	42.7	40.8	40.1	40.2	40.2
Punjab	20.7	19.7	19.8	19.5	18.6	18.2
Rajasthan	28.0	26.2	24.5	23.9	21.4	20.0
Tamil Nadu	15.2	15.1	14.5	13.1	12.3	11.8
Uttar Pradesh	35.2	33.4	31.3	29.1	26.1	23.2
West Bengal	45.5	43.4	37.8	34.0	30.2	27.3
All boards average	**20.0**	**18.9**	**17.9**	**17.1**	**16.3**	**15.7**
ED's average	**23.3**	**23.3**	**22.1**	**21.3**	**20.2**	**19.7**

Source: Government of India, Ministry of Energy, Report of the Working Group for suggesting steps for strengthening the finances of SEBs, May 1989, New Delhi.

Annex 3B
Employees per MU sold

SEB	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
Andhra Pradesh	5.3	4.9	5.2	4.7	4.4	4.0
Assam	18.7	17.1	17.9	16.2	14.9	15.0
Bihar	11.3	11.0	9.7	8.5	7.5	7.6
Gujarat	4.2	3.8	3.2	3.1	2.8	2.5
Haryana	8.6	8.1	7.5	7.0	7.1	6.7
Himachal Pradesh	13.5	12.5	10.2	9.3	9.7	7.1
J & K	12.5	13.5	11.7	12.9	11.6	13.5
Karnataka Board	6.6	6.5	6.5	5.8	3.9	3.5
Kerala	6.5	6.9	6.7	6.8	6.2	5.6
Madhya Pradesh	6.8	6.3	6.5	7.3	7.0	6.0
Maharashtra	4.6	4.3	4.1	4.3	3.9	3.8
Meghalaya	11.0	14.1	9.5	10.8	12.4	15.4
Orissa	10.1	8.8	8.0	8.0	7.9	7.2
Punjab	8.0	7.0	6.7	6.5	5.6	5.4
Rajasthan	11.8	10.0	9.5	8.4	7.6	7.2
Tamil Nadu	8.6	7.7	7.8	6.6	6.4	5.8
Uttar Pradesh	8.1	7.2	6.8	6.3	5.6	5.1
West Bengal	10.9	10.4	9.2	8.5	8.1	7.9
All Boards average	**7.3**	**6.7**	**6.4**	**5.8**	**5.7**	**5.2**
ED's average	**9.2**	**9.1**	**8.5**	**8.1**	**7.3**	**5.7**

Source: Government of India, Ministry of Energy, Report of the Working Group for suggesting steps for strengthening the finances of SEBs, May 1989, New Delhi.

Annex 4A
Revenue arrears of the SEBs

SEB	As at end of 1984-85		As at end of 1988-89		As at end of 1989-90	
	Amount Rs. Cr.	% of sales	Amount Rs. Cr.	% of sales	Amount Rs. Cr.	% of sales
Andhra Pradesh	100.0	20.0	166.0	21.0	265.0	26.4
Assam	15.0	25.0	30.0	24.0	33.0	24.5
Bihar	163.0	71.0	337.0	68.0	403.0	82.4
Gujarat	86.0	14.0	124.0	12.0	124.0	12.0
Haryana	43.0	25.0	174.0	51.0	23.6	67.2
Himachal	8.0	29.0	41.0	49.0	67.0	48.0
J & K	—	—	24.0	51.0	24.0	51.0
Karnataka Board	111.0	33.0	361.0	56.0	315.0	43.2
Kerala	40.0	31.0	46.0	20.0	51.0	18.2
Madhya Pradesh	125.0	25.0	470.0	51.0	595.0	57.9
Maharashtra	182.0	21.0	432.0	22.0	594.0	22.0
Meghalaya	14.0	93.0	18.0	93.0	17.0	94.4
Orissa	54.0	37.0	120.0	45.0	143.0	46.7
Punjab	36.0	14.0	83.0	16.0	91.0	15.6
Rajasthan	65.0	29.0	116.0	21.0	135.0	22.1
Tamil Nadu	54.0	10.0	51.0	6.0	47.0	4.4
Uttar Pradesh	204.0	34.0	434.0	43.0	608.0	47.0
West Bengal	45.0	21.0	140.0	30.0	160.0	29.8
All Boards	**1,345.0**	**25.0**	**3,167.0**	**31.0**	**3,690.0**	**30.7**

Annex 4B
Financial performance of the SEBs

Performance parameter	1989-90	1990-91	1991-92	1992-93
1. PLF %	53.00	51.30	50.60	48.30
2. T&D losses %	22.00	21.90	21.40	22.90
3. Total sales (BU)	162.27	176.35	187.19	204.37
4. Average realization through energy sales (paise/kWh)	74.62	77.86	89.50	93.37
5. Average cost of generation and supply (paise/kWh)	116.90	119.20	124.03	
6. Average realization from non-agri, non-domestic consumers (paise/kWh)	127.85	138.30		
7. Average realization from agri. consumers (paise/kWh)	14.89	13.47	14.71	15.06
8. Sales to agri consumers (BU)	42.03	48.81	51.93	55.38
9. Loss of revenue due to sale to agri. Consumers (Rs. Crores) (Item 8*(Item 5 - Item 7)	5,048.21	5,426.58	6,035.19	
10. Sales to domestic consumers (BU)	24.67	26.3	29.78	
11. Loss of revenue due to sales to domestic consumers (Rs. Crore)	821.00	1,056.00	1,301.01	1,565.20
12. Revenue receipts (Rs. Crore) (from all sources)	15,324.11	17,733.34	20,672.57	
13. Commercial profits/losses (Rs. Crores) Excl. RE Subsidies	-4,014.97	-3,748.36	-4,498.27	-5,120.60
14. Additional resource mobilized (Rs. Crore)	3,338.96	957.62	2,205.80	1,232.09
15. Internal resource mobilized (Rs. Crore)	-1,387.39	-1,723.78	-1,717.55	-2,251.16

An approach for trading in the Indian power system

by
Powergrid Corporation of India Ltd.

1. Introduction

"Electricity" is a concurrent subject in India; i.e., it is the responsibility of both central government and state governments. Due to diversity of resources in various states/regions, the Indian power sector is quite a complex system. The Indian power sector has been developed on the regional concept of power planning and the country was demarcated into five regions: northern, eastern, northeastern, southern, and western. It includes a large number of central agencies that are superimposed on the state power sector. The Central Electricity Authority (CEA) is responsible for the formulation of the national power policy, overall planning, and coordinating power development at the national level. The State Electricity Boards (SEBs) are responsible for promoting coordinated development at the state level for generation, transmission, and distribution of power. The Regional Electricity Boards (REBs) coordinate and formulate policies and guidelines for integrated operation of the regional power grids.

Further, there are some private power generating and distribution companies like Ahmedabad Electricity Supply Company, Tata Electric Company, Calcutta Electric Supply Company, etc. In August 1991, the Government of India made an important policy decision to encourage private sector companies, both Indian and overseas, to invest in the electricity sector, either on their own or in joint venture as independent power producers (IPPs). In addition, there are nonconventional energy sources (NCESs) such as solar, geothermal systems, wind energy systems, mini/micro hydel projects, biogas plants, etc., which have immense potential to bridge the energy gap on a long-term basis.

Though rapid strides have been made in manifold increase of generation capacity in the post-independence era (from 1,300 MW to the present level of 72,319 MW), the power sector has been unable to supply quality and reliable power, and demand is continuously outstripping supply. Currently, energy shortages on all-India basis is about 10 percent and peak deficit is about 19 percent. The total demand for electricity is likely to grow at the rate of 8 percent per annum. This is bound to be reflected in continued shortages of power in different

regions of the country and would further constrain economic and particularly industrial development. The Eighth Five Year Plan period (years 1992-97) envisages an addition of about 30,000 MW of new generation capacity including generation from IPPs along with associated transmission and distribution facilities. However, due to resource constraints faced by Central Power Sector Undertakings (CPSUs), as well as SEBs with no budgetary support available from the government, the actual capacity addition may be about 15,000 to 20,000 MW only. Further, the paucity of funds will delay setting up of long gestation period, hydrostations adding further to the existing imbalance in hydro-thermal mix.

While on one hand, demand for power is continually exceeding the supply, backing down of generation to the tune of 9,700 GWh in 1991-92 and 8,600 GWh in 1992-93 actually took place, which is most undesirable. This results in the uneconomic utilization of generating plants which continue to operate and waste fuel while water is being spilled at hydrostations, particularly during off-peak periods.

2. Status of interregional exchange of power

As a result of the changing supply and demand scenarios in different regions, the pattern of interregional flow of power has undergone a change (Table 1). The interdependence among various states and regions has also been witnessed (Table 2). For example, the northern region was exporting around 585 GWh of energy to other regions in the years 1979-80. A decade later, the net imports in this region were as high as 342 GWh and in year 1992-93 the net export was 432 GWh (Table 3). During the year 1978-79, net imports in the case of the western region were 481 GWh. On the other hand, by 1989-90, this region was exporting around 950 GWh to the neighboring regions. During 1992-93, the region imported 472 GWh during the year but was net exporter of 281 GWh. Similarly, the southern region, which was exporting energy until the early 1980s, became a net importer of energy in 1989-90 and in 1992-93, its net import was 243 GWh. In the case of the eastern region, the net imports which were of the order of 290 GWh in 1979-80 gradually increased to 1,856 GWh by 1989-90 and in year 1992-93, it was net importer of 412 GWh. The northeastern region continued to be a net exporter of energy during the last decades.

Table 1
Interregional power exchange

Year	*GWh*
1988-89	2,042
1989-90	2,146
1989-90	1,864
1991-92	2,345
1992-93	1,748

Table 2
Interstate/system energy exchange

Year	*GWh*
1988-89	5,800
1989-90	6,330
1990-91	4,166
1991-92	4,380
1992-93	3,588

Table 3
Net export (import) of energy (GWh)

Region	*1988-89*	*1989-90*	*1990-91*	*1991-92*	*1992-93*
Northern region	260	234	565	946	432
Eastern region	(283)	(333)	(923)	(823)	(412)
Northeastern region	—	—	—	(51)	(57)
Southern region	(1,259)	(1,009)	(499)	(187)	(244)
Western region	1,282	1,108	857	120	281

3. Constraints in the Indian power system for trading of power

Ideally, each of the regional power systems should operate in a coordinated way. However, even though the operational plans are deliberated by the SEBs within their REB for the following day/month, the same are not fully coordinated and actual operations vary in different degrees. Various constraints which come in the way of the minimum level of coordination required for integrated operation for power trading can be classified in the following categories:

3.1 *Infrastructural constraints*

BIAS TOWARDS SHORT-TERM GOALS: The regional pattern of power development has led to imbalances in the hydro-thermal mix. As against the desired hydro-thermal mix of 40:60 to provide peaking support and prevent suboptimal level operation of thermal plants during off-peak hours, the ratio is, today, 28:72 on all-India basis. Hydro resources, which are unevenly distributed in various regions, could not be optimally harnessed due to resource constraints, long gestation period of projects, and other bottlenecks. In spite of the culture of centralized planning, there has been a strong tendency to achieve short-term goals instead of going in for integrated long-term development. Thus, even though advance planning was done in the Seventh Plan for the succeeding Eighth Plan for taking up various schemes, particularly hydro schemes, due to the paucity of funds, the hydrothermal mix continued to shift in favor of thermal generation and to the gas-based thermal plants having much shorter gestation periods (2 to 3 years).

MISSING TRANSMISSION LINKS: It is to be emphasized that there is a need to avoid the temptation to let transmission and distribution (T&D) outlays slip. As a result of continued neglect of the transmission and distribution sector over the last two decades, there are now serious problems in the transfer of power and also high distribution losses. Little attention has been paid to strengthen the regional grids by providing missing transmission links and interregional ties for adequate exchange of power between different regions. There are substantial quantums of energy resources which remain unutilized over the year in different regions, as at certain times of the day/season, generating stations in one region have to be backed down while simultaneously, there is perceptible power shortage in the neighboring region (Table 4). The establishment of these interregional links needs to be taken on priority basis to ensure considerable economies in power generation as well as increased power availabilities. The distribution system is to be strengthened to a high level of voltage up to 6.6/11 KV instead of 440 V to reduce technical losses (at present 5 percent), distribution losses (at present 18 percent), and theft of power in both urban and rural areas.

Table 4
Backing down of generation (GWh)

Region	*1990-91*	*1991-92*	*1992-93*
Northern region	4,559	3,644	2,676
Eastern region	74	213	----
Northeastern region	----	----	----
Southern region	393	1,068	265
Western region	8,438	4,779	5,699
Total	13,458	9,704	8,640

It has been estimated that in the year 1996-97, in the eastern region, total energy to be backed down will be about 16 GWh during maximum thermal day and 17 GWh during maximum hydel day. Similarly, for the western region, the respective values are 12 GWh and 19 GWh. With the overall energy shortages in one region and surplus in another region, which we are currently facing, the situation is utmost undesirable. Installation of interregional links will lead to additional energy generation of about 6,500-6,700 GWh through improved hydro-thermal mix of combined regions.

LACK OF COMMUNICATION FACILITIES: Focus on the development of load dispatch and communication facilities has been minimal and there is almost everywhere a serious lack of communication facilities between the control centers and the power plants which has resulted in inadequate monitoring and control of the complex power system. Presently, most of the system data is being acquired manually through power line

carrier communications and telephones, telex, etc., which is grossly inadequate to assist the load dispatchers in ensuring healthy and effective operation of the integrated power system. Lack of appropriate communication systems results in a large number of grid collapses, long system restoration time, and unscheduled flow of power from one state to another.

DEFICIENCIES IN METERING FACILITIES: At present, energy accounting is done every month based only on manual readings of energy meters at each end of the inter-system tie lines. Time-of-day (TOD) energy accounting in the present day system is not possible. Most of the systems lack adequate metering and instrumentation facilities. These include, besides normal indicating and recording, energy meters of the requisite accuracy and capabilities; disturbance recorders; sequential event recorders, etc., which are essential for real-time monitoring of the system and efficient accounting system for power exchanges. Input data and information from these instruments are also vital for diagnosis and analysis of major events and grid disturbance.

FINANCIAL CONSTRAINTS: In view of the present budgetary constraints, government is finding it extremely difficult to provide budgetary resource for funding vital infrastructural sector schemes. In the Eighth Five Year Plan (year 1992-97), the capacity addition required was 38,000 MW for which minimum Plan allocation of Rs. 120,000 crores was considered necessary. Against this, the outlay for the power sector is only about Rs. 80,000 crores with the targeted capacity of about 30,500 MW. As such, the power sector has been opened up for private sector participation, and all possible efforts are being made to attract private capital to support the efforts being made by the resource-starved CPSUs and SEBs for meeting this target. Efforts are also on to commercialize the PSUs and the SEBs with a view to increase their internal resource generation for further reinvestment in the sector.

There are however, few vital areas which require massive induction of capital for building basic infrastructure facilities like interregional links and system control and coordination framework which will, in the long run, facilitate optimal utilization of generating resources while meeting the energy requirements of the growing economy. On a rough estimate, it will cost approximately Rs. 5,000 to 6,000 crores for building these facilities in the next 8-10 years which will facilitate exploitation of energy resources in the most optimal locations and meeting the demand of widely spread load centers across the country with reliability, security, and economy.

Considering the present financial status of SEBs, it is difficult to imagine how most of them will be in a position to bear the additional burden of capital servicing cost of such facilities if the same are to be built by raising resources from the financial market and charging full commercial tariff to start with, as is presently envisaged. Considering the vital necessity of building these facilities without any delay, it is imperative that we explore the possibilities of reducing the burden of capital servicing cost on the already financially squeezed SEBs by finding out some via media. One of the ways this could perhaps be achieved is by providing some element of budgetary support, supplemented with initial subsidy for a period of about 5-10 years on the capital servicing cost of these facilities, while the SEBs and the power sector are being restructured to bear the full commercial cost of all the facilities in the long run. While this budgetary support and initial capital servicing cost subsidy may look large in the financial terms; in economic terms, these facilities will have a pay back period of hardly 2-3 years each. Extending such limited budgetary support and financial subsidies will not be a burden as a whole on the nation and will go in a long way in the optimal integrated development of the power sector for fulfilling the vital needs of the growing economy. The study conducted by the World Bank in 1991 on "Long-Term Issues in the Indian Power Sector" indicates that interlinking of regional grids could reduce the unserved energy demand by 50 percent and accrue benefits of Rs. 1,100 crores per year. Studies conducted by CEA in 1991 on the perspective plan of "National Power Development up to 2006-7" also reveals that interregional links will save about 10,000 MW power generation capacities by the end of the Tenth Plan.

3.2 *Operational constraints*

The regional grids suffer from very serious problems such as wide frequency and voltage fluctuations, frequent grid disturbances, lack of grid discipline, uneconomic operation, etc. In our system, load changes dictate the system frequency and generators are unable to control frequency because of low reserves and energy shortages forcing utilities to serve as many

consumers as possible at a given time. Voltage fluctuations take place not only on a seasonal basis, but also on daily basis. During light load conditions, the voltage level is in the order of 420-430 KV whereas in the peak load conditions, the voltage dips to as low as 320 KV on 400 KV buses, causing serious grid disturbances.

The reasons for this type of system behavior is attributable to inadequate reactive compensation at all voltage levels especially at the subtransmission and distribution network. The lack of proper agreements spelling out the reliability criteria, obligations of suppliers, and beneficiaries are other deficiencies in the system for operational discipline. As of now, generation units are generally reluctant to back down even during off-peak time as the generation incentive is linked to PLF. Similarly, an SEB will not buy power from the other efficient (lower marginal cost) generating stations as the purchasing price, as per present tariff arrangement, is higher than the marginal cost of its own generation. There are no means of enforcing operational discipline. In the case of a state drawing more than its allotted share of power, the Regional Load Dispatch Center (RLDC) can, at the most, request the erring state to regulate its demand, and in most of the cases, the response from the state is only partial. The continual overdrawing of power by deficient states at the peak time, while the same states do not back down during off-peak hours as the frequency becomes very high, is testimonial to the grid problems. The prevailing accounting system based on monthly energy readings with no TOD metering have no financial repercussions on erring states. Most generating units operate on constant load mode with turbine governors made virtually inoperative. As such, they neither participate in frequency control nor do they respond to load fluctuations. The basic reason for operating on constant load mode is that frequency fluctuation are too wide (48 Hz to 51.5 Hz) and any generating unit, if left on normal free governor mode, would suffer violent load changes and premature equipment failure.

3.3 *Institutional constraints*

COMMERCIAL ARRANGEMENTS: The existing commercial arrangements between the generating and transmission utilities and SEBs are based on the tariffs specified in the MOUs on a regional basis. All the exchange transactions are based on simplistic flat paise/kWh in which the rate neither changes with time of the day (peak load hour/off-peak hour) or existing system conditions (generation deficit/surplus), nor changes with the extent of drawal. Commercial arrangements seldom reflect marginal cost as tariff rates are set at average total cost and, while making dispatch decisions, SEBs compare these average rates with the marginal costs of operating their own plants which distort operating decisions. There is no provision for enforcing the agreed conditions in the MOUs to discourage overdrawal by SEBs, particularly during peak hours, nor to induce power plants to back down during off-peak hours. The generators ignore back down requests but still charge for unwanted energy and conversely, no penalty is imposed on SEBs which exceed their generation shares. MOUs do not provide for trading of the SEBs' share of generation. Energy is traded under ad hoc arrangements rarely related to marginal costs without appropriate division of benefits between exporters and importers. There is no financial compensation to any party for over-stressing its power plants for assisting the system during contingencies nor do they discourage MVAR drawal from EHV grid.

UNREMUNERATIVE TARIFF STRUCTURE: The problems are further compounded by the structure of tariff charged by SEBs to the consumers and subsidies provided to certain categories of consumers and tariff for bulk power supply from the CPSUs to SEBs. Consumer tariffs are by and large decided by the respective state governments. SEBs have been directed to supply power to certain categories of consumers, particularly agricultural and domestic consumers, at highly unremunerative rates. While some of the state governments compensate SEBs through subsidy, most of the other state governments do not, thus pushing the SEBs into incurring huge losses. As per the Electricity (Supply) Act, 1948, SEBs are required to adjust their tariffs, so as to ensure the total revenue in any year on the amount of sale after meeting expenses, leave such surplus not less than 3 percent or such higher percentage as the state governments may specify of the value of fixed assets in service at the beginning of such financing year. SEBs are not given a free hand to fix their tariffs in a manner to comply with statutory obligation, nor are they fully compensated by the state governments for subsidizing a particular section of consumers. Further, there are no laid down operating parameters to keep a check on SEBs' operational efficiency and make them accountable for any shortfall on this account.

The structure of tariffs charged by the SEBs to the consumers are not based on commercial and scientific consideration which should reflect the cost of supply and be conducive to energy conservation and optimal utilization of electricity resources. A particular case is the "fixed charge tariff" charged by most of the SEBs from the agricultural consumers accounting for 28 percent of power consumption for their agricultural pumpsets based on the rating of their installation (per bhp/kW). These consumers are not levied any charges on their energy consumption and have no electricity meters at their premises leading to wasteful use of electrical energy and aggravating energy shortages.

Presently, CPSUs are supplying power to the SEBs based on a flat rate tariff (paise/kWh). Even the interstate exchanges of power, as well as interregional exchanges of power, are taking place on a per unit charge basis causing distortions in the electricity generation based on merit-order operations of the power plants. Thus, even the pithead stations owned by the CPSUs are asked to back down in spite of having a lower short-run marginal cost, while generation continues at load center stations having higher short-run marginal cost. Recently, government has taken a decision to introduce a two-part tariff system for bulk power for National Thermal Power Corporation's (NTPC) coal-based thermal power stations based on K.P. Rao Committee recommendations (June 1990). Under the system, the fixed cost of the power station is charged to the beneficiaries in proportion to the actual energy drawn and the variable cost is charged separately for the actual energy consumed by the respective beneficiaries. The power station will be reimbursed 100 percent of the fixed cost on achieving the targeted plant load factor (6,000 hours per annum - 68 percent PLF) and for operation beyond this target, incentive is given as a part of the variable cost on a sliding scale with incentive going up per percentage point increase in the PLF above the target level. This is an important step towards introduction of a rational tariff structure for bulk power. A number of further steps are required for making the bulk power tariff structure rational for facilitating development of a bulk power market as well as to pave the way for optimum system operation.

Unremunerative tariffs result in the lack of merit-order operation of the power stations leading to poor financial performance of the SEBs. Poor financial performance of SEBs also has a cascading effect on the financial health of the central electricity generation and transmission PSUs. In case bulk power as well as retail tariffs are set on sound commercial principles, merit-order operation of generating units will be ensured for overall economy. Further, the SEBs will earn reasonable returns, thereby being in a better position to provide reliable power supply to the consumers to their satisfaction. For the year 1992-93, average unit cost and revenue in states was 141 paise/kWh and 106 paise/kWh, respectively, resulting in a negative rate of return of 12.9 percent, negative internal resources of Rs. 175 crores, and total commercial loss of Rs. 500 crores. The unremunerative tariff and the subsidies provided by SEBs have not only affected the financial health of central electricity generation and transmission PSUs, but have also put a strain on the already resource-starved power sector.

4. Concept of power pooling

The concept of power pooling as applicable in the country implies that each SEB would be responsible for supplying the load on its system. Each SEB would do this either by using its generated power or power purchased from central sector utilities, other SEBs or private generators and trading power in accordance with agreements made with these parties and the grid code (operating rules of the pool).

For a coordinated and integrated operation of the power system, at the outset, it is critical to form a clear proposal on the operational arrangements for scheduling and dispatch and to build commercial procedures and signals to support those arrangements. This is a prerequisite for trading of power between the utilities. The trading system constituting a power pool should provide financial incentives for utilities to operate their plant in a way which minimizes overall supply costs to the benefit of end consumers. In India, with the division of responsibility for power supply between the center and the states, and presence of central government and state-owned utilities, the 'loose power pool' model is an appropriate mechanism for system operations. The "loose pool" concept is built on a presumption of a high degree of autonomy in scheduling and dispatch for the participating utilities. The goal is always to design procedures and pricing

arrangements which induce members to trade electricity (to buy and sell) when it is economic to do so, both for their own and in the system's perspective.

The purest form of "loose pool" involves trade among vertically integrated utilities. The utilities here are responsible for scheduling and dispatching of their own plant to meet their demand and can elect to buy or sell under the terms of the pooling mechanism. The pricing rules which determine the payments made for such trades, encourage utilities to trade in preference to generating from a more expensive plant of their own. This pure model is ideal to accommodate the mixture of vertically integrated SEBs and central generating companies as well as new private generators (IPPs). In the event all SEBs decide to have their plants dispatched by REB, the pool would in one sense become "tight"; i.e., having an established arrangement for joint planning on a single system basis, and provision for centralized dispatch of generating facilities with contractual agreements of specific financial penalties in the event the contractual agreement relating to all generation capacity and margins are not met. The advantage of "loose" pools in the Indian environment will be that SEBs can retain considerable commercial independence while participating in their regional pool to the extent most appropriate to each Board's balance of economic, social and other operational objectives. However, pool members have to adhere to certain fundamental rules (grid code) of operation which are essential for maintaining the technical integrity of the system and that pool members do not involuntarily incur cost as a result of action by another pool member. In addition, states could retain their existing responsibilities for the development of their power sector. Since the pool will be a voluntary cooperation of public and private utilities, each member of the pool will benefit from the association.

5. Present status regarding power pooling

At present, the country's generation resources are owned and operated by a mix of central agencies, SEBs, and private organizations. SEBs are responsible for servicing load in their territory. Central generating units are responsible for generating power within the region and their capacities are allocated on a firm basis to the various beneficiary states within the region based upon the Gadgil formula. Private generators presently meet requirements confined to their existing states or for their own requirement. Distribution is done by SEBs, except in the case of a few private organizations. In the northern region, interstate exchanges of energy are priced at a global rate (fixed cost plus variable cost of load center) and net trades are settled at the end of each month. In the western region, the philosophy is more towards independent operation by the SEBs with trading limited to surplus after meeting the state's own requirements. Here, trading is largely on ad hoc basis and prices reflect the costs of central generation more closely than to system marginal cost. In the southern region, region-wide shortages of energy provide very few opportunities for coordinated dispatch. Operations are highly constrained by required releases of water for irrigation which takes preference in multipurpose schemes and then scheduling priority of a limited amount of thermal plant to conserve stored hydro energy for the dry season. The regional power pools will be ideal functioning markets for surplus generation. As capacity may continue to be a constraint, most of the trading within a region will be confined to off-peak periods for some time. However, due to differences in times of high demand in different regions, the western region can provide substantial energy to meet the demand of the southern region. As capacity constraints ease, trading within the regions could also get enhanced during intermediate and peak demands. However, for interstate power exchanges, today, neither tariff nor agreements are well defined, treatment of overdrawal or underdrawal begs commercial principles. There is no single point of responsibility for reliable system operations.

6. Role of Powergrid - coordination for power pooling

Powergrid will promote the creation of regional power pools in all regions, on a voluntary cooperation basis of public and private utilities including alternative nonconventional energy

systems for benefits of the members. Powergrid will be in charge of operating the Regional System Coordination Centers (RSCCs), the decision for which is already taken by the government, to provide economy and reliability with generation dispatch and transmission operation closely coordinated. With adequate communication and control facilities in RSCCs, Powergrid will manage operations of the loose power pools, while members will continue to have basic responsibility for operating their plants and serving their consumers, but coordinating many of their activities for mutual benefits, voluntarily and effectively. The pooling arrangement will allow SEBs on their own to coordinate their activities to produce economic and reliability benefits which all could share. SEBs can agree on short-term and long-term energy transactions, with those parties which have low incremental cost surpluses selling them to others, who can thereby avoid generating from sources with higher incremental cost at mutually agreed prices beneficial to both the parties. These transactions will also aid SEBs to perform maintenance at a convenient time as well as in the purchase of power from the utility having lower cost surplus capacity during the prolonged gestation period of construction of new stations. SEBs can be of mutual assistance to each other in the case of outage of major units or spinning reserves may be shared by neighboring systems.

Powergrid will coordinate closely the generation dispatch and transmission to optimize operation of total power system. As an operator of power pools, Powergrid will provide information on available capacity, energy to members for their needs and a price range; a forum for coordinating generation maintenance schedules; monitor tie-line flows for ensuring system reliability and informing the parties accordingly; deviations from agreed transactions; information for raising bills and settlement, etc. This system will ensure the most economic generation of power based on commercial principles. States will be able to contract for a specific type and quantum of power and will be free to contract the cheapest power. This will also help the generating organizations in the optimum utilization of their capacities.

6.1 *Scheduling and dispatch arrangements*

The REBs are presently responsible for scheduling and dispatching the regional electric system which includes maintenance schedules, setting of tariffs for interagency power transfer, billing, etc. Consistent with the need to preserve the commercial and operational freedom of SEBs to retain responsibility for scheduling and dispatching their own plants within the "loose pool" arrangement, a decision is required on how to treat plants owned by central generating companies. There are few options which need careful consideration on this aspect.

- ***Responsibility for scheduling and dispatching the plants could rest with companies themselves:*** In this case, the companies would participate directly in trading through the power pooling arrangements. The central generating organizations would enter bilateral contracts to sell capacity and energy to SEBs and themselves decide whether to generate to fulfill those contracts or whether instead to purchase energy more cheaply on the day from other generators (including the SEBs also).
- ***Responsibility for scheduling and dispatching the plants could rest with the concerned SEBs:*** In this case, the SEBs would specify the physical energy requirement from the plant with which they have "contracted" and require the plant to operate at that level. With capacity and energy "allocated" or "contracted" to more than one SEB, the final dispatched output from the plant should be the sum of all SEBs requirements. If all SEBs act to minimize costs, the plant should only be dispatched if it falls within the national "merit order", so long as SEBs are purchasing on a two-part, capacity and energy charge. Failure to meet the requested load would trigger availability penalties in the form of reductions in capacity charge payments by the relevant SEBs.
- ***Responsibility for scheduling and dispatching the plants could rest with Powergrid:*** This would be a mixture of "loose" and "tight" dispatching and pooling arrangements. While each SEB would dispatch its own plant, it would be for Powergrid to determine the total output of the central generators and each of the SEBs portfolio of plant—on the basis of information about the cost of each central plant and the cost at the margin of each SEBs generation subsystem.

Thus an appropriate balance between the independence of SEB dispatching, decisions and

optimal use of central generating stations would be a key area in the design of the pooling arrangement.

6.2 *Inter-utility trading*

In this regard, the role of Powergrid is of vital nature for the power sector as it will want to act as administrator rather than as principal in the energy transactions, for reasons of credit risk and avoidance of overly central control. The broad spectrum of roles that Powergrid can take for operating loose power pools as facilitator/ clearing house for power trading between the states to enhance the interstate cooperation for commercial power exchange arrangements are as follows:

PURELY ADMINISTRATIVE: Here, Powergrid would simply provide a financial settlement service and it would be for the SEBs to seek out and agree to bilateral transactions. A form of price declaration process will be provided within the 'loose pool' whereby each SEB can elect to declare a price at which it is willing to buy/sell energy. It will be left to the SEB, on the basis of bids, to determine bilateral arrangements, with rules for determining the trading price specified and agreed in advance. Powergrid will play no role in determining the transactions to take place.

"POWER BROKER" ROLE: In this case, Powergrid will act as recipient of all of the SEBs price declarations and will determine the pattern of bilateral transactions to take place, the basis of which will be established and agreed by all parties including the SEBs.

In either of the options, Powergrid will entail to resolve the following issues:

- Inadvertent trade, i.e., problems of SEBs taking more power than had been pre-contracted especially during times of shortages and causing interstate disputes. Powergrid will bring out the pricing mechanism which will charge such transactions at their full value to deter deliberate power diversion or through physical network control.
- "Free-riding" viz. no participant can gain access to long-term energy supplies through the mechanism without paying the full cost of both capacity and energy on the system.
- "Losses" treatment in the power system which would be consistent with bulk power and transmission pricing proposals as Powergrid will eventually be assuming integrated national dispatch function.
- "Transmission constraints" will be assessed and their effect in the pooling arrangements will also be taken into account in bulk power and transmission pricing proposals as the energy transactions will be limited and affected by actual or potential power flow constraints on the system.
- "Grid support services" will be provided and proposed arrangements for operational and financial treatment of grid system services will be clearly specified.

7. Why power trading?

Until a few years ago, trading of electric power had not been an issue in India. All ultimate consumers of electricity in India were, and still are, being served by their respective SEBs, Electricity Departments, private licensees, etc., and their relationship is primarily that of captive customers versus monopoly suppliers. Even the relationship between the SEBs and the central generating companies/jointly owned projects has basically been similar, with each SEB having an allocated share in all such generation, and being expected to draw its allocated share, without really bothering about the price. In other words, the suppliers of electricity have had little choice about whom to sell their product to, and the buyers had no choice about whom to purchase their requirements from. The prices are primarily being fixed and controlled by the central and state governments.

Trading inherently means a transaction where the price is negotiable and options exist about whom to trade with and for what quantum, to obtain the best bargain. Power trading will allow utilities to use the most economical energy available in the system, and through pooled operation, more power will be derived from the integrated resources than if each entity operated on its own. The basic essentials for economy transactions are the available capacity and different generating costs of various sources of power. If available capacity is limited, then there will be little opportunity to buy or sell energy regardless of price. In addition, if an energy production cost differential does not

exist, there would be no economic incentive to make transaction regardless of the amount of available capacity. In India, all the five regions are in deficit in meeting the peak load requirements, whereas there have been substantial quantums of energy resources which remain unutilized over the year in different regions at certain times of the day and season. Generating stations in one region often have to be backed down while simultaneously there is perceptible power shortage in the neighboring region. Installation of interregional links will improve the hydro-thermal mix of combined regions, and by transmitting the surplus energy of the eastern and western energy to the northern and southern regions, we can have better utilization of existing resources.

7.1 Advantages of trading

RELIABILITY: The consumer demands and has a right to expect a continuous supply of power to meet his different needs. A utility's primary function is to meet this demand and to ensure its reliability. An individual system, unconnected with neighboring systems, could find its resources depleted and continuous supply in jeopardy as is the case in most of the SEBs when maintenance of the system, excessive peak demand, and loss of generation all occur at the same time. However, operating, as a single system, the regions and SEBs can rely on the capacity of the transmission ties between each other, and pool to provide the surplus power to meet the continuous demand with increased reliability of supply.

ECONOMY: The coordinated scheduling of generation in the pool to meet the expected combined peak demand allows for planned operation of the least expensive generation irrespective of location within the pool. In addition, the surplus capacity can be shared over the entire system, thus avoiding the necessity of generating units running at higher marginal cost for its own security. Sharing of resources will also result in reduction of both operating costs and capital expenditures.

8. Proposed approach for power trading

Almost all SEBs today have a shortage of generating capacity to meet their peak demands and, consequently, have had little surplus to offer for trading with their neighbors. The lack of requisite transmission links in some cases, and absence of the requisite commercial mechanism, have further prevented electricity trading between the SEBs, even when the off-peak surplus of one SEB could be taken by a needy neighbor. The situation is now changing in many ways. While peak-hour shortages may continue, and there may be very little surplus from round-the-clock capacity available for trading, there is a big scope for off-peak trading between the SEBs, both intraregional and interregional. It would basically entail utilizing the differential between their respective incremental costs, and optimum utilization of their hydroelectric resources.

8.1 Illustrative example

Let us consider what should ideally be happening through the following simple illustrative example. SEB-A and SEB-B each have an installed generating capacity of 1,000 MW of their own, and 25 percent shares in a 2,000 MW central generating station (pit-head) in the region. The peak demand of each SEB's consumers is 1,200 MW, and the off-peak load is 700 MW. If the central plant has a capability of delivering 1,600 MW (ex-busbars) on a particular day, the entitlement of each SEB on that day would be 400 MW. Assuming that this pit-head power has a lower incremental cost (say 30 paise/kWh) than all of SEBs' own generation, each SEB should endeavor to draw 400 MW from the grid throughout the day. The SEBs can do this by regulating their own generating stations such that their total generation is 400 MW lower than the total load of their respective consumers. In turn this would mean that the SEBs have to reduce their own generation to only 300 MW during the off-peak hours, and raise it to 800 MW during peak load hours.

Suppose 300 MW out of SEB-A's installed capacity is hydroelectric (storage type), which would straight away be backed down during off-peak hours. Even then, the SEB would have a surplus (thermal) capacity of 200 MW during the off-peak hours, presuming that SEB-A has the requisite plant availability (800 MW) to meet its obligations on that day. SEB-A can offer this off-peak surplus of 200 MW to SEB-B, and the latter could accept it, if it can use it to replace costlier generation, or if it has a shortage during those hours.

Suppose the above 200 MW (which SEB-A would have to otherwise back down during the night) has an actual incremental (fuel) cost of 60 paise/kWh. Suppose SEB-B is so placed during those off-peak hours that it can meet its obligations from cheaper sources except for the last 100 MW, which has to come from load-center capacity having an actual incremental cost of 70 paise/kWh. In such a case, the two SEBs should ideally agree for supply of 100 MW from SEB-A to SEB-B at a mid-way price of 65 paise/kWh, so that both derive equal benefits from such a transaction.

For the above transaction to be mutually beneficial and equitable, both the quantum and price have to be determined judiciously. Also, the two have to be determined simultaneously, considering the incremental costs of the two parties, for the various slabs of generation. For example, SEB-A above has an incremental cost of 60 paise/kWh for the 200 MW surplus whereas SEB-B has an incremental cost of 70 paise/kWh for 100 MW and perhaps 56 paise/kWh for the next 200 MW. In such a case, if SEB-A supplied more than 100 MW to SEB-B, 60 paise energy would be replacing 56 paise energy, which would be meaningless.

8.2 *Correctness of data*

The success of any such trading depends on the correctness of data. For example, if SEB-A deliberately declares its incremental cost as 64 paise/kWh and demands the sale price to be fixed at 67 paise/kWh, it could pocket a bigger share of the trading benefit than rightfully due to it. An SEB may also fail to make the best use of the trading opportunity if it does not have correct and up-to-date information about the status and incremental costs of its plants in operation.

One must also appreciate that the above is not a one-time exercise. It has to be done again and again, typically every hour, as the generation-load balance keeps changing. For example, SEB-A may have agreed to supply 100 MW to SEB-B at 65 paise/kWh up to 6 a.m., based on the respective incremental cost of 60 and 70 paise/kWh. Now suppose SEB-B had to take out a 100 MW unit with an incremental cost of 56 paise due to some problem at 3 a.m., and the 100 MW unit with 70 paise/kWh incremental cost (which had been backed down consequent to the deal with SEB-A) was run up again. In this new situation, SEB-B would perhaps be replacing 100 MW of 80 paise/kWh generation by the 100 MW it is receiving from SEB-A. The new price should therefore be fixed at 70 paise/kWh instead of the 65 paise agreed earlier. This is possible only if SEB-B faithfully reports such a development (for upward revision of its purchase price), or if there is an overall monitoring mechanism.

In a multi-utility system, the above negotiations become so involved that extensive computations become essential. These are generally centralized at power pool control centers.

8.3 *Maintaining net interchange as per schedule*

The next basic requirement is that each SEB must maintain its actual net interchange as per schedule. For example, in the above illustration, SEB-A should be getting 400 MW of its central generation share, and should be supplying 100 MW to SEB-B (during off-peak hours); in effect SEB-A should have a net drawal of 300 MW from the grid. On the other hand, scheduled interchange of SEB-B would be 500 MW during these hours. As mentioned earlier, this calls for a continuous regulation of own generation for absorbing the own-load changes. For this, each SEB must have full-fledged load dispatch and communication facilities, to (1) get all tie-line flows, to determine the SEB's actual net drawal from the grid, and (2) send commands to all of its major generating stations to maintain a generation-load balance such that any difference between actual net drawal from the grid and the schedule is brought back to zero. All this has to be done almost on a minute-by-minute basis, and in a manner that it simultaneously conforms to economic dispatch, or merit-order according to incremental costs.

8.4 *Operational discipline*

The above calls for an operational discipline. Basically, it means that no SEB should unilaterally decide to deviate from its net interchange schedule. For example, when SEB-B was forced to take out its 100 MW unit of 56 paise/kWh incremental cost, it could have simply not run up a costlier generating unit. In such a case, SEB-B would have developed a deficit, which would have come automatically from the grid. In effect, its net drawal would have increased from 500 MW to 600 MW. Most likely, this additional 100 MW would have come from the idling surplus of SEB-A, without any agreement about its supply or price. Such deviations from schedules are not permissible, except for short durations (in which the defaulting SEB must correct the situation). Ideally, SEB-B must either run up its own generation to meet the deficit, or negotiate an additional purchase duly identifying the quantum and price. In Western countries, any such inadvertent (short-time) deviations from scheduled interchanges have to be made up in kind, by correspondingly adjusting the future schedules.

8.5 *Ideal working requirements for interconnections*

What has been described above is the ideal way of the working of interconnections, generally according to the concepts universally adopted in the developed countries. The underlying assumptions and requirements are:

1. The SEBs' shares in central and jointly-owned power plants are identified in hourly energy or MW, not just in monthly or daily energy.
2. The load-dispatch center of each SEB has a full, up-to-the-minute picture of the SEB's complete system, particularly regarding incremental costs, spinning reserve, etc., of its generating units in operation and on standby.
3. Chief load dispatcher of each SEB has the requisite authority to negotiate over telephone the quantum and price of such trading with his counterparts, and is willing to take crucial on-the-spot decisions having a high monetary value.
4. There is adequate transparency and/or faith between the SEBs such that incremental costs of available/avoided generation as stated by one SEB are accepted by others.
5. Each SEB has full-fledged load-dispatch and communication facilities, for continuous monitoring of its actual interchange, and for on-line regulation of its generating units to minimize deviations from its interchange schedule.
6. A mechanism exists for determining hourly deviation from the net interchange schedule for each SEB, and then either attaching a monetary value to it or making a compensatory adjustment in future schedules.
7. There is willingness on the part of all SEBs to maintain their drawals from the grid as per schedule, even during conditions of generation shortage. They should be willing to buy the required capacity/energy from their neighbors through advance negotiations, in case their own central generation share is insufficient to meet their consumers' total demand, and they should have the capability to pay a reasonable price for the same.

Unfortunately, not even one of the above assumptions would be valid in India today. While considerable discussions may succeed in bringing about (1), (3), (4), and (7), the facilities required for (2), (5), and (6) simply do not exist in most of the SEBs and may take another 6-7 years to get established. Without these facilities, the SEBs simply cannot control their net drawals from the grid, and maintain them as per any given schedule. This is the basic point that we all must appreciate. All Western theories based on a tight control of net interchanges therefore cannot be applied in India, for the next 6-7 years at least. Further, all deviations from schedules across the board cannot be penalized just because they are perceived as an indiscipline from the Western point of view. Due to the requisite facilities being absent, even a disciplined SEB cannot comply with this requirement.

Another problem is that incremental costs do not figure at all in the present interutility tariffs. While the actual incremental cost of a central pit-head station may be 30 paise/kWh, the incremental cost for that power, as seen by the SEBs, may be 60 paise/kWh. The result is that SEBs insist on backing down of central pit-head stations along with their own load center stations. In this situation, the SEB does not even know what its correct incremental cost is: 30 paise or 60 paise? And what benefits of trading between SEBs can be thought of, when the SEBs are being deprived of full benefits of

their own central pit-head share? In such a situation, trading has to be based on a different concept altogether.

8.6 Identification of hourly drawal schedule

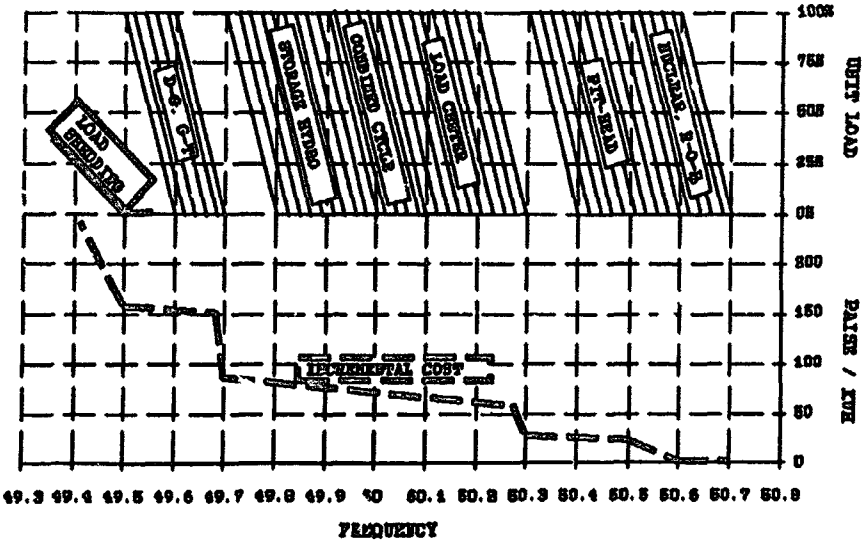
The starting point for negotiating any power trading between two SEBs is identification of their hourly drawal schedules from central and joint projects. In the scheme that Powergrid is proposing, each central and jointly-owned power plant would have to advise its expected MW and energy availability for the next day. Based on their respective shares in these power plants, all SEBs would then have to indicate how they propose to draw their shares over the next day. For example, if a hydroelectric plant is expected to have enough machine and water availability to generate up to 100 MW and 1,000 MWh the next day, an SEB having 50 percent share in the plant would be entitled to draw 500 MWh, with a peak of 50 MW. As such, the SEB may specify that it would draw 25 MW from 6 am to 4 pm and 50 MW from 4 pm to 9 pm. Summation of such schedules for all central and jointly-owned stations shall become the datum interchange schedules for the respective SEBs, and would provide the first prerequisite for trading.

8.7 Frequency-linked load dispatch guidelines

Since most of the SEBs today do not have the required load dispatch and communications facilities, frequency-linked load dispatch guidelines can be used as an interim measure, primarily for achieving region-wide economy dispatch (merit-order generation) during the next 6-7 years. In this scheme, the frequency thresholds up to which different types of generating units should work at full load, and thereafter how they should back down, would be specified. *A typical guideline would be as shown in Figure 1.* Once such a guideline is given to and adopted by all power plants, a definite relationship will get established between the grid frequency and the system-wide incremental cost, as shown. It will then not be necessary for load dispatchers to continuously communicate with their various power plants for obtaining their status, incremental costs, etc. Just by looking at their frequency meter, they should be able to know their own current incremental cost, largely meeting the second requirement for trading.

Further, since the incremental cost vs. frequency relationship would be identical for all SEBs, everybody can reasonably be assumed to be having the same incremental cost at a particular time, such that the transparency is automatic, and no negotiations between load dispatchers are necessary regarding fixation of transaction price, substantially meeting the intents of the third and fourth requirements listed above. All short-term, as-and-when-available exchanges, unless otherwise agreed between the concerned SEBs, can simply be priced

Figure 1
Typical frequency-linked load dispatch guideline



according to the predefined frequency-based incremental cost.

Not only this, lack of or gaps in the required load dispatch and communication facilities would no longer be a bottleneck for trading, in the sense that actual interchanges could be allowed to deviate from the schedules, and the fifth requirement would no longer be a constraint, as explained below.

The whole concept of interconnected operation as practiced in developed countries is fundamentally based on the premise that each control area (which has to be clearly identified in advance) shall regulate its actual net interchange and keep it as close to its interchange schedule as practicable. There are two basic reasons for this. Firstly, unless each control area closely regulates its net interchange, the overall frequency regulation would not be possible, particularly in the large, multi-area interconnections. And a very stable frequency is essential for applying the concepts of tie line bias, etc. Secondly, pricing of deviations from interchange schedules (termed as unscheduled interchanges) is a problem. Mostly, these are not given a price tag at all, and are required to be returned in kind.

8.8 Need for adopting a pragmatic approach

In view of our present limitations and ground realities in India, Powergrid is proposing a departure from the above concepts. We know from our past experience that system operation is not adversely effected in any manner in case the frequency deviates by up to +/-0.5 Hz from the rated value of 50 Hz. We intend to permit this. There should be no difficulty in reconciling to this when we have been used to +/-2 Hz variation over the past 10-15 years. Tie line bias, etc., are still too advanced for us, and are even otherwise only theoretical until the full-fledged load dispatch and communication facilities become operational, hopefully by the year 2000. Once you are not sticky about the frequency, you also do not have to be too fussy about unscheduled interchanges. We intend to permit, recognize, and price these. Once we are adopting the frequency-linked load dispatch guidelines and are allowing the frequency to modulate, it is only logical to price the unscheduled interchanges (or all deviations from interchange schedules) as per the same frequency-based incremental cost.

8.9 Time of the day special energy meters

As for the sixth requirement, Powergrid has already done considerable work on development of requisite special energy meters. Such meters would have to be installed on all interutility ties to record energy flows for every 15-minute time block. If the SEBs give a go-ahead, Powergrid can immediately take up procurement action, and get them installed on all interutility ties in all five power regions within a year or so.

Further, once we are not intending to minimize the unscheduled interchanges, and are also not contemplating their return in kind, it is no longer critical to have the required measurements and telemetering for on-line indication of each SEB's actual net interchange. It is thus possible to apply the whole scheme as soon as we can get the special energy meters installed on all interutility ties, without waiting for anything else.

As for the seventh requirement, the SEBs' overall willingness to maintain their drawals as per schedules is desirable, but is not critical. As mentioned earlier, deviations from schedules would be permissible, but will be appropriately priced: at pit-head incremental rate of about 30 paise/kWh when frequency is above 50.3 Hz, at load-center incremental rate of about 60 paise/kWh when frequency is in 49.7-50.3 Hz range, and at diesel-generator incremental rate of about 150 paise/kWh when frequency is below 49.7 Hz. Overdrawal during peak-load hours would thus be discouraged, while overdrawal during off-peak hours would be encouraged.

Paying capability of the SEBs is, however, a serious matter, since the concept is based on financial disincentive for overdrawal during a deficit situation. This disincentive would become ineffective if an SEB can get away when it does not pay for the energy drawn from the grid. Timely payment of dues by all SEBs has, in any case, to be ensured, for the very survival of the Indian power sector.

8.10 Interchanges and trading modes

In the overall scheme being proposed by Powergrid, interchanges and trading would take place in the following modes:

1. Supply of allocated shares to all SEBs from the central and jointly-owned power plants. Such power plants would have to indicate

their MW and energy availability on a day-to-day basis, and the SEBs would have to specify how they propose to draw their respective shares over the next day. SEBs would pay a capacity charge (at a pre-calculated rupees per MW per day) rate for the MW availability forecast, and an energy charge (fuel/variable cost) for the drawal schedule advised by the SEB.

2. If an SEB does not need its share in a central plant as per the prevalent formula, it would be allowed to transfer or forego its share in full or in part, at its own option. Any such foregone share would be offered to the other beneficiaries, first in the same ratio as per prevalent formula, and then on a first-come, first-served basis.
3. The SEBs would be allowed to similarly contract with each other and with any private generators, identifying the daily drawal schedules and the price to be paid through a two-part tariff, duly identifying the capacity and energy charges.
4. The constituents of a regional pool would also be freely allowed to enter into long-/short-term agreements with each other for as-and-when-available energy, or for off-peak energy on a regular basis (duly identifying the drawal schedule) on a negotiated price basis.
5. The regional power pools could also negotiate interchanges/trading with neighboring regions on behalf of the member SEBs, duly identifying the drawal schedules, SEBs capacity, and energy shares, etc. Similarly, a consortium of certain SEBs could negotiate long-term/short-term contracts with neighboring countries as well.

The only restriction for the above modes of interchanges/trading would be a check from transmission constraints angle. As long as no segment of the transmission system of Powergrid or a third agency is over-stressed, there would be no bar on any such bilateral transaction.

Besides such scheduled interchanges and trading, the Powergrid scheme would provide a vast scope for unscheduled (but desirable) interchanges of as-and-when-available energy. So much so, that pool members may even prefer to supply/receive as-and-when-available energy as unscheduled interchange (at the frequency-governed price) rather than bother to negotiate the appropriate quantum and price in advance with a neighbor. Such interchanges would in effect be unscheduled exchanges with the power pool, the summation of which would be zero.

8.11 Non-utility generation

Non-utility generation (NUG) is the next area for which the Powergrid scheme provides a solution. India already has many thousands of MW of captive generation in industrial plants, but the same is not being integrated with the grid because of present frequency fluctuations and due to the absence of a proper commercial mechanism. Powergrid already has a comprehensive scheme for tackling the frequency problem. On the commercial side, any NUG injection into the grid would be priced as per the forementioned frequency linked rate. What the NUG injects into the grid can be left entirely to be decided by the NUG. It would mean that all NUGs having a fuel cost less than the declared diesel generator incremental cost (which would include a wear and tear element) would have an incentive to inject all their surplus capacity into the grid during peak load (generation deficit) hours.

A recent study has brought out that sugar industry itself can provide 3,500 MW of cogeneration provided we have a commercial mechanism in place for properly pricing its injection into the grid. Overall, adoption of the Powergrid scheme may therefore be sufficient to overcome a substantial part of the present power shortages. At the same time, there would be no incentive to NUGs to inject costly power during off-peak hours and raise the frequency. And the whole system would operate without any on-line communication between the load dispatch centers and NUGs. It was mentioned earlier that for any trading, quantum and price have to be agreed to in advance. NUGs are posing a challenge even in the U.S.A. in this regard, because it is difficult to communicate with every NUG, on-line, to find out what surplus he has available and how his cost compares with the utility's current incremental cost. The utility cannot decide how much power to take from which NUG, in the absence of the above data. Their frequency remains so constant that it can give no signal to either the utility or the NUG.

In India, as it happens, we are not tied down to a constant frequency thinking. So we can as well allow the frequency to modulate and provide the signal for streamlining our system operation, pricing of NUG, pricing of deviations

from schedules, encouraging trading of as-and-when-available energy, inducing efficiency and availability improvement, etc.

9. Dovetailing private sector and alternative energy sources

In the recent past, government announced a policy decision of allowing private sector participation, in power generation and distribution so as to bring in additional resources as well as expectations of bringing competition for increased efficiency in power sector operation. Keeping in view that private/joint venture generating companies will be entering soon into the arena, it is suggested that power generated from such ventures should be dovetailed into the overall planning of the transmission system envisaged by SEBs and Powergrid. The generating plants should be of optimum size to ensure that economies of scale can be achieved and location of the power stations should be based on economic criteria only. In the case of small size private generating stations where the power is to be fully absorbed within the state system and the generation is not likely to have significant impact on the tie-line flows of the regional grid, the power evacuation system will normally comprise of a few links within the state grid and the same should be designed in association with the concerned SEB. However, in the cases where significant size of generating plants are being planned, the power evacuation system of the same has to be planned in an effective and reliable manner. The evacuation system is to be properly dovetailed within the regional power grid to not only ensure proper dispersal of power generated from such stations, but also to keep the same within the safe and reliable operation limits of the grid. The state and regional system coordination facilities have to be, accordingly, properly enhanced to take care of reliable and economic operation in the integrated power system.

To speed up development of nonconventional energy sources (NCESs), it should be made mandatory for SEBs to purchase power from small power producers using alternative energy technologies and high efficiency cogeneration units through a special regulatory act. However, the price of power purchased by the SEBs should be just and reasonable, in the public interest. It should be, at least, priced equal to the cost that the utility would have incurred to generate the same power and sell the output to other utilities or customers through their transmission system to encourage innovative developments and promotion of energy conservation. The Public Utility Regulatory Policies Act is a similar type of regulation which is already in practice in the U.S.A. to promote alternative sources of energy.

10. Regulatory body

There is a need for the establishment of an independent regulatory body for the power sector on the line of Federal Energy Regulatory Commission, U.S.A., which could regulate private, state, and central generating, transmission, and distribution projects; endorsement of bulk power and transmission tariffs; establishment of standards and inspection, and audit of compliance of such laid-down statutory provisions besides playing a catalytic role in planning of the Indian power system at apex level.

Keeping in view the fact that CEA has been playing a key role in planning of the Indian power system and is fully equipped with knowledge and expertise about the sector, it will be only appropriate to restructure it into an autonomous regulatory body. This will require provision of an independent funding mechanism possibly by an appropriate levy on regulated entities and having ability to independently recruit and administer staff and to procure facilities and technical assistance to carry out its functions. While doing so it has to be ensured that CEA is not involved in the day-to-day operation of the power system in any manner to ensure its independence and unbiased character. In order to service widely dispersed areas, it will be appropriate that CEA have its own offices in each power region to cater to the regulatory requirements appropriately.

As a regulatory body in the power sector, CEA should be responsible for the following aspects:

- Planning regulation
- Tariff regulation
- Operating regulation
- Arbitration.

10.1 *Planning regulation*

CEA should continue to play the catalytic role in the national level planning. However, the planning process should shift focus on "indicative planning" instead of the current emphasis on "command-and-control" planning. This implies that it should provide the broad signals on anticipated demand, capacity needs, time frames, and other constraints and bottlenecks, but leaving exclusively to the various players in the sector to select their means to meet the planning goals and markets. It should be contrasted to detailed "command and control" planning which attempts to debate the exact means by which these goals should be met.

10.2 *Tariff regulation*

CEA should be vested with exclusive jurisdiction and autonomous character to review and develop tariff policies for bulk power and transmission tariffs to various power entities. It should be also empowered to develop statutory principles, methodologies to implement and enforce general principles and guidelines in the public interest. CEA should continue to review and approve cost-based tariffs for a) all central sector generating entities; b) interchange tariff between SEBs and private utilities; c) all private generating tariffs (IPPs); and d) transmission/ wheeling services to be provided by Powergrid and other entities ("unbundling" services) for long-term power interchange transactions to safeguard the interest of various entities, as well as ensuring the most efficient utilization of resources to develop an efficient bulk power market.

CEA should regulate pricing for transmission services and assurance of reasonable rights to transmission service for generators to reach the bulk power market as and when they evolve. CEA should have a provision for enforcing clear legal obligations to all the national providers of transmission services and all SEBs, other licensee utilities with the transmission systems that interconnect with the transmission grid to provide wheeling services in the most equitable and efficient basis, subject to the constraint of CEA's administered planning process.

10.3 *Operating regulation*

In this area, CEA's role should be purely advisory in nature for the long-term economic health of the power sector, as per the current proposed structure of RLDCs operating as a part of Powergrid with respective operation of the regional system and dispatch. However, Powergrid should provide all the necessary inputs on operational developments on a regular basis which are of importance to CEA for ensuring the technical stability and reliability of regional grids on merit order dispatch. Since Powergrid will be operating the RSCCs in the near future, it should develop, for each region, clear operating principles, standards, and procedures for maintaining reliability of the power system within the broad national policy framework.

10.4 *Arbitration*

CEA should be the only body to enforce commercial arrangements between the generators, SEBs and other entities to implement the proposed regulatory scheme and to build the necessary cooperative spirit among various entities in the operation and planning of the regional system.

In the case of disputes among different entities in the power sector, in the first instance, all efforts should be made by the concerned parties to try to resolve the disputes amicably through discussions. However, in case they are unable to arrive at a satisfactorily acceptable resolution, the case could possibly be referred for formal arbitration to CEA. The decisions of CEA should be final and binding among all parties. As a matter of principle, there should be no appeal for the CEA decision; however, where very significant issues of law or the Constitution is involved, then only CEA should permit a review of the decision at the apex court level (Supreme Court).

11. Proposed unbundling of Indian power system

The Indian power sector has been operating on the regional concept of power planning with development through SEBs, which were originally established in the vertically integrated model (generation, transmission, and distribution assigned to a single body). But as the demand grew and other hydro, solid fuel, gas resources, etc., were identified, a large number of new organizations were set up with specific responsibilities and functions such as NTPC, National Hydroelectric Power Corporation, North Eastern Electric Power Corporation, Neyveli Lignite

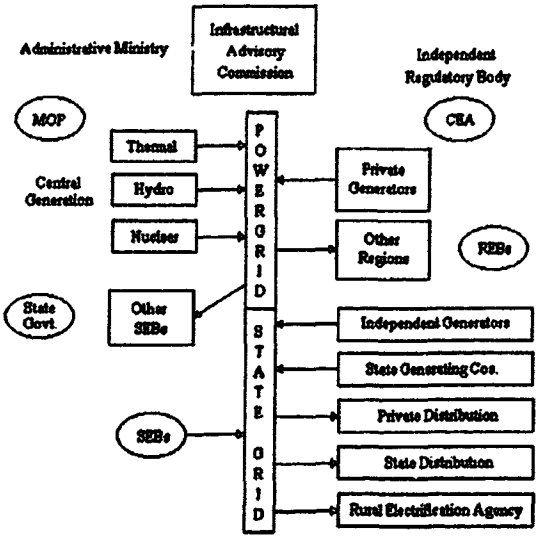
Corporation, Nuclear Power Corporation, etc., making additional alternative sources of generation available to SEBs. The formation of Powergrid for transmission activities represents another step in the restructuring the power sector in India. The process received further fillip by encouraging the private sector to construct and operate as IPPs. Keeping in view the trend that the Indian power sector is witnessing in unbundling the central power sector entities to introduce some form of competition and to become more market oriented, the following organizational structure for enhancing the operational efficiency and management of the power system is proposed (Figure 2).

The process of unbundling of the power system has been initiated in the central sector and the same has to be carried through in the state sector for realizing the full potential and benefits of the same. It will be worthwhile considering segregation of SEB activities into generation, transmission, and distribution as independent divisions/entities. State-owned generation could be supplemented by promoting IPPs either at the state level connected to the state grid or at the regional level connected through the Powergrid-owned regional network. The distribution system owned by the state could possibly be considered for restructuring into area distribution companies and could possibly be made to compete with private distribution companies which are likely to enter, though in a small way initially, in some of the major commercial centers. The transmission part of SEBs should work in tandem with Powergrid with mandatory wheeling of power for all the generating organizations including the private sector and CPSUs. This will then ensure optimum system design and efficient, secure, economic, and reliable transmission of power. This would also help in optimizing the investment required for development of the transmission system in the power sector for the nation as a whole. This will also bring in competition between the generators and also in distribution which, at present, is under the SEBs' ambit. The private sector entry in distribution will make it much more flexible and can bring in spot, medium- or long-term trade of power. The reforms will also allow generators, in the short term, the option of trade of surplus power to the various utilities.

There should be a separate organization to construct and operate the rural electrification system equipped with adequate capital and an appropriate capital structure to fulfill the social obligation for providing the minimum lighting needs to the poor rural households and supply power for irrigation at affordable rates. The necessary subsidies should be provided by the state government through their budget as is being done in the case of welfare schemes for education, family planning, and other poverty alleviation programs.

CEA, as a proposed independent regulatory body, will be responsible for regulating the entire power system as described above. Keeping in view the importance of the energy

Figure 2
Unbundling of the power system



sector in the economic development of the country, it is worthwhile to consider appointing an empowered commission, possibly under the chairmanship of the Prime Minister, which could provide the overall guidance. The present scenario in India provides a grim picture of the "energy-debt" crisis and, if left unattended to itself, the widening gap between demand for energy and dwindling supplies will have deleterious consequences for the economy as a whole. The present state of affairs can eventually lead us to a very piquant situation of power riots. Unless we move to a market-oriented mechanism to overcome the besetting problems of operational, commercial, and financial discipline, the situation will keep on deteriorating and we will have bleak prospects of a turnaround in any future.

Conclusion

Keeping in view the present economic restructuring process, with particular emphasis on liberalization in the power sector, it is imperative that immediately appropriate decisions are taken for expediting commercialization and corporatization of various entities in the sector, without compromising on the need for fulfillment of social obligations while, at the same time, introducing a culture of competition for infusing efficiency and improving the quality of service through an efficient power pool operation. This will lead to regional coordination approach and will ultimately lead to the formation of a national power grid, for bridging the presently unbridgeable demand-supply gap.

Energy financing: an institutional challenge

by
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1. Introduction

Producing energy services is an expensive business. Whether it is the development of primary energy resources or their transformation into useful services, the process will require large amounts of capital. On average, countries invest between 2 and 4 percent of their national output or about 20 percent of total investment on energy-related capital expenditures. A typical household will spend 10 percent of personal income on purchasing the services produced. Very poor households can spend close to 30 percent.

The efficient use of this capital is an important factor in successful and sustained economic growth. As societies grow richer, commercial sources of energy are substituted for human labor. As societies grow more complicated with increased trade and transport, the demands on energy grow even more. In most rapidly developing countries, energy demands grow between one and two times the rate of growth of income. As incomes grow and efficiency improves, commercial energy services reach a new and expanding range of users and purposes. The challenge faced by all developing countries is the mobilizing of the necessary resources to ensure the continued and growing production of this basic need while at the same time, maintaining high levels of efficiency.

The size of the requirements has placed in question the availability of the financial resources. The numbers are large. In this region alone, it is estimated that between US$30 and $40 billion per year will be needed over the next ten years. Where will the money come from?

It will come from the same place it has always come from—the savings of society. In this region, savings' rates are high, usually over 20 percent of national income is saved. The future demands of the energy sector will place no more demands on these savings than they have in the past. Foreign savings can help, but only marginally. Typically, foreign savings have accounted for less than 15 percent of energy investments, and they eventually do have to be repaid. The issue is not the adequacy of resources, but rather their mobilization and efficient use.

Why is the mobilization of these resources regarded as such a challenge? The answer to this lies in the institutional structure in most of the energy sector. History, economies of scale, technology, government, and a great variety of social, political, and economic factors explain the shape and form of today's institutional structure. It is a sector dominated by large enterprises, both public and private, usually with considerable monopoly powers. Governments have traditionally played a critical role in both controlling and managing the sector as well as in mobilizing the resources required. The cost, scale, and long life of most investments have required an understanding or social contract between investors, consumers, and the energy enterprises.

Neither society nor technology remains in place. The world is undergoing a dramatic period of change with the increased globalization of production. Communications, transport, and technology are changing the way economic systems operate. Many societies have had to redefine the role of government. Financial markets have changed in an equally dramatic fashion. These changes have combined to call into question the existing social contracts as they apply to the energy sector.

Although the pressures for change are being experienced by almost all countries, the need and the ability to respond is different across countries. For some countries, particularly in this region, the need for change is being driven by the need to access capital markets. In others, particularly in Africa or India, the need to improve service delivery is paramount. This paper is about the need to revise the existing structures in order to meet the challenges of a changing world. Market structures need to be reexamined, the relevance of today's institutions questioned, the role of government reconsidered, and new understanding reached between investors and savers. This paper sets out some of the elements of this common framework in the hopes that all will gain from sharing this experience.

The general direction of change discussed in this paper is the need to move towards greater reliance on markets and market-based institutions and less reliance on the commanding heights of the public sector. But this will take time. For most of this decade, the public sector will continue to be the major source of finance for the power sector. A more realistic goal is one in which the process of institutional changes starts today so that by the turn of the century it will be possible for the private sector to assume most of the responsibility for financing electric power.

2. Market structure

With a few notable exceptions, in most of the world, electric power is produced, transported, and distributed in markets dominated by a vertically integrated monopoly. For the most part, these monopolies are owned by the state and run as public enterprises. In the U.S., the combination of the size of the market and its early development relative to the rest of the world has led to an industrial structure of regional monopolies, most of which are privately owned.

Until recently, few would have questioned the "rightness" of this structure. The electric power industry always has been considered a natural monopoly. Economies of scale and the integrated nature of the system meant that only one service provider made the most economic sense. These assumptions are increasingly being challenged. In the U.S., the rise of independent non-utility or non-integrated generators has resulted in competitive alternatives to some of the services offered by the regional monopolies. In the U.K., the services provided by a state monopoly were unbundled and competition introduced in almost all parts of the system. In Sweden, third-party access (TPA) has been established and independent generators compete within a framework of a common carrier transmission system. In New Zealand, the utility was split into different services and their legal monopoly eliminated. In Chile, private firms compete. In Argentina, the state monopolies have been broken up and private firms compete for franchises. In one country after another, plans are being drawn up to radically alter the existing structure of the industry.

What has brought about these developments? Why has this industry whose market structure has been remarkably stable for so long a period suddenly being confronted by these pressures for change? Three factors account for what is happening.

2.1 *Technology*

Up until about the mid-seventies, the economies of the industry were dominated by economies of scale. In the construction of power plants, changes in technology produced lower and lower costs with larger and larger plants. The growing efficiency of the large central power station combined with the need to coordinate transmission, communications, and distribution meant lower overall costs were achieved by an integrated monopoly. That the efficiency gains associated with size appear to have leveled off.

In recent years, technology has moved in a different direction. In power generation in particular, economies of scale have become less and less relevant. New turbine technology and the increasing use of natural gas have resulted in new generating units that show few economies of scale. The costs per kilowatt of capacity show little difference between large and small stations. In addition, these technologies are less capital intensive. A combined cycle gas plant, for example, costs less than half that of a traditional coal plant and can be built in about a third of the time.

Communication and control technologies have changed dramatically. The growing sophistication and cost declines of telecommunication and computer systems has meant that the information requirements of system management can be met in ways that do not require a vertically integrated firm. In fact, there may well be substantial diseconomies or communication and information failures associated with integrated operations.

2.2 *Size*

In both the developing and developed countries, electric power has been an industry of rapid growth. Systems doubling in size every decade has been the norm. Although these growth rates appear to have peaked in the industrial countries, demand continues to grow rapidly in most developing countries. A few decades ago, adding 100 MW to a system was a major investment and usually a significant part of the total. Today, countries such as China are adding 1,000 MW a month. Over this decade, Korea intends to double its capacity from 20,000 to 40,000 MW. Systems have grown to the point where economies of scale have become less and less relevant. Size, by itself, also appears to have introduced increasing costs in terms of efficiency and management.

2.3 *Performance*

Efficiency is always a problem with monopolies. The electric power industry is no exception. Without the discipline of the market place, efficiency is difficult to maintain and political imperatives substitute for normal commercial practices. This has been particularly true in most developing countries.

Even in the developed world, the utilities have not been models of efficiency; neither have they been models of inefficiency. Service demands have been met. Perhaps not at minimum cost, but nevertheless at costs tolerated by the society.[1] In contrast, in many developing countries, there has been a failure to maintain service levels, and problems and inefficiencies appear to have grown along with the monopoly. Frequently, the poor financial performance of these utilities has meant inadequate resources to maintain assets and meet the needs of growing markets. The result has been a growing dissatis-faction with performance; governments, consumers, and the enterprises themselves are expressing their discontent in greater volumes.

2.4 *Using the market: the role of competition*

If a monopoly structure for the market is not always producing satisfactory results in terms of performance and finance, what are the alternatives? Can they be realistically applied to developing countries? Are they different for large or small systems? What are the institutional requirements for managing a more competitive structure? Most of what is discussed below applies to networked services. The other common public monopoly in the energy sector in a number of developing countries is petroleum production and/or distribution. Since this is a traded commodity in which there is international competition, the justification for this market structure must lie in non-economic objectives. These monopolies are not usually efficient.

The availability of alternatives to monopoly provision of these networked energy services is not a theoretical concept. Almost all forms of alternative competitive provision of services exist in practice. They range from almost completely competitive structures for an unbundled structure of services to hesitant first steps, for a

[1] The greater reliance on private capital markets has been the main factor in maintaining an acceptable level of efficiency.

limited range of services. New combinations are being developed every day. They do work; the question is how well and under what circumstances.

The options of alternative market structures presently available fall into roughly six categories. These are broad classifications--various permutations and combinations are possible. In addition, the way in which the different market structures are managed in practice can make a difference to what happens in reality. They range from the vertically integrated monopoly to largely competitive systems.

1. The integrated public monopoly.
2. Regulated private monopoly.
3. Monopoly (private or public) with some competitive procurement of generation.
4. Unbundling the services; competitive provision of generation.
5. Unbundling the services; transmission and TPA.
6. Unbundling of all services except network management.

THE INTEGRATED PUBLIC MONOPOLY: This is the most common market structure for the power sector (and in a few cases, natural gas) in almost all developing countries. In larger countries (Brazil and India), it may take the form of several regional monopolies together with some administrative divisions, particularly at the wholesale level, of generation, transmission, and distribution. Public ownership and more importantly, public responsibility for raising the necessary capital, are the key features of this structure. One of the most important advantages of this structure is the ability of the political system to use it to meet non-commercial objectives.

Whether the utility is operated as a public enterprise or public corporation, entry into any part of the sector is restricted and pricing and investment decisions ultimately are made by government. Usually multilateral, external lenders have attempted to provide some discipline by use of targeted variables such as the rate of return on assets or the requirement that prices, on average, cover the long-run marginal costs (LRMC). Sometimes there are regulatory boards or price commissions established to assist in the process of developing tariff structures. In general, the signals of the market place are weak and conflict resolution is managed through the political process.

A common feature of this type of market structure in developing countries is the existence of a substantial part of total generation capacity, within the country, in the hands of the private sector or industrial enterprises (Nigeria, Indonesia, and India). Most of this capacity is not available to the network. This capacity has grown over time in response to the failures of the public networks to meet both the demands for quality and capacity.

The efficiency of these public monopolies varies considerably. Some are reasonably efficient in meeting a country's needs for quantity and quality of services. Others have failed to meet these goals. In most cases, politics dominates the investment decisions and there are many examples of costly investment decisions even in well-managed systems. A general observation is, that the more efficient is the overall governance of the country the less costly is this market structure.

REGULATED MONOPOLIES WITH PRIVATE OWNERSHIP OR PRIVATE CAPITAL: The present systems in many of the developed countries fits in this category. Whether ownership is public or private, the key feature is the use of private capital markets to raise the necessary capital. In order to satisfy the requirements of the capital market, a rate of return on capital is targeted with the market acting favorable or unfavorably to whether or not this target is achieved. It is essentially the substitution of a market determined target for the LRMC type of target used by external lenders in the case of national public monopolies. Where private ownership is permitted (U.S.), greater accountability exists for investment decisions. Where private ownership does not exist, politically motivated, and usually expensive, investment decisions (e.g., nuclear power in Ontario, Canada, and the U.K.; lignite plants in Victoria, Australia) are possible and ultimately require the government to bail out the utility.

In order to attract private capital, a clear set of rules and a means of enforcing the rules on both the government and the enterprise, is required. The relationship between the government and the enterprise has to be predictable and subject to an open and well understood judicial process. An independent judiciary is an essential requirement particularly where private ownership is involved.

Although the use of market-determined targets provides an important element of discipline into the overall operation of the system, the determination of the actual pricing structure is subject to a substantial element of political control. As

long as overall targets are met, the existence of monopoly leaves open the possibility of various forms of either price discrimination or cross-subsidies among consumer groups. In some cases, there is an attempt to base tariff structures on cost categories, but because there is little market feedback on actual costs, this tends to become a somewhat arbitrary process and subject to a good deal of manipulation for political and other purposes. In the U.S., complex legal and accounting structures have been developed to support the tariff-making process, but it has not prevented the use of regulatory bodies to achieve other social objectives. In recent years, the regulatory system has been used to reinforce environmental goals, using the ability to discriminate among consumer classes to subsidize these objectives.

The overall economic efficiency of the system can vary considerably depending on the degree of inefficiency introduced into the pricing system. The capital market provides some feedback on the efficiency of investment decisions although in most cases, this is muted by both explicit and implicit government guarantees on the debt. For the most part, the signals from the capital market are a commentary on the ability of the regulatory system to balance the competing demands of the political system.

MONOPOLY WITH SOME COMPETITIVE PROCUREMENT OF GENERATION: Introducing competition into what has been a vertically integrated electric power monopoly is a step a number of countries have taken. Countries (India, China, Malaysia, Philippines) are struggling to write the rules governing this competition in the face of both solicited and unsolicited proposals. It has turned out to be a complex process and one with many moral hazard risks. As yet, no developing country has devised a satisfactory set of rules.

One of the main reasons for this is because the competition has been so limited that what is left is another form of public procurement, albeit more efficient. The private sector or private firm has become a contractor to the existing monopoly for a set of specialized services which now includes finance. In some cases, there may be competition among private firms for provision of these services, but more often than not, it is a "negotiated" deal. The public utility or the government is deciding what plants are to be built, what technologies are to be used, where the plant is to be located, what product is to be produced, and at what price. The Hub River project in Pakistan or the proposed private sector plants in Jamaica, Philippines, and many other countries are of this type. Since the public sector is making most of the decisions, it winds up having to cover most of the risks. The private party is simply selling management, technical, and increasingly, financial services to the government or its agents. Competition is, at best, limited and constrained—as are the financial resources.

In these circumstances, the main regulatory concern is over the nature of the contracting process between the private producers and the utility that is now a monopsonist in the market for capacity and energy. In order to protect his investment, the private investor will focus on obtaining a satisfactory power purchase contract from the utility and look to government to underwrite the risks with respect to its own behavior or that of its agent (the utility).

In the U.S., with a predictable regulatory framework and a strong judicial system for contract enforcement, it has been possible for independent producers to work out satisfactory power purchase contracts. In the U.S., a greater degree of competition is being introduced which has greatly simplified the rule-making process. In Virginia, for example, the regional monopoly (VEPCO) has requested bids for construction of power plants mainly on the basis of the price it is prepared to pay for power. It has indicated the amount of and type of power it needs and approximately when and where, stated the price it is prepared to pay, and then asked for bids. The developer is then taking the risk on what plants to build and where. Given the final price (and certain technical qualifications), the profitability of the enterprise will be dependent on the decisions of the developer. The public sector need not be involved.

Fixing a price or a set of rules on how prices will be established would avoid the difficulties being experienced by countries as diverse as India, Indonesia, and Honduras as they try to contract for new plants. In the case of VEPCO and other utilities that have developed this process for future capacity additions, bidders have come forward with proposals to more than meet the capacity requirements.

The limitation on this approach in developing countries, in addition to country risks, is the lack of credible rules or operating experience with pricing regimes. Private suppliers will be unwilling to enter into contracts on this basis with the dominant public monopoly unless significant government financial guarantees are forthcoming. Perhaps, over time, investor

confidence can be increased to the point where contracts based on the price of power alone will be sufficient to induce investments in new capacity. In terms of the requirements for regulation, a predictable pricing regime is essential. Chile is the only example of a country in which investors have been willing to undertake capacity expansions on the basis of predictable expectations about prices and market structure.

In the Philippines, for example, the procurement of private generation capacity has been possible only with the government taking all risks with respect to prices and quantities. The independent producer receives a physical quantity of fuel from the dominant utility and then converts it to kilowatt hours for a processing fee. The independent producer takes no risks with respect to either input or output prices.

Expanding generation capacity through public procurement may introduce some efficiency in plant construction and operation, but may prove to be impossible to develop on the required scale given the limitations of the institutional and regulatory systems. At some point, given that they take all of the risks, governments will balk at undertaking these operations on too large a scale. The various BOT, BOO, and BOOT schemes have all required a long and complex process of negotiation and many, particularly the larger ones (e.g., Turkey), have failed to get off the ground.

UNBUNDLING THE SERVICES - GENERATION: The limitations for improvements in efficiency of simply moving to more competitive procurement of generation are obvious if they take place within the traditional monopoly structure. The vertically integrated monopoly is a formidable institution and even with the most sophisticated of rules and rule making processes (e.g., as in the U.S.), it's existence will make it difficult to introduce real competition, improve accountability, and avoid corruption.

Does generation have to be provided under conditions of monopoly? A few decades ago the answer to this question would have been, yes. Small systems dominated by one or two large central power plants and growing economies of scale would be the reasons given. As systems have grown and as changing technology has made economies of scale less relevant, it is now possible to consider the competitive provision of generation services.

Perhaps even more important has been the development of communication and information systems that permit the dispatching of electric power within a more market-oriented framework. In small systems, usually operating within a well-defined region, it was necessary to maintain close control over generation and its dispatch, insuring, on the basis of technical criteria, adequate reserve requirements and service quality. As systems have grown and started to interconnect, new protocols have had to be developed with respect to the trading of power among systems. In both North America and Europe, a number of power pools have developed to trade power and reserve requirement among large regional monopolies.[2] These power pools reflect various degrees of system integration, from exchanging power at the margin to more centralized control of the combined systems.

Since members of the pools had different sets of owners, different governments in the case of Europe, and different combinations of private and public owners in the case North America, rules have had to be developed to govern the interaction among the members. Initially, most of these arrangements were fairly simple and reflected only marginal transactions, but as greater integration has been achieved and in particular where club membership has no longer become exclusive—where independent generators become part of the system—rules have had to become more complex and inevitably this complexity has forced the rules to become simulations of what would happen in a competitive wholesale market.

In the U.K., it has developed into a wholesale spot market for generation services. In North America, some of the larger power pools are moving in the direction of similar market structures. In the U.K., generators bid at half hour intervals for a place on the load curve, for the provision of spinning reserves, and other technical services. The order and amount dispatched is determined by the prices offered rather than, for example, on a basis of the traditional engineering-determined merit order used in most systems. In other words, market prices have substituted for technical parameters. The profitability of each plant on the system is thus dependent on the ability of the plant owner to compete with respect to prices and costs. With the market determining prices, other market-based

[2] There is a nice discussion of various power pooling arrangements in Bardak Energy Services, report for the Australian Distribution Authorities, *A Discussion Paper on Power Pooling in Australia*, Melbourne, December 1992.

mechanisms have developed to arbitrage risk; a small but growing futures market for kilowatt hours is now developing in the U.K.

UNBUNDLING THE SERVICES - TRANSMISSION AND TPA: Transmission services, of all the unbundled services, appears to have the strongest element of natural monopoly. In most cases, it is either part of a vertically integrated monopoly or it is run as a separate and regulated public monopoly (India). In the U.K., the transmission system is owned by the private regional distribution companies and is subject to public regulation regarding who may sell and buy from the system. In the U.S., recent changes in legislation (November 1992) have started the process of opening up the transmission systems owned by the regional monopolies to permit TPA.[3] TPA has been permitted in Sweden and a few other countries, but has been rejected by several of the major countries of the European Community interested in protecting their state utilities from competition.

TPA permits generators to directly reach consumers without going through the intermediation of the regional utility. The large 2,000 MW Tysdale plant built by ENRON in the U.K. was financed on the basis of power purchase contracts negotiated between the company and power consumers. This would not have been possible unless producers and consumers were confident that adequate transportation arrangements existed.

Permitting some degree of competition for the larger customers, which in most developing countries could account for over 75 percent of the load, by permitting TPA to high-voltage transmission lines could be an attractive way for pressuring greater efficiency from the system. It will create pressures to price energy to reflect costs. If customers are given a choice, they will shop around for prices and qualities of service that best meet their needs. At present, customers have few choices—usually a poor quality of service at subsidized prices from the public monopoly. There are many examples (Indonesia, Nigeria) of customers paying a multiple of the public price through auto generation in order to obtain a better quality of service.

Transmission services can be further unbundled by separating out the system management. In an integrated monopoly, the system management—what plants are on line, when, which are in reserve status, which provide spinning reserves, over which links is the power transmitted, maintenance of voltage and frequency, etc.,—are all centralized functions. Whether TPA is permitted or the transmission lines are privately owned, there will still be the need for the centralized management of the system. This need for centralized management of the system is usually advanced as an argument against TPA and for the maintenance of an integrated monopoly.

Recent experience, however, suggests that it is possible to separate out the system management functions and earlier fears that this would result in deterioration of the system's functioning have proven to be unfounded. In the case of the U.S. power pools, many of the system management functions have been delegated to jointly owned and managed control centers. In Europe, many of the national utilities have conceded considerable authority to centralized management centers. In the U.K., the National Grid Company is both the owner of the transmission network and the manager of the system. In Australia, consideration is being given to the establishment of a national grid or system management function that is separate from the ownership of the interconnected transmission system.

The system management functions are clearly a natural monopoly and present a number of issues for public regulation in addition to those discussed above under ownership and access to the transmission system. System managers are in a position to determine the operations and profitability of all parts of the system. Unless the rules are clearly specified and understood by all parties, there is the possibility of considerable discord and political fallout, particularly where the legal structure for contract dispute is underdeveloped.

UNBUNDLING SERVICES - DISTRIBUTION: Distribution systems remain one of the more difficult areas for changing the market structure.

[3] TPA to transmission lines (or in the case of oil and gas, pipelines) occurs when another seller of the service, other than the owner of the transmission line, has access to the physical facilities for the transport of power on their own account. Essentially, this requires the owner of the transmission facility to act as a common carrier. TPA generally is strongly opposed by the existing carrier because it gives competitors direct access to customers its previously monopolized territory. French and German opposition to the concept has stalled the introduction of TPA into the European Community.

In New Zealand, contestability was introduced at the generation stage and transmission structured as a national monopoly, but the basically municipal distribution systems were left untouched. The gains in efficiency—lower wholesale prices—were not passed on to the bulk of the consumers but were absorbed by the regional distribution monopolies and in profit taking by the government. Recent legislation is changing this and the regional monopolies no longer have exclusive rights to distribute in their territory. In the U.K., larger customers (presently 1 MW and above) are free to negotiate directly with suppliers, with the regional distribution company required to move or "wheel" the power over its lines at established prices. Australia and a few other countries are considering similar arrangements for permitting competition at least among the larger customers. In those countries with reasonably functioning billing and payment systems, there is no reason to presuppose that competition cannot go down to the level of the residential household. In the U.K., the intention to do so has been publicly announced.

These type of changes in the market structure of the distribution systems, limits the degree of monopoly to what can be described as the wires service. Customers deal directly with the supplier, and the wire service or common carrier transports the energy at established rates. The advantage of this is that it limits the public regulatory burden to determining access and pricing to the distribution and transmission networks. Long-distance telephone services have reached this point in a number of major countries.

One alternative that has been considered in a number of countries is what is known as benchmark or yardstick competition, where there are a number of regional distribution monopolies, usually owned by municipalities and in some cases by private companies. Most of the distributors are likely to face the same set of wholesale prices; the range of profits and prices of the distributors should then reflect their relative efficiency. If the regulatory authorities have control over consumer prices, tariffs can be set to reflect best practices, and local government forced to absorb the inefficiencies. Widespread knowledge of the relative performances of the various distributors will apply public pressure on the poor performers.

The Province of Ontario, in Canada, has such a system. Electricity is wholesaled by Ontario Hydro which has a virtual monopoly on generation and transmission, but power is distributed by municipal electric associations (MEAs). Ontario Hydro "suggests" a set of retail rates to the associations which presumably reflect a sufficient margin to cover distribution costs. These rates are widely publicized and it is difficult for any association to put in place a different tariff structure. The profitability of the association, or the deficit to be paid by the municipality provides an incentive for efficiency.

This system of benchmark competition is not without its problems. What is a reasonable set of rates both at the wholesale and retail level is still a matter of considerable public intervention. In the case of Ontario, there are numerous disagreements between the utility and the municipalities over what is a reasonable structure of tariffs. Recently the MEAs, who have to deal with the final customer, have been complaining that the wholesale rates are excessive and that they are bearing the burden for inefficient investment decisions at the wholesale level.

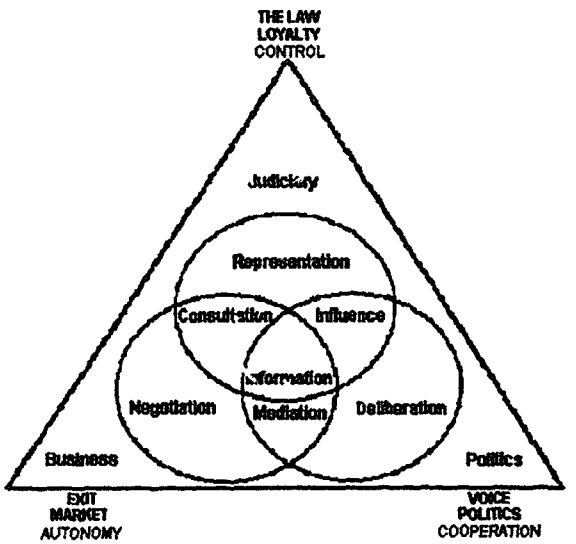
The effectiveness in developing countries in a system of benchmark competition will have to be determined by experience. Key parameters necessary to make it work are the openness of the information system and the willingness of government or the regulators to accept the consequences (the profits and losses of the distributors). Poor and unreliable information systems, a common feature in many developing countries, will make comparisons difficult and leave ample space for argument and excuses.

3. Institutions

Confusing institutional development with management is a common misperception. Improving management is only a narrow part of institutional development and is usually associated with specific enterprises. It is a much broader concept and covers those structures in society that govern the way in which individuals, business, and government interact with each other. Institutional development is about how these structures change in response to the changing needs of society. Property rights and how they are treated, for example, is one of the more fundamental institutions of society. It is this broader definition that is used in this paper.

There are many ways of classifying society's institutions. In examining the options for change

in the energy sector, and electric power in particular, the following figure presents a simple framework that provides useful insights.[4]



The use of triads of this type is common in academic and popular management literature. This one owes much to A.O. Hirschman, Exit, Voice and Loyalty (Cambridge, Mass.: Harvard Univ., Press, 1970). For further discussion and a more extensive list see R.W. Keidel, Game Plans: Sports Strategies for Business (New York: Dutton, 1985) and Keidel, "Team Sports Models as a Generic Organizational Framework," Human Relations 40 (1987): 591-612. This particular framework was originally developed in a paper Private Power: the Regulatory Implications, delivered to the Singapore National Committee/World Energy Council, ASEAN Energy Conference, Singapore, June 4-5, 1992.

Society's institutions are divided into three main categories according to their principle means of social interaction. There are the political institutions that rely primarily on voice or cooperation, the judicial institutions that emphasize the rules of the game or the legal structure, and finally, the market-based institutions the rely on negotiations or the exchange of property rights.

The stage of development of these institutional structures will set the limits on the options available for reforming the energy sector. If, for example, a country has an underdeveloped definition of property rights or lacks the means or will to enforce those rights, market-based institutional structures are unlikely to function well. Business relies on the negotiation and exchange of property rights. The inability to enforce contractual arrangements can be a serious impediment to the development of some market structures such as the example cited earlier of a power company contracting out generation solely on the basis of price.

In many developing countries, the lack of openness of the political system is a serious impediment to promoting effective regulatory structures. This shows up in the difficult and contentious issues surrounding the resettlement of populations affected by hydro projects. The affected populations are often excluded from the decision-making process and this, combined with weak administrative and legal structures, leads to confrontation rather than negotiation.

These fundamental institutional structures of society are slow to change. Revolution occurs when existing structures reach a breaking point, but even in these extreme cases, the change is likely to be confined to the political sphere with other institutions adapting at a much slower pace. The difficulties now being encountered in the former Soviet Union are a good example of the strength of existing institutions and their resistance to change.

Any change or process of reform will have to take into account the existing institutional structures—the strengths and weaknesses of the political, judicial, and market institutions. Institutional structures are inherently conservative and will move only under pressure. Yet the ability to change will be limited by this same institutional structure. This is the basic tension of the reform process.

The tension between the need for change and the limitation of institutions produces a number of issues that will have to be addressed in any program of reform.

3.1 *The pace of reform*

Either too fast or too slow will present problems. Determining what is "just right" will depend on a country's institutional endowments and the political capacity to manage change.

The developed world has produced contrasting models of the reform process. In the U.S., change has been of the more stately variety, probably because the need for change was of a lower order of magnitude in terms of potential gains and political costs of resistance from a well established institutional structure. In the U.K., in contrast, there were considerable pressures for change because the existing public monopoly was beginning to develop higher levels of

[4] This framework was originally developed in a paper, *Private Power: The Regulatory Implications*, delivered to the Singapore National Committee/World Energy Council, ASEAN Energy Conference, Singapore, June 4-5, 1992.

inefficiency and potentially greater financial demands on the public purse. Both the need and the capacity for change were greater and the resulting reforms were of a more radical and urgent nature. Somewhere in between are Australia and New Zealand: the initial steps of commercialization and corporatization have taken place but the process of further change has been stalled as opposing forces have had time to marshal their resources.

What lessons for the developing countries can be drawn from this experience? In many cases, the need for change is more obvious, yet at the same time, the institutional capacity to manage change is weakest. The temptation in most countries is to go for a gradual or controlled process of reform. Commercialization is followed by corporatization, some competition for procurement and operation of power plants is permitted, and perhaps the sale of some part of ownership to the general public. In all cases the dominant monopoly has remained firmly in control.

This may make sense in countries such as Thailand and Malaysia where reasonably efficient national monopolies exist and prices generally covered costs. The pressures for change are driven by the need to access new sources of capital and the desire on the part of governments and utilities to develop more efficient, and less political, forms of governance.

In other countries, such as Argentina, poor and deteriorating quality of service and a tradition of public mismanagement, required a more radical restructuring. Attempts at managing public enterprises through a more efficient regulatory structure (commercialization and corporatization) had failed and a new paradigm was required. The dominant monopolies were split up and sold to private interests with significant foreign participation. (This also has been the pattern for many telecommunication reforms where the sector has been characterized by poor and deteriorating quality of service.)

One simple lesson emerges from the experience of both developing and developed countries: the more extreme the problem, the more radical the required solution. Speed is also important. A stately pace of reform produces a stately pace of results. In most countries with severe problems (e.g., Bangladesh and Eastern Europe), the political system is unlikely to be able to manage a slow pace of reform or to accept the slow payoff in terms of improved efficiency and service levels that will follow. (In fact, one can argue that the "gradual" reforms of the past two decades urged on these countries by the World Bank and other international lenders, has produced little in the way of improvements in efficiency.)

3.2 *Disequilibrium*

Institutions, like people, do not change unless there is sufficient discomfort with the present situation. In trying to manage the process of reform, there is the temptation to try to minimize change to the point where it just relieves the present discomfort. In the power sector, the inability to attract financial resources is forcing many countries to consider alternatives to present institutional structures. The temptation is to try to find a path of reform that requires the minimal amount of change in existing institutions.

Reforming institutional structures is essentially a messy process. Once the first, tentative steps have been taken, they will produce their own dynamism and set in motion a process which will stagger from one disequilibrium to the next. Often the outcomes are unpredictable and there is a general tendency to underestimate the speed at which change will be induced. What happened in the U.K. is a good example of the process.

Most countries are trying to find a path of compromise between the present prohibitions on entry and the alternative of a completely unrestricted market. There is an understandable reluctance to give up all controls over what has been a tightly controlled industry. No country is willing to risk uncertain or unpredictable outcomes in such a politically and economically sensitive industry.

Finding an institutional path between protection of monopoly privileges and introducing competition has proved to be extraordinarily difficult. Once any degree of competition is introduced, the system will be pushed in the direction of either falling back on former restrictive practices or in the direction of further competition. In the U.S., for example, once independent power producers (IPPs) were permitted entry, pressures for TPA were quick to grow and the system is being pushed in the direction of a complete unbundling of services in a competitive market framework. A similar situation has arisen in the case of telephone services; once the long distance monopoly was effectively challenged, competitive forces were released across the spectrum of services. In the U.K., the structure of the electric power industry has changed

at a more rapid pace than anyone had predicted. Regulation has been scrambling to keep up with the pace of change.

3.3 *Capacity constraints*

What about the constraints of institutional capacity? It has been argued that those countries in the worst shape are also those with the weakest capacity for institutional reform. This has been interpreted to mean that in these countries the pace of reform must be set by the limitations of this institutional capacity and therefore reforms must be of the slow and deliberate kind. The capacity to develop and implement a regulatory framework is sufficiently limited to require a long period of time to gain both experience and to develop the necessary skills.

The question on institutional capacity needs to be divided into two parts: 1) the capacity to manage change, and 2) the capacity to accept change once it has taken place. The processes presently underway in Australia or Thailand all require the existence of a significant institutional and political capacity to manage a process of change. And even in these cases, it is not clear whether or not this capacity will, in fact, be used to thwart change. In Argentina, in contrast, the changes were radical enough to require a completely different form of institutional capacity. In this case, the management and financial skills of both the domestic and foreign private sector were utilized to overcome the limited capacity of the public sector.

In Bangladesh or India, the capacity of the public sector to manage change is undoubtedly limited, but the needs are great and alternative skills exist in the private sector that could respond to the immediate imposition of a more competitive framework. Importing some of these required skills by involving foreign producers and financiers is also an option that may be required by a weak capacity to manage change. In other words, putting in place a more radical structure to begin with may be easier and may be the only alternative for countries that lack the capacity to manage a process of change.

Historically, regulations have tended to develop in response to demands created by new situations rather than the other way around, where regulations are changed to induce new situations. Forcing the pace of change through more radical institutional restructuring of the sector will also force the pace of regulatory reform. In Argentina, for example, significant change has taken place, but the regulatory structure required to manage the new institutional structure is still in its early stages of development.[5] In the U.S., the recent changes in legislation and attendant regulations, are the result of the technology induced competitive environment. In the U.K., regulatory practices are evolving as more and more experience is gained with operating a competitive system. In India, the intention to allow investments in private power is forcing the public sector to consider developing the appropriate regulatory framework. Regulators are inherently conservative and are more likely to react to change rather than be the inducers of change. There are no examples of a detailed and comprehensive regulatory framework being put in place prior to the reform or structural changes in the sector.

3.4 *Ownership*

State ownership of many of the energy enterprises is a common feature in most countries, developed and developing. Although it is easy to see how this came about because of scale economies, the weakness of capital markets, etc., it would be unrealistic to ignore the political or control aspects of state ownership. Direct, political control means considerations of equity, redistribution of income, employment, national security, regional development, and other social goals become an important part of the public interest in this sector.

The exercise of this political control is reflective of the societies themselves. Where stable governments exist, policies and practices in the power sector are more predictable; where governments change frequently, so does governance of the sector. In the more open, pluralistic societies, the sector is caught up in the numerous and often conflicting goals of the society. In the more closed societies, the sector often serves the interests of the elite.

In the developed countries, the political control of the sector is tempered by the more open nature of the society and in particular by the checks and balances provided by existing social and economic systems. Probably most important of these checks and balances is the need to access private capital markets. Rather than direct investments in the sector, these

[5] See M. Alexander & C. Corti, *Argentina's Privatization Program*, Cofinancing and Financial Advisory Services Discussion Paper, World Bank, Washington, D.C., August 1993.

governments (e.g., France, U.K., Canada, U.S.) prefer to tap the private capital markets usually with some form of government guarantee. In seeking private capital, these governments have to confront the contradictions between social and commercial objectives. Enterprises that ran large deficits are unlikely to attract private financing, even with a government guarantee. Thus, some balance is achieved between social and commercial objectives. In contrast, in developing countries, the existence of what can be described as a soft budget constraint, allows noncommercial objectives to dominate.

In addition to the discipline provided by capital markets, the more open nature of these societies permits the existence a numerous interest groups to organize and to voice their demands on the political system. In general, a better educated groups of consumers, industrial users, regional interests, environmentalists, etc., are all able to voice their demands and the public sector is required to set up mechanisms that permit the resolution of the inevitable conflicts. Public regulatory commissions and other mechanisms permitting a more open public debate help to moderate conflicts and discourage the more extreme demands of special interest groups on the political system.

These political demands, however, cannot be ignored—but neither can their costs. How to balance these conflicting objectives is the cornerstone of the regulatory process.

4. Regulation

Why regulate at all? This is not a trivial question and needs to be answered before moving on to asking how and what to regulate. Governments regulate in almost all matters of business or commercial activity, even if it is only providing the framework for property rights and enforcement of contracts.[6] This is the setting of the "rules of the game" that is considered the normal function of government. Going beyond these rules of the game to a special set of rules and regulations that apply uniquely to one activity is usually what is meant by regulation. The need for these "extra" rules is assumed to be the result of market failure, the existence of natural monopolies, and significant public good qualities of the sector. Any one of these is assumed to be a sufficient reason for introducing some form of countervailing power through public regulation.

Control over excess profits of monopolies has always been the traditional reason for introducing public regulation. In fact, in most of the developing world, contrary to the expectations of theory, these monopolies generally produce substantial losses. In exercising control over these monopolies, governments obviously have had other objectives in mind.

Whether rightly or wrongly, this industry along with a few others, is assumed to be of strategic interest to the state. The importance of the industry in economic growth, the strategic nature of energy choices in defining the national well being, and the potential redistribution of income that can be achieved through determining access to services, are among the many and varied reasons given for exercising a greater than normal degree of state control over this activity. Sometimes these are referred to as the public good aspect of electric power production and consumption. In many cases, these aspects have been considered of sufficient importance to warrant direct control or ownership by the state. Even in many developed countries these "public" goods have justified a substantial level of state intervention. In France and the U.K., for example, the investments in nuclear power were viewed in terms of strategic or defense related decisions.

The public good considerations associated with this industry have invited the broader participation of political controls in its management. Once this happens, the industry becomes subject to a negotiated process of control in which varying interests and groups compete for leverage. Commercial concerns for profitability and financial viability are only one of the competing elements in this process of control.

This process of political negotiations results in a social compact or understanding where industry is managed in each society. In many developing countries, this social compact is one which results in the state treasury bearing the ultimate

[6] The term *regulation* as it is used here generally refers to economic regulation. Most countries have a variety of licensing and other requirements with respect to physical sighting of facilities, health and safety requirements, etc. Although they may, in some cases, be specific to the sector, they are usually part of an overall package of rules governing most industrial and commercial activities.

costs. Labor receives higher wages or greater employment in return for its support of the system. Industrialists receive subsidized power, regions get their dam, other groups, either the poor or the politically deserving, get privileged access.

The consequences of this process are likely to emerge only slowly over time. In many countries, the constraints of the state treasury, and a management beset by conflicting objectives, ultimately leads to a deterioration in access and service levels, along with increases in costs and inefficiencies. Consumers complain about poor services, business develops alternatives and opts out of the system, and everybody petitions for larger subsidies. Under these pressures, the industry has become a political liability and the political and strategic nature of the industry is being subject to greater scrutiny.

In an increasing number of countries, the strategic or public good aspects of this industry are being questioned. In New Zealand, it has been assumed to be just another commercial activity and subject only to the regular rules governing commercial activity. In Chile, the government has withdrawn from most of the specialized regulation of the sector and settled for simple pricing rules to control monopoly profits. In the U.S., the concept of obligation to serve in exchange for monopoly rights is being eroded by competition from IPPs. In other words, the existing and increasingly unstable social compacts are in the process of being rewritten. The role of the industry in the society is being redefined and the boundaries between public and private interests re-drawn.

It is within this framework that the question of whether to regulate and to what extent must be answered. In the more developed world, there appears to be a greater confidence in the use of market mechanisms in directing the public interest and an increasing willingness to treat this industry within the normal commercial framework of rules and regulations.[7] The developing world, perhaps justifiably, does not have this same sense of confidence in its more underdeveloped commercial environment. Governments still seek to exercise the public interest, but are looking for alternative means of control—a new social compact that will be less destructive of efficiency and financial viability than those presently in force. No special regulation but informal understandings between government and the utility, New Zealand style, may not been an option.

Thus, the determination of the appropriate regulatory framework is more than simply a matter of optimizing economic performance but must take into account other objectives of the society. Inevitably, this requires a process in which conflicts of interest are resolved in a way that is not excessively costly to the basic economic concerns of profitability and efficiency.

Using the institutional model developed earlier, regulatory institutions in most developing countries are somewhere in the bottom right corner of the triangle: it is essentially a political process. The incipient regulatory bodies are simply another department of government. They are run by civil servants or technicians and are responsible to a minister of government. The major advantage of this type of structure is that it simplifies political control. The major disadvantage is the predominance of the short-run political imperatives that can result in excessive long-term economic costs.

In the U.S., the institutional structure is somewhere in the top part of the triangle where a judicial process dominates. There are numerous quasi-judicial bodies where a commissioner or group of commissioners, usually politically appointed, sit in judgment over the interested parties. The independence of the commissioners can vary considerably as can the openness of the discussion. Their effectiveness depends on the existence of well-established judicial procedures and a tradition of public participation. Their costs, however, are not insignificant.

In recent years, there has been a greater interest in developing institutional structures that would place greater reliance on market signals, that is more in the direction of the bottom left side of the triangle. Recent changes in the regulatory process in the U.K. are of this type.

The answer probably lies somewhere in the middle. There is a need to find an institutional structure that utilizes existing strengths of the deliberative or cooperative traditions of many societies but which, at the same time, recognizes the weakness of the judicial process and places greater reliance on more impersonal market forces.

[7] In the developed world, however, regulation is not dead. Concerns for the environment are being substituted for distributional and other economic objectives by those seeking to redefine the existing social compact. Integrated resource planning and some forms of demand side management now being pursued by regulators is simply another form of social goods or objectives being imposed in the name of the general public interest.

Given the limitations of present administrative structures and political systems, there is probably no alternative but to increase the competitive forces in the industry being regulated and, ultimately, in the economy as a whole. It makes a difference if you start with the view that what you are regulating is inherently a monopoly and thus your job is to minimize the potential distortions, or that monopoly is to be discouraged and your job is to maximize competition.

In the past decade, there have been some important developments in both theory and practice supporting the view that competition is the most effective and efficient framework for under-pinning the regulatory process. The theory of contestable markets where the focus is on opening up markets and understanding the barriers to competition, has had a major impact on the intellectual foundations on how governments should regulate.[8] The regulatory reform process in New Zealand offers a dramatic example of the power of these ideas. The reform process has focused on entry and exit conditions or, in other words, contestability. The job of the regulator in addition to protecting the consumer, setting standards, etc., is perceived as one of ensuring fair entry into any aspect of a regulated business. Anyone willing to put their own resources into a business has a *de facto* right to do so, provided he bears the investment risk. The regulator is there to ensure that existing institutions do not use their market position to prevent entry.

The effect this has on the deliberative side of the process is dramatic. Deliberative bodies have used their powers over monopoly providers of services to redistribute with considerable impunity, income and privilege. Insisting, for example, that household consumers be subsidized at the expense of industrial consumers no longer is possible. Suppliers will come forward to provide power to industry at prices that do not include the consumer subsidy. A telephone company that provides an inefficient service will find new competitors entering the market.

4.1 Regulatory institutions

The inference drawn from the discussion above illustrates that in developing countries, maximum use should be made of market, rather than administratively devised signals. This will minimize the demands placed on scarce management skills and limit the calls on a usually weak and overburdened structure of public administration. It also makes a difference if regulation is seen as the means of limiting monopoly or as the means of promoting competition. In the examples of New Zealand and the U.K., the primary economic function of regulation is seen as promoting competition; in contrast in the U.S., regulation is seen as the means of limiting monopoly power. Depending on which of these underlying premises is used, the demands for regulation can be quite different.

Given that the need for regulation has been minimized, there is still the question of the most appropriate structure for the regulatory framework. Who should regulate? Is it a technical group or a political group? Who should appoint the regulators, from where, and for how long? What are the checks on abuse of regulatory power? How independent (and from whom)? Who participates in the decision-making process? What is the legal status of the regulatory authority; can it make decisions or is it just an advisory group? Should there be more than one, and at what level of government? Should there be special authorities for each sector?

The answers to these questions will depend on the process of reform underway and, equally importantly, on the institutional and political structure of the country. "Borrowing" models from other countries could prove ineffectual because the underlying institutional structure that makes it work in one country and is not present in another. In terms of the model above, it is dependent on the strength and capacity of market-based institutions, the independence and effectiveness of the judiciary, and the openness of the political system. The section below takes up some of the issues that have to be addressed before modifying the regulatory framework. The answers are necessarily tentative and have to be considered in light of individual country circumstances.

Regulation is generally considered to be a public good and therefore the function of government. The issue is how should the government exercise this function. In developing countries, there has been a tendency to appoint administrative boards that act in an advisory capacity to the minister. With few exceptions, these boards have focused narrowly on tariff and pricing issues; investment decisions and environmental issues are handled elsewhere. Even

[8] W. J. Baumol et al., *Contestable Markets and the Theory of Industry Structure* (New York: Harcourt Brace, Jovanovich, 1988) revised edition.

within their narrow mandate they have not been notably successful. As long as the real decisions are made at a ministerial level, the temptation will be to bypass the regulator. The make-up of these boards reflects their status and they often become patronage jobs. Few have the technical capacity other than to accept the information provided by the dominant monopoly.

Attempts to increase the independence of the regulators through legislation or through the "independence" of the appointees has not worked, because the required underlying institutional structure is not in place. In the U.S., for example, where such regulatory bodies are common, there is a strong judiciary system for arbitrating disputes, a technical capacity for managing information, and a greater willingness on the part of the political system to delegate control. The openness of the system encourages debate and compromise. In most developing countries, there is no tradition of open public hearings in which interested parties are asked to come forward with their views and positions.

Until the necessary institutional structure is in place, the regulatory systems of most developing countries will have to rely on a combination of more effective political or voice systems and use of market information. The issue is not that regulatory bodies lack independence, but rather they lack the political representation required to be effective.

The trouble with the present predominantly political approach is not the deliberative process itself but the narrowness of the participation. There is little public debate and there is no structured forum where interested parties can pass information to each other or engage in a process of negotiation and mediation. When the World Bank comes into town and requires a tariff increase as a condition for its loan, the general manager goes to the minister, who in turn sees his job on the line and an impasse is quickly reached. At best, there are unflattering editorials in the local newspaper about either the cold hearts of the bankers or the inefficiencies of the power company. Nowhere is there a structure that would allow the power company to explain or defend its needs for a rate increase or for consumers to understand the link between tariffs and the quality of the services received.

Opening up the process is essential. One way of doing this is to recognize the regulatory board as a political body rather than confining its mandate, as is presently done, to technical reviews. By explicitly making it a political body, a broader representation of interested parties can be invited. In other words, it is a move towards the center of the triangle where the deliberations are influenced by better representation. On the board, one could include the representatives from large and small producers and consumers—the CEO of the power company and the housewife, representatives from the financial community, environmental interests, the press, etc. This is in contrast to most present systems in which the interests of producers rather than the users of the services predominate. The objective is to provide a structure where difficult and often contentious issues can receive an open airing—where users as well as producers have a voice.[9]

The effectiveness of the process will depend, of course, on the information that is available. The civil service in providing the technical and secretarial functions for such a body, would play this important role. This type of a more cooperative decision-making process mirrors many of the more traditional ways in which decisions are made in many developing countries.

How much independence should be given to regulatory bodies? This is a difficult question to answer. It would be unrealistic to assume that such important bodies could be completely isolated from the normal political process. Who gets appointed, for how long, under what conditions, and with what authority and scope—are all political decisions. Ultimately, government and its political leaders must answer to the body politic for all aspects of governance, including regulation. Different societies will draw different lines of responsibility around their various institutions. Over time, many of these boundaries will be re-drawn.

[9] An interesting recent example of this type of regulatory structure occurred in the Province of British Columbia, in Canada. Service is provided by a publicly owned, dominant monopoly. The utility had been facing increasing opposition to its plans and policies from a wide range of community interests. The government and the formal regulators were unable to find a politically acceptable way out of the impasse. An informal advisory group was established by the utility and all interested parties were invited to participate. Independent consultants were hired to provide information to all parties and to facilitate the process. After a difficult and contentious beginning, the different groups came to the realization that no decisions would be taken by the government until their recommendations were received. This forced the groups to seek the necessary compromises.

The effectiveness of these institutions will be governed less by their "independence" than by the degree to which the process is open, accountabilities clear, and adequate information availability. It is possible, for example, for a regulatory board to be a purely advisory committee to the ministry and have little or no independence. But, its effectiveness will depend on how well it represents the interested parties, the openness of its decision-making process and the reliability and comprehensives of the information it receives. On the other hand, even with complete independence and binding decision making powers, it will be ineffective if it is an unrepresentative body with processes that are secret, and with limited access to information.

The status of the staff or technical support for regulatory bodies is another independence issue that needs to be considered. It may be more important to ensure that the staff is protected from political pressures, than the Board itself. The timely provision of adequate information will be a critical part of the process of negotiation and compromise behind any regulatory decisions. The process will be made easier to the extent that all parties can agree on the facts. There are numerous ways this can be done and each country will have to evolve its own system that best fits its own institutions and political processes.

A more open decision-making process is a necessary but far from sufficient condition for an effective regulatory framework. There must be a means of enforcement, of bringing a reality check to the discussions of political and economic interests. In terms of the diagram, it is not sufficient to remain only in the right half of the triangle. Even in the U.S. system, where the rules of the game with respect to discussion and representation are structured and reasonably open, the system has an ultimate reality check in the market. Public commissions and interest groups cannot make or change the rules without keeping a careful eye on the capital markets. At the end of the day, utilities are going to have to face a market test which provides an unambiguous set of signals. In recent years, for example, regulatory bodies have introduced the concept of "due prudence" in determining what investments can or cannot be included in the rate base. This has increased the risk to investors and raised the cost of capital. All parties, the investors, the utilities, and the consumers have had to modify their behavior in response to the signals of the market.

How does one avoid the capture by the industry of the regulatory process? The history of regulation in many countries is replete with examples of the capture of the regulators by those being regulated. The broader type of regulatory body found in the New Zealand helps avoid this problem. In New Zealand, the regulation of all utilities falls under the Commerce Commission which is responsible for normal commercial activities. In other words, utilities are treated just as any other industrial or commercial activity. Given its broad mandate, the Commission has no option but to focus on the entry and exit process, competitive conditions, monopoly practices, commercial codes, contracts, etc. In the U.K., there are separate regulatory offices for each of the utilities, but given the basically competitive framework that has been established, their role is focused on the maintaining the competitive framework and the prevention of the abuse of monopoly powers. In the U.S., there are examples at the state level (Ohio) of regulatory commissions with authority over multiple sectors.

This option of regulating multiple sectors may not be particularly effective in most developing countries. The single authority covering all utilities requires that a well-functioning commercial code and its supporting institutions be in place. Few developing countries, for example, have policies or legal structures that seriously address anti-competitive policies. This will be a slow and difficult process and is equivalent to a movement towards the upper part of the triangle in the model. The type of more politically representative body suggested above can avoid the problems of capture by ensuring that all parties are represented.

Of particular concern will be the role of the dominant supplier. In almost all cases, the development of competitive alternatives will take time, and the new suppliers in the market will be small relative to the existing monopoly. The national monopoly through its power purchase arrangements and in its day-to-day operations is usually in a position to determine the commercial success of any potential competitor. It is likely to have mixed views on the participation of independent producers in the generation of electric power. On the one hand, it will welcome the additions to capacity, but on the other hand, it may well see the project as a competitive threat and use its controlling position to either threaten the commercial success of the project or, alternatively, collude with

the private investors to share the gains from non-competitive practices.

It will be essential for the government to establish, through the regulatory process, a credible arm's-length relationship with this dominant supplier. Widening the base of the participation in the deliberative process will help, but inevitably, with its superior access to information and substantial resources, the present monopoly will be in a strong position.

Take, for example, the problem of what price is to be charged to alternative suppliers for use or access to existing transmission and distributions systems. If one knew what were the costs of providing these services, this would be a relatively simple problem. But unfortunately, because these enterprises are seldom operated on a commercial basis, this information does not exist and if it does exist, the costs are likely to be an arbitrary allocation of inaccurate historical costs. Thus, when asked to produce the required figures, the monopoly is in a position to set prices on the basis of cost estimates that can be easily manipulated to place them in a favorable position with respect to the competition. Most governments have no other alternative sources of information because they have relied exclusively on the data generated by their own utilities.

In practice, this means if regulation is to be effective in encouraging new entrants into the business, all participants must be treated equally. This will not happen unless steps are taken to place the existing monopoly on a commercial basis. Thus, removal of subsidies and harmful non-commercial objectives imposed by government, followed usually by corporatization of existing state enterprises, is a critical first step in regulatory reform. In the short-run, the most effective means of protecting against the dominance of a few special interests is to widen the base of participation in the deliberative process.

4.2 *What to regulate*

Trying to control everything is not likely to be efficient. The more detailed or more comprehensive the control mechanism, the more regulation substitutes for management. Finding the balance between rules and administrative discretion in setting the main parameters within which energy enterprises are to operate, is difficult to find in practice. Aside from safety standards, protecting consumers, and similar issues of public concern, the usual areas of regulatory action are prices, investments, entry and exit, and, increasingly, the environment.

PRICE: Few issues are as contentious and difficult to deal with as pricing of services provided by "natural" monopolies. In the case of services produced in a competitive environment, price regulation is not an issue; prices are derived from the negotiations of many buyers and sellers. In the case of electric power (as in other system dependent services), pricing can be quite complicated not only because of the different qualities of service possible, but also by the fact that costs are both time-of-day and system dependent.

Given the complexity of relating prices to costs, regulatory systems have tended to favor gross simplifications of the rules for pricing. In most cases, an "average" price for a variety of services and costs is used. Under rate-of-return systems of regulation (U.S.), prices have been set to insure that revenues are sufficient to cover costs, including capital costs. The distribution of these costs over the customer base or load curve is usually accomplished by a set of rather arbitrary accounting rules and legal precedence. It is only in recent years, for example, that regulatory systems have permitted "time-of-day" based pricing in spite of the fact that a major element of costs is related to the time of consumption. In the 1970s, the World Bank and other international lenders have introduced the concept of LRMC as a complement to rate of return rules. In this case, prices are set so that average prices cover projected system expansion costs.

In some ways, by focusing on one simple variable—the rate of return or LRMC—simplifies the regulatory requirements. In others, it complicates it. Since there are no market signals to provide a clear guide to the structure of prices in an industry in which there is considerable variation in costs, the task of setting tariff categories, especially for non-contracted supplies, falls on the regulator. It is at this point that inefficient prices and redistributional objectives come into play.

One of the way monopolies make excess profits is through discriminatory pricing—pricing not on the basis of cost of services but rather on the ability to separately price different classes of consumers. Regulatory systems do the same thing but not always with the objective of maximizing profits. Under the pressure of political and other demands, the tariff structures of most regulated monopolies have evolved into a complicated pattern of cross-subsidies which usually bears little relationship to real costs. In both developed and developing countries, these cross-subsidies have grown to the point where it

is difficult to achieve even the "average" price objectives. Often industrial or commercial users subsidize the more numerous residential consumers. Peak use is usually subsidized by off-peak users; rural users by urban users; a few special industries or consumer groups by everyone. In recent years, particularly in the U.S., a new class of cross-subsidies has been introduced to achieve environmental and other social objectives. The end result is that most systems wind up with tariff structures that have little to do with costs and with few incentives to manage the system so that costs are minimized.

The information systems are similarly distorted. If there are no "time-of-day" charges, then there is no incentive to collect the information. If plants are not dispatched on the basis of short-run marginal costs, this information will not be available. An integrated monopoly has little incentive to collect information on the various parts of the system, particularly if pricing decisions do not take into account the costs of the different parts of the service. In the U.S., for example, the information collected has more to do with accounting rules, regulatory requirements, and the tax structure than with economic costs of the different services.

These type of pricing systems put an enormous burden on regulation. As the cross-subsidies get more and more complicated and as more and more conflicting social objectives are introduced, the overall objective of achieving both efficient production and consumption of the services provided, is lost. As the cost of this type of regulatory environment has become obvious, new attempts have been made to come up with pricing rules that focus on efficiency rather than the redistribution of benefits.

One of the most promising of these is where the regulator starts with existing prices and returns and, in exchange for the freedom to adjust prices within tariff categories, the monopoly is expected to lower average prices by some annual percentage. This has been particularly popular in telecommunications (U.K. and U.S.) where the rate of technical progress has produced dramatic declines in cost over time. The principle is simple, the monopoly is encouraged to improve efficiency by being allowed to keep, for some fixed period of time, the gains that arise from these improvements.

It is not without its problems; the determination of the annual adjustment factor and the length of time to which it will apply is not a simple matter in practice. Its application in the power sector has been discussed, but as of the moment, it has not been implemented in any significant system. The pricing formulas used in Chile come close; efficiency is promoted by basing prices on "best practices" and if, for a period of time, a firm can better this, it can keep the gains. Probably the reason why these cost plus or minus systems have been slow to take hold in the power sector is that likely direction of changes in costs is less obvious than in the telecommunications sector, and the existing pattern of cross-subsidies is so well entrenched that attempts to change them too quickly will generate substantial opposition.

INVESTMENT DECISIONS: Providing an adequate framework within which investment decisions are to be made, is probably the most challenging area for regulation. Few do it well and it is in this area that the greatest pressures come from the political system. The large and often "lumpy" investments of energy enterprises, together with their complexity, invite the application of administrative discretion over simple rules.

External lenders have made popular the use of least cost planning techniques to produce the investment alternatives, but a great many discretionary assumptions must be made which offer ample opportunity for accommodating a variety of social and political objectives. One of the problems is that these techniques have been designed for public sector investments and generally require the existence of a monopoly in order to be implemented.

The private sector works with a different set of assumptions, particularly about risks, and is more concerned about risk minimization than cost minimization. Given different assumptions about risk, the private sector will make different decisions about what is the appropriate investment. The private sector, for example, will be unwilling to undertake investments that have long construction periods, eight to ten years, for example, for a hydro project, or that projects that have substantial construction risks, again, a high probability with hydro projects. Some countries have attempted to deal with these differences by having the public sector make the investment decisions and then inviting the private sector to compete for the project. But because of the risks involved, the private financing has not come forward with much enthusiasm unless there are substantial public guarantees.

Least cost planning techniques may be useful as an indicative planning tool but are incompatible with competitive markets. In the U.S., these

techniques have been used by private regulated monopolies in well-established market structures, but in developing countries it is unlikely that much private capital will be forthcoming unless the investors, rather than the government or its utility, make the fundamental decisions on what to build. As noted earlier, whoever makes the decisions must bear the risks, and if the private sector is not making the decisions, it will not assume the risks.

One of the arguments against allowing the private sector to make these fundamental decisions is that it will make the wrong decisions from the point of view of minimizing costs. The private sector will be "excessively" concerned with short-term considerations. Clearly these are different perspectives and in actual practice the results are somewhat mixed. In the U.S., a number of private utilities took long-run decisions in their investments in nuclear power. Although in retrospect, many of these decisions turned out to be costly, the implicit understanding between the regulators and the investors that all costs would be passed on to consumers, permitted the private investors to make "public" decisions. In the developing countries, the experience with least cost planning has not prevented either excessively costly decisions or the undertaking of high risk projects.[10] In other words, there is little evidence to support the hypothesis that decisions made by the public sector will necessarily be "right".

What are the alternatives? What type of regulatory framework is required to make sure the "right" decisions are made? How much "guidance" from the public sector will be acceptable to private investors? There are no clear answers to these questions. It will depend on the relationships and understandings that exist between the various parties involved. It should be kept in mind, however, that whatever role the public sector assumes in these decisions, it will have to bear the risks for those decisions.

ENTRY AND EXIT: A more promising direction for price regulation, particularly in the developing countries, is to promote clearer price signals through the utilization of competitive market forces. This will require major changes; at present, most regulation prohibits any form of competition. Until recently in Costa Rica, for example, even modest levels of auto generation were prohibited. For the most part, electric power has been reserved for a state monopoly and any competition has been actively discouraged. Overcoming this essentially hostile climate for competition and the power of the existing dominant monopoly to discourage entry will be a major challenge in any attempt to introduce a more competitive environment.

As noted earlier, the need for additional capital is the factor driving governments to look for additional resources from the private sector. The alternative of raising private capital for public entities through debt guarantees also has reached its limits. This has left government with no choice but to invite the private sector to participate in the management as well as in the financing of electric power. By inviting this private sector participation, the present regulatory structure with its protection of the state monopoly will have to be reexamined. Private capital, whether domestic or foreign, will be reluctant to enter this industry unless there is a clarification in the rules of the game. This will place a new set of demands on existing regulatory systems.

Most countries are trying to find a path of compromise between the present prohibitions on entry and the alternative of a completely unrestricted market. There is an understandable reluctance to give up all controls over what has been a tightly controlled industry. No country is willing to risk uncertain or unpredictable outcomes in such a politically and economically sensitive industry. For most countries, the issue is, what is the minimum amount of change required in the present system in order to attract the necessary capital to meet future needs. Improving efficiency is sometimes part of this goal.

In developing countries, the first tentative steps have been taken towards permitting a greater degree of competition. Limited entry has been permitted in a few countries into power generation. This has been tightly controlled with the government or national monopoly making most of the decisions. As noted above, this is closer to a more sophisticated system of public procurement than the introduction of true competition.

It is unlikely, however, to be more than a temporary start to a process of change. It is requiring governments to come up with a set of rules that change the status of the existing monopoly with commercialization and corporatization being the first steps. Without the

[10] Edward W. Merrow et al., "Understanding the Costs and Schedules of World Bank Supported Hydroelectric Projects," Energy Series Paper No. 31, The World Bank Industry and Energy Department, Washington, D.C., July 1990.

development of a more arm's-length relationship between the dominant monopoly and the government, it is not possible to write the new procurement rules for generation without introducing difficult to deal with moral hazard situations. Also, given the predominant public sector role in almost all of the investment decisions, private capital has been reluctant to come forward in significant amounts without extensive government guarantees. This is defeating one of the major objectives of these reforms—access to private capital without drawing on the credit of the public sector.

There is little option but to take the next steps; introducing competition in which the customers have a choice. In electric power, this means allowing the generators access to the customer. In its most limited form, this takes place in cogeneration plants where the generator is permitted to sell a part of the output to third parties, other than exclusively to the dominant monopoly. This immediately results in demands for TPA to transmission and distribution systems. This will be a particularly strong factor in most developing countries where industrial and commercial demands account for nearly 80 percent of total system demand. At this point, all pressures are to expand access and the regulatory system is forced into defining a new set of rules that further increases competitive pressures.

This evolution can be seen in the reform process as it evolves across countries. Indonesia and Malaysia were early entrants into the reform process and have restricted entry largely to the competitive procurement of generation services. The results have been limited and both countries are struggling with the next steps. Colombia and Ecuador are more recent entries into the reform process and are structuring their reforms to include from the start TPA as well as possibly the complete unbundling of services under different ownership.

Thus, experience is pointing in the direction of more radical reform in which competition is given a predominant role. Trying to write the rules of the game to control a process that is constantly changing may be more difficult than settling on an approximate end point and then defining the rules as required by the evolving situation. It may be better to focus the new regulations on promoting competition than on limiting the challenge to the existing monopoly.

ENVIRONMENT: Most energy transformation processes effect the environment. Increasing levels of public concern for these effects has introduced a new challenge for public regulation. This is particularly the case when these services are provided by public monopolies. It is extremely difficult for one arm of the government to impose restrictions on other parts of the government—consider the difficulty experienced by most public utilities in developing countries of collecting their bills from the defense establishment. In the U.S., the Department of Energy's management of nuclear plant producing defense related goods is an on-going environmental scandal. A typical response of a manager of a power plant in a developing country to the question of why the plant does not meet present environmental codes is that the necessary investments were requested in the budget, but the money was not allocated. The finance ministry will usually confirm that there were higher priority needs for the funds.

The challenge is to improve accountability. A key feature in improving this accountability will be the development of a more arm's-length relationship between the regulator and those being regulated. Corporatization is a start but will not be as effective as a clear difference in ownership. The introduction of real competition into the sector is an opportunity to improve the enforcement of environmental regulations. Private owners will respond to environmental requirements in order to protect their assets.

A separate regulatory group for the environment may be an unnecessary expense. Most of the major decisions affecting the environment and costs and prices are part of the investment decision. It is the investment decision that should be the major focus of any public regulation in a competitive environment.

Focusing public attention on the investment decision may be the most effective way of regulating this sector. At present, in most countries, the investment decisions are made by a relatively closed group of technicians, investors, and politicians. Regulation focuses on prices and more recently on the environment. Once an asset is in place, the costs and environmental impacts have been predetermined.

It is at the point of the investment decision that the type of open, more politically representative body, suggested by the analysis above can be most effective. At this point, the environmental and other social concerns should be entered into the cost benefit analysis of the project.

5. Finance

The last few years have seen a great deal of discussion in the need to use private capital to finance the power sector. In practice, in developing countries, the resource flows have been minimal. The bulk of private capital still continues to go into auto generation units that are part of industrial investments. At best, some U.S. $2 billion per year has flowed from external private sources and much of this has some form of government guarantee or is more akin to traditional supplier credits. Compared to the over U.S. $100 billion annual needs, this is a disappointing performance. Why is private capital so reluctant to put itself at risk? It is that country risks are too high?

No amount of financial engineering will produce gold from straw. In other words, unless the basic market, institutional, and regulatory structures are such that an investment will produce adequate returns relative to risks, the financial resources will not be forthcoming. Only the government with its ability to tax and provide guarantees, can underwrite unprofitable and excessively risky investments and still attract financial resources. The power sector with its traditions of consumer subsidies (estimated at over U.S. $100 billion a year in developing countries), price controls, and non-commercial objectives, seldom meets the basic requirements that would make it attractive for private investment.

5.1 *Basics*

Financial markets exist to intermediate between savers and investors. Savers typically wish the highest rate of return commensurate with as much liquidity as possible. Investors, on the other hand, wish to pay the lowest amount commensurate with the most commitment. A power company wishing to build an asset with a thirty-year life will seek financing for the life of the asset but few savers would be willing to commit their savings for this period of time, particularly in an underdeveloped financial market.

In most developing countries, even with high savings' rates, the capital markets are relatively underdeveloped. In many cases, this underdevelopment is the result of taxes and administrative controls on financial instruments and institutions. Commercial banks, for example, may have price controls on the interest rates they can pay savers which, in an inflationary situation, can amount to the confiscation of the savings. Compulsory reserve requirements or purchases of public debt may further erode the earnings of these institutions and the returns available to savers. Limits on interest rates for loans will lead to non-price rationing of available funds. Either public or private monopolies in the financial sector can limit the range of services available and risk taking of these institutions. A typical situation in many developing countries is that only one-third of savings is collected by formal financial institutions. Of this one-third, two-thirds is allocated by the government through various administrative means, leaving about 10 percent of total savings available for private capital markets. In contrast, in developed countries, nearly 90 percent of savings is allocated through financial markets.

The savings not allocated through financial markets tend to be used inefficiently. In some countries, the purchase of gold is a common way of holding assets. In others, it results in an inefficient investment process. It is typical, for example, for low-income urban dwellers to purchase and store building material in anticipation of home improvements—resulting in a large and inefficient build up of inventories. Farmers continue to invest in low-yielding crops because they have no alternative way of using their savings. It is common to find huge differences in rates of return on assets which can only be explained by the inability of savers and investors to find means for intermediating their different needs for security, liquidity, and returns.

If the domestic financial sector is in such an underdeveloped state, it will be extremely difficult for energy enterprises to tap into private savings. The funds available in domestic capital markets are small. In addition, the limited supply of savings available, not already preallocated by administrative measures, is subject to strong competitive demands that usually result in prices and terms that make it difficult to compete for those seeking financing for large amounts of longer-term capital.

Given the size of the energy sector and electric power in particular, it will be a large part of any capital market and the ability of these enterprises to obtain financing from private sources will move *pari passu* with the development of these markets. Without a growing and more open domestic capital market it will not be possible to restructure this sector so that a major portion of

its financing comes from the private sector. Many countries in this region are in the fortunate position to have started the process of reform in the financial sector thus making it possible to increase the amount of resources coming from financial markets.

5.2 *The role of external finance*

External financing can play an important role to assist in overcoming some of the limitations of domestic capital markets. To the extent foreign investors can be convinced to hold the assets of these institutions, it represents an important first step in establishing a market for these same assets. One of the major constraints in developing capital markets is the lack of attractive assets into which savers can put their resources.[11] The fact that external investors are willing to hold certain domestic assets is a first step in developing marketable instruments to represent these assets. These investors are taking the risk that the institutional and regulatory framework will produce an adequate return and if this in fact happens, these assets will become increasingly marketable.

One of the major disadvantages, along with many others, of recent build, own, and transfer schemes (BOTs, BOOTs, etc.,) is that there is no explicit consideration of using them for the development of marketable assets.[12] After some period of time, the plant is usually transferred to the existing monopoly and the market has no opportunity to develop experience in the buying and selling of these assets. If power enterprises are to be able to tap into domestic private savings, savers will need assurances that the assets they hold have some degree of liquidity. When the need arises to change, shift, or liquidate, their assets must be the expectation of a predictable market of buyers and sellers for these assets. This market will only develop with time and experience as buyers and sellers get accustomed to trading them.

It is in the interest of both the external investor and the country to structure the investments so that they produce marketable paper for the domestic capital market. There is no way a country can rely extensively on foreign savings to develop its energy sector. The sector is usually too large relative to the rest of the economy to be able to do this without running into serious balance of payments constraints.[13] It will have to utilize domestic savings for most of the needed resources. Using external savings to produce these marketable assets and then to develop a domestic market in which they are traded, is an important way of introducing savers to the assets of this sector.

For the foreign investor, the existence of a domestic capital market is an important means of covering risk. Investments in the energy sector are large and immobile. If the foreign investor has no way of liquidating his assets at any point in time, the investment decision must necessarily encompass the life of the asset—or the initial returns will have to be high enough to justify potential future losses. On the other hand, the existence of a domestic capital market in which the assets of the enterprise can be traded, lowers the risk to the investor. The market will provide the option of being able to adjust the amount of the asset the investor wishes to hold at any point in time. The investment decision (and the country risk) is thus not an all or nothing decision covering a long period of time, but one which can be adjusted to meet changing circumstances.

Usually, a foreign investor will not find a ready-made market for these assets. It will have to be created. Inviting local private capital to participate, even on a small scale, in the initial investment is not only good politics but a good means of familiarizing local sources of capital with the investment. Placing the assets with local capital in a form that encourages its trade is also important: it sets the stage for later sale of ownership or debt to the public in general.

This is seldom done. With a few exceptions, most potential foreign investors have come from the energy sector and tend to look on investments abroad as an extension of domestic

[11] In today's industrial countries, the early development of capital markets was based on a supply of assets created by investors in infrastructure, from the early turnpikes and canals to the later railways and power companies. By reserving these functions for the public sector and relying on tax revenues for their funding, many developing countries have stifled the development of capital markets.

[12] John Besant-Jones, ed. 1990. "Private Sector Participation in Power through BOOT Schemes." Energy Series Paper 33. World Bank, Industry and Energy Department, Washington, D.C.

[13] In the late 1970s and early 1980s, many Latin American countries financed their power sectors with external sources. When the inevitable debt crises hit, the countries found that between 15 and 40 percent of their external indebtedness was accounted for by the power sector alone.

investments. Taking on a domestic partner is simply a cost of doing business. Building a power plant in a foreign country is regarded as another part of their system in a more exotic location. In terms of risk, this is clearly not the case.

In moving abroad, the investor has become a venture capitalist, someone who takes risks in exchange for a higher rate of return. The issue is not one of whether he can build and operate a power plant in a satisfactory manner, but whether he can earn for his shareholders a rate of return commensurate with the risks taken. Risks will inevitably be higher, particularly in countries where the rules of the game are still in the process of development. The structure of the financial arrangements and the returns will have to reflect these risks.

The venture capitalist is in the business of building assets, but not necessarily in the business of running them for the rest of their economic life. Governments in most countries will not allow power enterprises over any length of time to earn higher than normal rates of return on investments. At best, a well-managed power plant ought to produce a respectable and predictable rate of return. This type of investment is more appropriate for institutional-investors such as pension funds and insurance companies who need to hold this type of asset.

How does the venture capitalist earn a sufficient return to compensate for the entrepreneurial risks taken? The answer is, of course, in the capital gains to be earned by producing a marketable asset. In most developing countries, there is a great shortage of quality assets in the marketplace and, properly structured, such assets should command a premium. In other words, the profit comes from producing an asset and structuring it in such a way as to make it desirable for others to hold.[14]

This means that as part of the initial investment plan, as much attention needs to go into the structuring of these assets as it does into the design and engineering of the plant. Information will be needed on the type of assets most likely to sell in the existing, albeit small, market. Usually, it will be difficult to sell long-term paper—most developing country markets will not take thirty-year bonds. On the other hand, paper with shorter terms, perhaps with various incentives such as rising coupon rates, to encourage holding rather than roll overs, may well be acceptable in these markets. Offering profit participation as part of the return on these assets may also encourage local interest. Over time, it will be possible to lengthen maturities and lower the costs as the market becomes more familiar with these instruments.

5.3 *The role of government*

The public sector has an important role in promoting these developments. Power investments will represent a large part of any capital market and it will not be possible for this sector to be much ahead of developments in the financial sector. Financial sector reforms, which move in the direction of making financial systems more competitive, more open, and less directed towards publicly controlled credit programs, is a necessary condition if the power sector is to have access to domestic savings. The power sector, because of its strong asset base and a predictable and growing demand for its outputs, can be an important instrument in supporting overall financial reform.

In addition, public policies which support the development of capital market institutions such as stock exchanges, rating agencies, accounting and auditing practices, etc., can all add to the willingness of the public to hold the assets of the power sector. The establishment of pension funds and various forms of insurance can provide the demand for the assets of the sector. In Chile, after privatization of the sector, over three-quarters of the assets of the power sector eventually wound up being held by these types of institutions. Mutual funds and other market-making institutions which are prepared to hold and trade these assets can add to their liquidity and acceptance by the general public.

5.4 *Finance and the implications for sector reform*

It would be unrealistic for countries to expect to attract large amounts of private capital in the immediate future from either domestic or external sources. The public sector, with support from the multilateral development banks and bilateral sources, will continue to be the main source of capital for some time to come. In most countries, the institutional structure is not in

[14] It is also a way of insuring that the project sponsors have a stake in the successful outcome of the project. In most BOOT projects, the project sponsors, usually contractors and equipment suppliers, bear little risk, and are taking most of their profits up front leaving most of the risk to the government and institutional investors.

place to make the sector attractive for private capital without the use of government guarantees.

The challenge of the immediate future is to set in motion the reforms that will make it possible for governments to relinquish their responsibility for financing this sector by the turn of the century. The broad direction of the reforms has been indicated above in the discussions of markets, institutions, and regulation. Increased competition, private ownership, and more open or transparent regulatory systems are all important ingredients of the process. The amounts of private financing likely to be available will depend on the speed and thoroughness of the reform process.

What are some of the steps that can be taken to move this process along?

CORPORATIZATION AND PRIVATIZATION: Many countries (Australia, Indonesia, Korea, and Thailand) have been considering changing the institutional structure to one in which the public monopoly, now operating as a state enterprise, is shifted to a corporate form of governance where the government holds all of the shares. The objective is to set up the power monopoly as a corporate entity subject to the normal commercial principles regarding accounting procedures, profit making, employment practices, etc.

This is only a first step. Subjecting the power monopoly to this form of governance is a necessary condition for improving the efficiency of the sector by establishing a greater arm's-length relationship between the government and the enterprise, but it is seldom sufficient. It is an opportunity to make some once-and-for-all changes in the enterprise, such as overstaffing or tariffs (Australia), but these changes are likely to be short-lived without taking further steps to introduce competition. As the Francophone experience with contract-plans has shown, it is extremely difficult to alter the relationship between these enterprises and the political system without utilizing the discipline of the marketplace. If an enterprise is owned by the political system, no matter how indirectly, any initial degree of independence is likely to be eroded over time.

Privatization is an important next step in solidifying some of the gains that can result from corporatization. In some countries (Malaysia), both steps have been taken at the same time. Even though the government may maintain a controlling interest, the existence of a group of shareholders with a vested interest in improving the performance of the enterprise, can act as a valuable counterweight to some of the excess of political control. In Chile, for example, the ownership of most of the assets by pension funds has created a strong institutional force for maintaining the profitability of the enterprises.

Whether privatization and corporatization take place at the same time or one follows the other will depend on country circumstances. In those cases where the public monopoly is performing reasonably well and is governed along commercial lines (Malaysia, Korea, and Thailand), it is possible to sell shares to the general public. In other cases (Indonesia and Bangladesh), the combination of performance and intrusive government management make it unlikely that the market would regard the shares as having much value. In these cases (Argentina), privatization has required the introduction of credible foreign management and ownership. This has usually been the case in the telecommunications sector. As in the U.K., it is possible for government to maintain a significant share holding for distribution at a later date when improved performance results in increased share value. To be effective, however, the new management must appear to be firmly in control.

In those instances where there is insufficient external interest in taking over the operations of the public utility (Bangladesh), consideration can be given to splitting up the present vertically integrated monopoly into more manageable portions. Spinning off local distribution into separate entities with some form of benchmark competition is one possibility. Where substantial parts of the system are isolated from each other (Indonesia and the Philippines), independently structured enterprises can be established. The better performing enterprises can then be privatized and, if they are small enough, taken over by local capital and management.

If the present system is large enough, each generating plant (or perhaps a group of plants) can be capitalized as separate entities and sold off after solid commercial performance has been established. Inviting existing interests such as labor and management to participate in the ownership of these plants can provide a powerful incentive for improved performance. It will be critical to establish, up front, the institutional arrangements between various parts of the now separately capital structured system. Soft budget constraints, for example, will undermine any pressures for improved performance. In India, the failure to establish an appropriate relationship at the time of dissolution between the

transmission part of the system, the large generators, and the state distribution systems has simply shuffled the unpaid bills from one entity to the other.

PUBLIC SECTOR FINANCIAL SUPPORT: In most countries, the public sector will have to continue to provide financial support until appropriate private-sector financial institutions are developed. How this financial support is provided, however, can make a difference to the speed and effectiveness with which these institutions are established. Covering the deficits of these institutions through transfers from the government budget, the soft budget constraint, is probably the worst way. No potential marketable instruments are created and financial discipline will be weak. Crediting these contributions to increases in the government's ownership of capital in these enterprises, fools no one.

Public funding of individual capital projects is also a problem. By earmarking funds for specific projects the government removes from the enterprise much of the responsibility for prudent management of investment selection and the construction process. The dismal record of the sector in making poor investment decisions followed usually by substantial cost overruns is attributable to a combination of poor management and political pressures to understate both risks and costs.[15] Once a government is committed to fund a project rather than an enterprise, it will find it difficult to back out, regardless, of how badly the project turns out (Yacireta and Argentina).

Better alternatives are to require the enterprise to specifically structure its capital requirements in a way that it creates debt instruments and ones that are linked to the overall profitability. In most cases, government will have to underwrite these instruments (India) and they are essentially another way of utilizing limited public credit. But, if the paper can be made attractive enough, particularly if it can be linked to enterprise performance, it is possible that markets independent of the public credit can be gradually developed. Setting and enforcing institutional limits on access to the limited public credit markets can enhance financial discipline and provide a measure of management performance (U.K.).

Utilizing more effectively the limited amounts of public credit available can be an important instrument in promoting competition and strengthening the development of an arm's-length relationship between the government and the dominant monopoly. By specifying each year the amounts available and then requiring both the public sector and potential new entrants to compete, can provide another way of both developing financial instruments and improving the allocative efficiency of public funds. The banking sector and financial intermediaries can supervise the disbursement of these funds and, after some period of successful experience, may be willing to underwrite some risks on their own account.

USE OF GOVERNMENT GUARANTEES: Whether the funds are disbursed directly from the government budget or are in the form of guarantees to financial institutions and other debt holders, they represent the use of scarce public resources. Many governments would like to limit the calls by the power sector on these resources. As noted above, it is unlikely that governments, in the immediate future, can expect much capital to be forthcoming without these guarantees. Nevertheless it may be possible to structure these guarantees in ways that encourage the development of capital markets and increase the leverage exerted by limited public money.

Most guarantee schemes have focused on debt. The World Bank, for example, encourages co-financiers to come forward by structuring the debt so that it takes on the risks of later maturities and commercial banks and other lenders nearer-term maturities. A number of industrial support programs provide public guarantees for only a portion of the debt with commercial or private lenders expected to bear some portion of the risk. Similar programs can be applied to the power sector. It will be important for the government to indicate up front the amounts and terms of its guarantees and inviting private participants to compete within an established framework of rules.

In addition, some consideration can be given to using public guarantees to cover income rather that debt risks. Investors in the power sector have expressed concerns about the level of risk inherent in power purchase agreements where no record of compliance or enforcement is available. They may have faith in the intentions

[15] E.W. Merrow and R.F. Shangraw, Jr., with S.H. Kleinberg, L.A. Unterkofler, R. Madaleno, E.J. Ziomkoski, and B.R. Schroeder. 1990. "Understanding the Costs and Schedules of World Bank Supported Hydroelectric Projects." Energy Series Paper 31. World Bank, Industry and Energy Department, Washington, D.C.

of government or the national utility to live up to the agreements, but express understandable caution on the ability of government to follow through in a timely manner.

Governments are notoriously slow payers. Coordinating complex bureaucracies is always a problem: the central bank, for example, may not release foreign exchange as it is required. Lack of timely legal means of resolving disputes can lead to costly delays. All of this means that even when investors have confidence in the general viability of a project, they must build in substantial allowances for the risk of poor administration of the agreements.

One means of offsetting these risks is for the government to guarantee the flow of income for some fixed period of time rather than the debt of the project. If, for example, the income from a project is expected to be US$2.5 million a quarter, than an escrow account of US$20 million, to be drawn on if the national utility or the central bank are unable to meet their obligations on time, would cover two years of income. This escrow account could be held externally if foreign exchange has been an issue. The guarantee of a predictable income stream for at least two years would provide investors and their creditors with time to sort out problems without endangering the cash flow. To the extent these funds are used or not used, it would provide both investors and the government with a strong signal on the effectiveness of the system.

The multilateral development banks: These institutions are not likely to provide much more money for this sector than they have in the past—in aggregate, about 7 or 8 percent of total needs. They have indicated a willingness to enter into a partnership with their customers to assist in the process of reform in this sector.[15] The existence of a well-articulated and agreed-upon program of reforms, supported by these institutions can be an important element in attracting additional capital and laying the foundation for future capital market developments. Channeling these resources through financial intermediaries rather than direct loans can assist the financial sector in developing a working relationship with the power enterprises.

6. Conclusions

The reform of the power sector is an extraordinarily complex task. Without a major program of reform, few countries will be able to attract the necessary capital to insure that this most convenient form of energy is available to support the process of economic growth. Few countries can afford the waste and the resulting environmental damages of today's inefficient systems.

Yet reform is unlikely to come from within the enterprises themselves. These institution are the result of the political compromises and understandings of the past decades. Change will require a new set of compromises and a new understanding between the enterprises, government, and the consumer; it will require a coordinated effort on the part of all parties to deal with the interrelated issues of markets, institutions, regulation, and finance. No one party has the ability to undertake significant changes without the agreement of all.

This makes reform a political process. It is not simply a matter of changing the legal structure of the enterprises (corporatization), or coming up with new financial engineering techniques (BOTs and BOOTs), or elaborate pricing rules (cost minus). It is about changing the way society regards this business. Is it to be an instrument of high state policy or is it to be just another industry, albeit an important one? The industry has matured: growth and changes in technology make it possible to treat this industry within a more normal commercial structure.

The political process will have to define the pace and content of reform.[17] This paper has raised some of the issues that will have to be considered in these discussions. Some of the contents of the process are:

1. The need to move from markets dominated by monopoly to ones where a greater role is given to competition.

[16] *The World Bank's Role in the Electric Power Sector: Policies for Effective Institutional, Regulatory, and Financial Reform*, A World Bank Policy Paper, The World Bank, Washington, D.C., January 1993.

[17] Few governments have much experience in managing the process of reform. I have attempted to draw up some rules based on experience in *Implementing Reform: Strategy and Tactics*, paper for the Ministers' Conference, Overcoming the Crisis of the Electric Power Sector in Latin America and the Caribbean Countries, Mexico, September 1991. The failure of most reform efforts is almost always the result of the failure to establish the necessary political base. Thus the first rule is communicate: care must be taken to explain the reasons for reform in terms that can be understood and appreciated by the general public.

2. The need for government to step back and become a regulator rather than an owner or operator.
3. The need to consider institutional development within a broader context that governs the way in which individuals, business, and governments, interact with each other.
4. The need to develop domestic capital markets to support the financial needs of the sector.

The pace of reform is critical. A slow and stately pace may produce few benefits and much opposition. Managing a gradual process of reform may be more institutionally challenging than undertaking bolder and more deliberate changes. The availability of financial resources from the private sector will be linked to the pace of reform. Under the best of circumstances, private savings will be slow to materialize until confidence and experience is gained. If these resources are to be made available for next decades massive requirements, a start will have to be made today.

Financing private sector participation in the Indian power industry

by
The World Bank[1]

The private power development initiative launched two years ago by the Government of India (GOI) has no doubt aroused significant interest among potential private developers and investors, both domestic and foreign. A large number of project proposals are under consideration and a few of these have now reached or are moving towards the conclusion of power purchase agreements (PPAs). While the selection of project sponsors has, in most cases, not been on a competitive basis, and while some key policy issues—such as foreign exchange cover for return on capital equity, or the provision of government guarantees for backstopping the obligations of State Electricity Boards (SEBs) or in respect of sovereign risks—are not fully resolved, project sponsors having concluded PPAs are commencing to arrange the financing of their projects.

From the pace of progress to date, it may be reasonable to envisage private power projects of a total capacity of approximately 5,000 MW to be undertaken in the coming five years. This will involve an investment of around U.S. $7 billion giving rise to a financing requirement of around U.S. $1.4 billion per year during the next 5 years. It is likely that 60 percent of such outlays will be in foreign exchange and the balance would be raised domestically. Though the current government guidelines permit a debt-equity ratio of 80 percent/20 percent for such projects, it is likely that potential lenders will insist on a lesser reliance on debt. A ratio of 70 percent/30 percent would, thus, seem more realistic (and in keeping with the proposals made by some potential project sponsors). On this basis and keeping in view the GOI guidelines which limit foreign debt to twice the foreign equity, the financing structure of the annual requirements could be as shown in Table 1.

Under the current government guidelines, the level of foreign equity can of course go up to 100 percent. It may be noted, however, that Development Financial Institutions (DFIs), for extending term loans to the projects, would require the company's securities to be listed

[1] This paper has been prepared by a World Bank team, led by Mrs. J. Chassard, Senior Financial Analyst and consisting of Ms. F. Mazhar, Financial Officer, and Messrs. M. Gulati, Financial Analyst, W.S. Tambe and J. de Vera, consultants.

Table 1
Structure of the annual financing requirements

	U.S.$ million	*Rs. crores*
Equity		
• Foreign	280	840
• Domestic	140	420
Subtotal (30%)	420	1,260
Debt		
• Foreign	560	1,680
• Domestic	420	1,260
Subtotal (70%)	980	2,940
Total	1,400	4,200
Memo item:		
Financing requirements		
• Foreign (60%)	840	2,520
• Domestic (40%)	560	1,680
Total	1,400	4,200

on the stock market. One of the listing requirements of the stock exchanges, viz., at a minimum 25 percent of the capital issued should be offered to the public, would necessitate issue of domestic capital by the project companies.

There is no doubt that the generally poor financial health of the SEBs, in most cases the prime purchasers of the energy to be produced by the private power projects, is a source of major concern for both the project sponsors and their prospective financiers. Accommodating such concerns by guaranteeing SEB power purchase payments cannot provide the basis for sustaining the momentum of the private power initiative in the long run, even though this may be required for bringing to fruition of the first few private power projects. Given the SEBs' poor track record of meeting their commercial obligations and their fast deteriorating financial performance, there is a risk that these guarantees may be invoked, creating an unbearable burden on the already constrained financial resources of the states and the central government. It is therefore imperative that the risk of non-payment by the SEBs be met by transforming them into financially viable entities rather than underwriting their obligations by way of state government guarantees and GOI counter-guarantees. Demonstrating its commitment to reform, the SEB is of paramount importance for the successful implementation of the initiative already taken by the GOI to encourage private investment in the power sector.

There is a wide range of issues relating to the financing of private power projects. The key ones having direct bearing on the financing are discussed below. There are, however, two important general issues which can also affect the viability and financibility of such investment. These are:

- **The process of selection of promoters and the appraisal of their proposals.** Many of the Memoranda of Understanding (MOUs) issued in the initial batch of projects have been issued to promoters without adopting any competitive or screening process. In several cases, the MOUs were not based on well-developed project proposals. Investors and lenders to these projects would find it difficult to support projects of promoters lacking in financial, technical, and managerial capabilities or to fund projects which have not been properly appraised.
- **Limitations imposed by government guidelines on project design.** The government guidelines assume that all private power projects will operate as base-load stations and the tariff structure has been designed to help ensure project viability in such circumstances. There may be circumstances in which private power investment would be of greater economic benefit to the SEBs, if such investment were made in power plants which could be best used for peaking or at intermediate load factors. This would be possible only if the government guidelines on the tariff are made flexible enough to accommodate such operational regimes.

1. Issues related to external financing: foreign equity

Foreign investors are likely to tie up with foreign equipment suppliers for part of the equity requirement. To some extent, it may be possible to mobilize foreign equity from bilateral and multilateral sources such as the Canadian Development Corporation, the Asian Development Bank (ADB), and the International Finance Corporation (IFC). Other potential sources of foreign equity, such as non-resident Indians as well as offshore institutional investors, may also need to be explored. However, the interest of foreign developers in any project and the level of foreign equity input would ultimately depend on the extent to which their concerns are addressed.

Some of these concerns relate to foreign exchange risk protection in terms of their equity investment[2] as well as the nature of convertibility assurances provided relating to dividend repatriation. A clear statement of GOI policy on this matter would be necessary to enable the developers, lenders, and utilities to evaluate the project risks.

2. Issues related to external financing: foreign debt finance

2.1 *Export credit*

The balance of the foreign currency financing requirements would be in the form of debt finance, the major portion of which is likely to be mobilized from Export Credit Agencies (ECAs). The extent of the availability of export credits would vary with the country from where equipment is expected to be sourced. These countries could conceivably be the U.S., Germany, U.K., France, Japan, Italy, Korea, Sweden, and Switzerland. The extent of ECA support would depend on the specific agency's overall country limit, the supplier in question, the project, and calls on the ECA's support for other projects. Foreign equipment suppliers would thus play an important role in this financing effort. The mobilization of this foreign debt finance, estimated at around US$560 million, with ECA support, may not be impossible in itself for India. However, clearly there will be competing demands from other power projects in the public sector as well as for projects in other sectors, which is likely to limit the amount available for private power.[3]

In addition, indications are that the Indian DFIs' and commercial banks' balance sheet capacity would be considerably stretched if these institutions were required to provide guarantees to ECAs as well as fund the bulk of the domestic financing requirements of power projects, particularly as prospects of mobilizing debt in the domestic capital markets would seem fairly limited.

Many ECAs in the past have been reluctant to consider lending on a "project security" basis, and instead have relied on guarantees from public sector institutions such as the State Bank of India (SBI) and the Industrial Development Bank of India (IDBI). However, recently, in some developing countries, export credits have been mobilized on the basis of "project security".[4] Therefore, project sponsors should be encouraged to approach ECAs on this basis rather than on the basis of "unconditional" public sector guarantees in order for project risks to be shared between the public sector, lenders, and investors. ECAs may not be prepared to accept the project completion risks, but this could be addressed through risk sharing with commercial bankers and contractors.

2.2 *Commercial finance*

Indications are, that under current market conditions, it would be difficult to access the international markets for medium-term finance, both for the amounts and the maturities required by the private power program without some form of credit enhancement from multilateral institutions. Credit enhancements could take the form of the IFC 'B' Loan program,[5] the ADB complementary finance scheme, or the ADB's and the World Bank's Loan Guarantee Program.[6] Commercial banks may, however, be prepared to consider shorter-term construction finance but on the basis of firm "take out" assurance from acceptable parties such as ECAs.

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[2] Foreign exchange protection of the return on equity through the payment of higher dividend only on "foreign equity" are not permitted by Indian law. It appears that differential treatment between domestic and foreign equity, even if allowed by law, is likely to affect capital market support for such projects.

[3] Based on World Bank consultations with the Berne Union, indications are that about US$750 million could be available annually for the power sector, for both private and public investments.

[4] Project Security: The financing of a particular project on a "stand alone" basis where lenders primarily look to the future cash flows of the project for debt service and where the security of the loan is supported through a security package which provides for the apportionment of project risks between the Sponsor/Borrower/Guarantor and various other third parties such as power purchaser of the product through a series of contractual undertakings and support agreements.

[5] IFC "B" Loans: Complementary financing from commercial banks within the framework of a specific "umbrella" protection in terms of IFC being the "lender of record".

[6] ADB and World Bank "ECO" Guarantee Schemes: Both ADB and the World Bank have Guarantee Schemes in place which can provide support for medium- and long-term commercial bank loans, or other forms of borrowing from private lenders in the capital markets.

3. Issues related to domestic financing

Given the various constraints noted earlier on the availability of external finance, it is clear that the developers would need to raise a significant part of their capital requirements from the domestic capital and credit markets.

4. Domestic capital market

4.1 Equity

Of the estimated gross domestic savings of Rs. 130,000 crores (U.S. $43 billion) in FY92/93, the corporate sector raised, through the primary capital market, Rs. 18,000 crores (U.S. $5 billion) while the Unit Trust Corporation (UTI) and others raised Rs. 7,000 crores (U.S. $2 billion)[7]. Of this, 88 percent was by way of equity or convertible debentures while 12 percent was as bonds or non-convertibles. Even the latter were issued with an equity "sweetener" since straight non-convertibles had no takers. There is a clear investor preference for equity as it has an upside, has provided speculative gains in the past, and is considered as a hedge against inflation. Thus, it does not appear difficult to raise the domestic equity for a private power program of the size envisaged.

4.2 Debt

At present, there is little liquidity in the secondary debt market because all the debt is held by institutions such as UTI, Life Insurance Corporation of India (LIC), General Insurance Corporation (GIC), and mutual funds.[8] However, with the inflation scaling down, and equity market stabilizing to more reasonable price earning levels, the investors' interest in the debt could revive if there was a secondary market providing liquidity. In the absence of liquidity in the secondary market, the issuers have to provide liquidity through buy-back arrangements or by providing a put-option.

The normal tenor of the debt instruments is 7 to 10 years with redemption from the 7th through the 10th year. Private power projects, whose tariffs would allow depreciation of only 5 percent per annum, may not be able to service the debts of this tenor and would need to issue longer-term debt. The size of the market can be marginally expanded by permitting charitable trusts, public trusts, pension, and provident funds to invest in power project debentures but the individual investors, whether through the mutual funds or on an individual basis, may be attracted to the debt market if there is sufficient liquidity provided by the market. It is therefore important that, in the absence of active secondary market for debt, some mechanism is put in place to provide liquidity to the debt issued by the power projects which can be achieved in a variety of ways like support to the market makers, providing larger number of call and put options on the debt instruments, and funding the required back-stopping arrangements.

5. Domestic credit market

In so far as the private power projects are concerned, the credit market is limited to four Indian financial institutions (IFIs): IDBI, Industrial Credit and Investment Corporation of India (ICICI), Industrial Finance Corporation of India, and SCICI (started by ICICI for financing shipping industry but has expanded its mandate to finance infrastructure projects); for very limited amounts LIC, and commercial banks (CBs).

5.1 IFIs

IFIs limit their exposure (which includes term loans, guarantees, and underwriting commitments) to no more than 25 percent of their net worth, to a single project and to 10 percent

[7] UTI, invests approximately 40 percent of its resources in equity and 50 percent in debt of 3 to 7 years, and 10 percent in short-term liquid debt. In FY92/93 it invested Rs.10,000 crores (US$3 billion) which included the fresh capital raised in the market and accruals from past investments.

[8] Of the annual accretion, LIC and GIC are permitted to invest no more than 15 percent in corporate sector loans, debentures, and equity. In FY 1992-93 these institutions raised about Rs.8,000 crores (US$2.3 billion).

(maximum permissible limit being 15 percent) of their total liabilities to any sector. In FY92/93, IFIs provided loans of Rs.16,000 crores (US$5 billion) to the corporate sector; and their lending is expected to grow at an annual rate of 20 percent. IFIs are therefore not expected to provide more than Rs.1,000 crores per year (US$300 million) to private power projects. However, after the first few projects, as the IFIs reach their sector exposure limits, the additional headroom would be available only to the extent of annual growth and repayments by the already financed power projects.

The rates of interest on term loans of IFIs are in the range of 15 percent to 17 percent, more than prevailing market rates, but are expected to be reduced. The maximum tenor of their loans is 10 years including grace for construction.

In addition to extending loans, IFIs may be called upon to provide guarantees to foreign lenders, which would increase their exposure and further limit the availability of domestic finance to the projects. Alternatively, if foreign lenders are to be encouraged to consider providing support on a "project security" basis, the IFI practice to lend against security of a charge on physical assets could adversely impact on foreign lenders' project security arrangements.[9] Therefore, the possibility of IFI participation in the "project security" on a *pari passu* basis with the foreign lenders needs to be explored further. This may obviate the need for the IFIs to extend guarantees and can thereby expand their funding capacity for power projects.

5.2 *Commercial banks*

CBs will be called upon to meet the very large working capital requirements of the projects, provide guarantees in support of the foreign lenders, and underwrite public issues of capital by the projects. CBs would seem to have sufficient capacity to meet the working capital requirements of the private power projects. Their underwriting capacity, however, is not expected to be significant (US$200 million for the entire corporate sector).[10] Therefore, the IFIs may have to meet the bulk of the underwriting needs of the projects. As regards guarantees, foreign lenders accept only SBI and IDBI guarantees. SBI, in turn, syndicates counter-guarantees from other CBs. However, inter-bank guarantees are not excluded for determining exposure and capital adequacy requirements of the banks, which further constrains their already limited capacity to issue guarantees and also increases the cost to the customer.

6. Issues related to security arrangements

6.1 *SEB risk*

As stated earlier, the SEBs' ability to pay the private projects regularly in terms of the PPAs, is a major source of concern for the promoters, other equity investors, as also the prospective lenders, both domestic and foreign. The suggestion that these payments be secured by making "escrow" arrangements on collection from by "designated" industrial customers is seen as causing problems for other domestic creditors in providing finance for other SEB activities, such as working capital requirements, which are met by CBs on the basis of a floating charge on current assets, including receivables from the same industrial customers, who provide 60-70 percent of the SEBs' revenues. By the same token, this may not prove acceptable to foreign lenders who may not necessarily have the wherewithal to assess the risks of individual industrial consumers or even the guarantees of state governments. Currently, foreign lenders, both ECAs and CBs, are prepared to accept guarantees of certain public sector financial institutions such as SBI or IDBI. However, as noted earlier, this requirement would place a further burden on these institutions, in addition to the role that they would be expected to play in the provision of local finance to power projects. Unconditional guarantees of public sector financial institutions provided for ECA support would run counter to the objectives of the private power program, which calls for a sharing of project development risks between the public

[9] IFIs lend against security of charge on assets, and do not accept "project security" with "negative lien" on assets since such lending is considered as "unsecured" and affects their balance sheet.

[10] The CBs are permitted to extend underwriting to the extent of 1.5 percent of incremental demand and time liabilities [which in FY92/93 was Rs.36,389 crores (US$12 billion)].

sector and the private sector; thereby reducing the financial obligations of the public sector.

Current indications are that foreign lenders, in the absence of the above guarantees, would expect GOI counter-guarantees in support of the PPAs for them to consider power projects as "bankable propositions". Of course, the nature of GOI counter-guarantees under a PPA would differ from normal GOI unconditional sovereign guarantees of debt in support of public sector projects, as the obligation of GOI would be limited and could only be invoked if the developer delivers in compliance with the terms of the PPA, and if both the SEB and the state government in question default on their obligations. In this case, the project developer would assume the construction and operational risks of the project and GOI the payment obligations of the SEBs.

In order to ensure consistency of policy on the security issue, the form of these guarantees would need to be carefully assessed in the light of balance sheet constraints of the respective public sector financial institutions, the scale of the proposed private power initiative, and the exact nature of the undertakings required from GOI and its likely impact on GOI's external debt. The key question of "security undertakings" would need to be carefully reviewed as any ad hoc decision on this issue may set a precedent which could prejudice future efforts for financing the private power projects. In any event, fundamentally, SEB risk would best be mitigated by an improved, robustly profitable performance of the SEBs and this would need to be given a continued high priority. Therefore, it will be desirable to ensure that any underfinancing of SEB risk does not weaken the incentive for SEBs to improve their financial performance.

6.2 *Fuel supply risk*

The assurance of steady fuel supply of the agreed quality (and adequate compensation in case of failure) is another concern for the investors as also lenders. The current supply contracts offered by the Gas Authority of India, Ltd. and Coal India are seen to be one-sided and unsatisfactory in this regard. Lenders would expect that the fuel supply term coincide, at a minimum, with the term of the debt finance.

In case of coal, assurances of satisfactory transport arrangements by Indian Railways will also be necessary. Here again, foreign investors and lenders, are likely to seek some contractual assurances by the GOI as the owner of these undertakings.

7. Conclusion

It would appear that the private power program calls for large investments that may not be adequately met by existing market sources or the equity sources of the project developers alone. While the question of adequacy of the domestic equity and debt markets will need to be addressed for the whole program, in the initial phase, the availability of foreign currency finance could become the critical factor in determining the success of the program.

The repayment periods of the debt which such projects can expect to raise from various sources (both domestic and foreign) are also likely to pose problems for their viability. Assuming tariffs are set per GOI guidelines and the plant operates at a normative plant load factor of 68.5 percent, the private power projects will experience cash flow deficits for the first 5 years. This condition will create additional difficulties in obtaining financing for the projects. It would be unrealistic to assume that this could be addressed by allowing the tariffs to be increased to significantly higher levels. Thus, it is essential to seek ways by which the debt profile of these projects could be improved and their viability ensured in the initial critical years of the project.

Several financial institutions interested in financing private power projects in India have indicated a need for multilateral institutional support in the form of either ADB, IFC, or World Bank intervention, both to assist in catalyzing the resource mobilization effort in the financial markets and in providing the necessary long-term funds to supplement existing funding sources. World Bank support (i.e., access to World Bank resources with far longer maturities than any alternative sources currently available to India) could also be important in terms of ensuring that the external debt service burden on the country does not become too onerous for a program that will not generate any direct foreign currency earnings. This can also serve as a means of providing potential cofinanciers with the necessary comfort with respect to projects which have been appraised by the World Bank

and which may be implemented with World Bank support. The World Bank is currently exploring the best possible options for providing such assistance and supporting the financing of individual private sector projects while keeping in line with the government's priority of mobilizing private financing resources.

Closing statement

by
Heinz Vergin, Director
India Department
The World Bank

Mr. Minister, Honorable Chairman of the Finance Commission, Professor Chelliah, Ladies and Gentlemen:

The various contributions to this conference and the high-quality dialogue that has taken place have shown that there is now a widely shared diagnosis that, after making major contributions to India's national development, the power sector has not kept up with the needs of the economy. The conference has also identified various options for improving the sector's performance. In this regard, we have taken special note of Mr. Pawar's presentation on "SEB Issues and Options" which was further enhanced by his forceful answers to the searching questions posed to him in his capacity of Chairman of the NDC Subcommittee on Power Sector Issues.

Overall, I am taking away from this conference a considerable measure of encouragement and hope that India's policy makers at the Center and in several states will sooner rather than later address themselves to the urgently needed structural reforms. What I have heard would point to an emerging structural reform agenda that seems to come under six major headings: four address the need for bold structural changes and two relate to symptoms of structural problems that need to be addressed before any new structure can be made to work.

Broadly, the emerging reform agenda seems to comprise:

1. **Establishment of a policy framework** which, through reinterpretation and amendment of existing legislation, provides increased operational autonomy, commercial, corporate-type management of all generation, transmission, and distribution of electric power.
2. **Implementation of tariff reform** to set rates based on long-run marginal cost with transparent provision for all subsidies via the budget and gradually reduced reliance on cross-subsidization of power users within the balance sheets of the utilities.
3. **Establishment of a regulatory framework** consistent with the reforms under (1) and (2) above and designed to induce efficient resource use in the context of cost-based tariff setting. The door would be left wide open however to achieve efficiency through growing competition rather than regulation.

4. **Design and implementation of bold state-level power sector reform** with due regard to the fact that electric power is a concurrent subject under the Constitution. The design of these state-level structural reforms would however be guided by the reform framework set under (1), (2), and (3) above.
5. A start needs to be made by all units on financial workouts regarding payables and receivables. This would be needed to facilitate commercial management of power sector assets based on meaningful balance sheets and income statements. It is also prerequisite to gaining access to market-based funding.
6. Forceful reduction of distribution losses which are undermining the payments morale of the paying customers.

This near- and medium-term structural reform agenda which now seems to be gaining wider acceptance could, when translated by your government into a specific, time-bound action plan, provide the basis for continued and stepped up World Bank support for India's power sector.

Specifically, the support which we would offer could take the following form:

1. Continuation of time-slice lending for the priority investment programs of National Thermal Power Corporation and Powergrid.
2. Continued support for Power Finance Corporation.
3. Continued support for your government's renewable energy program.

and, as the new centerpiece of our assistance program:

4. Start of structural adjustment lending to support the boldest and, in the national context, most deserving **state-level power sector reforms** fast-disbursing IBRD funds.
5. Expert assistance in design and implementation of the government's medium-term reform agenda and in the exploration of India's longer-term options. In this context, we would see merit in supporting periodic conferences and seminars like this one to enlist support for the government's reform program.

In the medium-term, we would also be prepared to offer:

6. Technical and financial support for demand-side management.
7. Technical and financial support for the environmentally more sustainable operation of India's existing and new generating capacity.
8. Imaginative use of the World Bank's guarantee powers to catalyze improved access to capital market funds from inside and outside India the stronger, more solvent sector units.

In money terms, this support could, subject to availability of quality projects and programs and subject to improved performance of the existing IBRD power portfolio, gradually result in annual IBRD lending to India's power sector of up to $800 million. Moreover, we are confident that the government's pursuit of bold sector reforms would unlock considerable co-financing and other bilateral support which could be expected to match the projected volume of IBRD lending.

Mr. Minister, with the policy analyses and sector analyses already performed by many of the highly qualified, forward-looking participants in this conference, the World Bank's assistance program which I have outlined is entirely feasible if your government embarks on a bold structural sector reform program which resets the national policy framework in the manner already contemplated by your government, and enlists the participation of a few forward-looking and courageous state governments which are prepared to set an example for the rest of the country.

Mr. Minister, as only friends could and would dare, we in the World Bank urge you to bring the power sector into the broader national structural reform program. The stakes are admittedly very high, but so are the benefits to your nation.

We are prepared to be a resourceful, unobtrusive partner in this undertaking.

Conference Agenda

Friday, October 29

	Opening Session	
14:00 - 14:05	Welcome	A. Dua, Conference Director, Ministry of Power
14:05 - 14:10	Opening Remarks	H. Vergin, Director, India Department, World Bank
14:10 - 14:25	Inaugural Address	N.K.P. Salve, Union Minister of Power
14:25 - 14:40	Presidential Address	B.R. Bhagat, Governor of Rajasthan
	Session 1: Background for Power Sector Reform	Chairman: N.K.P Salve, Union Minister of Power Moderator: R. Vasudevan, Union Secretary of Power
14:40 - 15:10	The Situation of the Power Sector: The Need for Reforms	T.L. Sankar, Principal, Administrative Staff College of India
15:10 - 15:40	How does the Indian Power Sector Compare Internationally?	D. Butcher, Managing Director, Butcher & Associates, former New Zealand Minister
15:40 - 16:15	Discussion	
16:15 - 16:30	Break	
16:30 - 17:00	Conceptual Framework for Power Sector Reform	A. Churchill, Principal Advisor, World Bank
17:00 - 17:45	Discussion	
17:45	End of Session	

Saturday, October 30

	Session 2: Challenges	Chairman: Mohd. Qureshi Governor of MP Moderator: R. Vasudevan
09:00 - 09:45	SEB Issues and Options	Addressed by S. Pawar, Chairman of the Committee on Power, NDC
09:45 - 10:15	Discussion	
10:15	End of Session and Break	
	Session 3: International Experience	Chairman: Mohd. Qureshi Moderator: R. Vasudevan
10:30 - 11:30	China Experience	Y. Rongsi, Vice President China Electricity Council
11:30 - 12:00	Discussion	
12:00 - 12:15	Break	
12:15 - 13:15	Argentina Experience	M. Zaghini, General Director for Financial Aid and Cooperation, Secretariat of Energy
13:15 - 14:30	Lunch	
14:30 - 15:30	United States Experience	B. Tenenbaum, former Associate Director, FERC
15:30 - 16:00	Discussion	
16:00 - 16:15	Break	
16:15 - 17:15	United Kingdom Experience	R. Witcomb, Director of Corporate Planning, National Power
17:15 - 17:45	Discussion	
17:45	End of Session	

Sunday, October 31

	Session 4: Commerciality, Competition and Sector Reform	Chairman: R. Chelliah, Fiscal Adviser to the Union Minister of Finance
09:00 - 09:20	Commerciality of SEBs	T.L. Sankar
09:20 - 09:40	Design of the Reform Process	A. Churchill
09:40 - 11:00	Panel Discussion:Principal Issues and Reform Options of the Indian Power Sector	
11:00	End of Session and Break	
	Session 5: Where do we go from here?	Chairman: N.K.P. Salve
11:15 - 12:45	Next Steps	R. Vasudevan
	The World Bank's Role	H. Vergin
	Valedictory Address	K.C. Pant, Chairman, Finance Commission
	Closing Remarks	N.K.P. Salve
12:45	Word of Thanks	A. Dua

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