PREFACE

The ERC Act of 1998 enjoins the CERC to promote competition, efficiency and economy in the electricity industry. It also requires that the CERC will aid and advise the central government in the formulation of tariff policy, which shall be fair to the consumers and facilitate mobilisation of adequate resources for the power sector.

The tariff of generating companies owned or controlled by the Central Government, the tariff of other companies with a composite scheme for generation and sale in more than one state, the transmission of energy by POWERGRID and the inter-state transmission of energy, including tariff, are within the regulatory mandate of the CERC. These transactions are identified in the consultation paper as "bulk" or "wholesale" transactions.

The immediate objective of tariff regulation should be the establishment of a predictable and fair system, which rewards efficiency and discourages the cost plus approach to rate making. Consequently, the Commission proposes to establish tariff regulations, which simulate competitive conditions. Performance targets benchmarked at the level of industry best practice and incentives linked to their achievement is one such option which will induce utilties to continuously increase efficiencies. Disaggregation or unbundling of facilities for tariff determination is another option to induce competition in some segments of a market, which is otherwise dominated by a few producers. Through such methods, the Commission can try to ensure that the dominant position of central generating stations or of the public sector monopoly, which is currently designated as the Central Transmission Utility, is not exploited.

The Commission expects to achieve a long-term trend of electricity prices, declining in real terms, through the introduction of efficiency enhancing incentives and competition in supply, where feasible. The introduction of competition, in the supply of electricity and in the supply of fuels, has resulted in such real price declines in other countries. Fuel is the single major cost for thermal stations. Thermal power is dominant in India. For significant reduction in bulk/wholesale electricity tariffs, input costs must come down. The benefits, of such rationalisations in bulk power are expected to assist state level regulators to further rationalise retail tariffs.

Tariff regulations must be comprehensive and must support the establishment of commercial conditions acceptable both to the supplier and the buyer. The enforceability of contracts and agreements, particularly regarding the payment of dues, binding producers and buyers alike, is one such area requiring attention. The definition of shared responsibilities for grid management must be accompanied by the enforcement of strict penalties for grid indiscipline. Transparent decision making procedures for ensuring "least cost" investments, particularly in transmission, where economies of scale restrict competition, is another area which directly impacts tariff setting and will therefore be reviewed by the Commission.

This consultation paper does not seek to categorically state the mind of the Commission on tariff setting. However, it expresses views with the intention of eliciting a response from stakeholders. The Commission would like to see changes in some crucial areas of tariff setting. These include the determination of tariffs on the basis of outdated norms, the lack of certainity in the tariff payable at the time the transaction is entered into, the poor payment record of customers, the rampant indiscipline in the regional grids which results in extreme frequency and voltage excursions, fluctuations and the absence of incentives for continuous improvements in efficiency. It proposes to address these issues in its orders.

This paper describes the history of bulk power tariffs in India, the policy framework within which the Commission has to function, an exploration of what competition and markets would mean in the electricity industry and the principles and alternative methods for the determination of generation and transmission tariffs. For convenience, it highlights the primary issues separately, in an executive summary. These are issues concerning tariff setting which require resolution and on which the Commission seeks the views of stakeholders.

The Commission hopes that this paper will generate widespread discussion and comments, and welcomes written comments from members of the public, constituents of the electricity industry and other experts. The Commission proposes to arrange conferences at the headquarters of the Regional Electricity Boards, at Bangalore, Mumbai, Calcutta, Shillong and Delhi in October 1999 to enable greater interchange of views. The intention of the Commission is to announce the principles on which it will approach tariff determination, during the year.

(S. L RAO)
CHAIRPERSON

Dated: September 15,1999.

CHAPTER 1

1. ELECTRICITY TARIFF - HISTORY AND CRITIQUE

1.1 Introduction

This chapter traces the changes in the legal provisions governing electric power tariffs and discusses the processes and methodologies adopted over time for tariff setting till the formulation of the Electricity Regulatory Commissions Act. 1998 (ERC Act).

1.2 Indian Electricity Act, 1910

The legal provisions for the regulation of tariffs of power utilities can be traced to the Indian Electricity Act 1910 (IE Act). However, in keeping with the perceptions of the times there was no attempt at being prescriptive by specifying, either the principles, or the methodology to be followed for tariff setting, beyond enjoining that tariffs must be non discriminatory and allow a reasonable return to the licensee.

1.3 Electricity (Supply) Act, 1948

1.3.1 The first attempt to closely regulate monopolistic power utilities by defining the basis on which tariffs could be charged was made in the Electricity (Supply) Act, 1948 (E(S) Act). At the time there were two types of entities in the power sector; Licensees under the IE Act and State Electricity Boards (SEBs) created by the E (S) Act.

1.3.2 Schedule VI of the E (S) Act prescribed the methodology to be followed for the determination of the tariffs of power utilities which were Licensees under the IE Act. This is a detailed cost plus methodology where the rate of return on the capital invested is regulated and a cap is imposed on the clear profit of the licensee. A detailed explanation is provided in Annexure I. In the case of Licensees it has worked satisfactorily from the viewpoint of financial viability of the utility.

1.3.3 The SEBs were expected to supplement the efforts of the private Licensees. Section 59 of the E (S) Act therefore provided for the basis of tariff determination of the SEBs. As originally formulated, it simply enjoined the SEBs to adjust their charges from time to time so as not to conduct their business at a loss after accounting for subventions received from government. It also envisaged that there may be need to meet expenses on operation an maintenance from capital to be sanctioned by the state government. This was clearly in sharp contrast to the existing provisions for Licensees who were left free to recover charges as appropriate from the consumers. Act 23 of 197 amended Section 59 of the E (S) Act to specify that the tariff was to be so adjusted so that SEBs earned at least a surplus, after accounting for all subventions and costs, including tax. The rate at which such surplus (defined as income less expenditure, including interest and depreciation) was to be recovered was left to be specified by the state government. Act 16 of 1983 further amended the section to the form in which it stands till today. SEBs were required to so adjust tariffs so as to earn a surplus (defined as income less all costs, including interest on debt) of at least 3%. This floor rate for the generation of a surplus was possibly necessary to safeguard against the continuing deterioration of the financial conditions of the SEBs. Surplus is defined as a return on the value of the fixed assets of the SEBs in service at the beginning of the year. State governments could also specify a higher rate for the generation of surplus. Generally states did not actually do so and SEBs have been unable even to generate the specified minimum surplus.

1.3.4 Till the establishment of central generating stations under the central government power companies from the early 1980's, the industry was dominated by vertically integrated SEBs and private Licensees. SEBs could purchase electric power from any person under the provisions of section 43 of the E (S) Act on terms as agreed between the contracting parties. However no defining principles were available for tariff setting and tariffs for individual stations were decided on the basis of mutual consent between the generator and the consuming SEBs. The absence of mandatory norms for tariff setting are said to have led to delays in settlement of commercial terms and required extensive negotiation de novo for every station. This was perceived to be inefficient. Consequently the central government constituted a committee under the chairmanship of Shri K.P.Rao Member (E&C) CEA to recommend alternative methods for the determination of generation tariffs of central stations.

1.4 K. P. Rao Committee

1.4.1 The recommendations of the K.P. Rao Committee can be regarded as a landmark in the history of tariff regulation in India. Annexure II reviews the recommendations in detail. While the entire set of recommendations, which were very wide ranging and proposed a substantial change in the methodology of tariff setting, were not implemented by the government, four recommendations, which were implemented, significantly altered the tariff setting methodology.

Firstly, the concept of "deemed generation" was introduced which compensated generators, in the event of a station being available but forced to back down due to system constraint.

Secondly, the concept of two-part tariff, comprising fixed and variable charges respectively was accepted, though it was only implemented in part.

Thirdly, efficiency enhancing changes were effected in the existing incentive structure. Till 1991, the single part tariff was calculated such that full recovery of fixed costs was assured at a PLF of 62.8%. Generation below thss target level penalised the generator on the recovery of fixed cost, since the tariff got proportionately reduced. Conversely, generation above 62.8% resulted in significant excess revenue. The formula adopted post 1991 limited both the incentive and disincentive for recovery of fixed costs. The incentive beyond 68.5% PLF was lower than before while even with nil generation 50% of the fixed cost was recoverable.

Fourthly, for the first time operational norms were determined for station heat rate, auxiliary power consumption, specific oil consumption. More importantly, the norms were challenging relative to average performance levels at the time and hence laid the basis for performance based ratemaking.

1.4.2 Act No 50 of 1991 introduced Section 43A of the E (S) Act, which specifies that in the case of government owned generating companies the tariff would be decided by the state or central governments whichever owned the company. Tariff was determined on the basis of operational norms and PLF as determined by the CEA while the rates for depreciation and reasonable return were to be notified by the central government. It was under these provisions that some of the recommendations of the K. P. Rao Committee were notified by the central government and came to be used in tariff determination of central stations.

1.5 Norms for Independent Power Producers

1.5.1 The Amendment Act No 50 of 1991 had also changed the definition of "generating company" to include privately owned generating companies. Accordingly a fresh set of norms were notified by the central government on March 30, 1992 to determine tariffs for both thermal and hydro generating stations to be set up by the Independent Power Producers (IPPs) in the private sector. These have been subsequently modified from time to time. Five primary changes were introduced in the determinants of tariff.

Firstly, the recovery of fixed costs was linked to deemed PLF (defined as PLF plus Deemed Generation) thereby making a departure from the past wherein the recovery of fixed costs was linked initially to the PLF achieved and then the deemed PLF. While deemed PLF is arithmetically the same as Availability, the latter has to be declared ex ante and requires the utility to commit to a certain level of preparedness for generation, while the former is a ex-post concept. The adoption of availability as a performance target for the recovery of fixed charges was therefore a natural culmination of the process of rationalisation begun by the K.P.Rao committee.

Secondly, the incentive structure was further revised. In the case thermal generation the deemed PLF for full recovery of fixed charges was fixed at 68.5%. For hydropower the target availability was 90% (subsequently reduced to 85% in 1998). An incentive in the form of a increase in ROE of upto 0.7% points for every 1% point increase in deemed PLF (Availability in the case of hydro) was determined along with penalty calculated as a prorata reduction in the recovery of fixed cost for deemed PLF / Availability below the target level.

Thirdly, along with the increase in the rate applicable for the central generators from 10% to 12%, the Return on Equity for IPPs was fixed a 16% per annum.

Fourthly, against the notional debt equity ratio of 50:50 for central generators, the debt equity ratio for IPPs was revised and the minimum level of equity fixed at 20%. The minimum stake of the promoter to be held as equity was fixed at 11% of the total capital. A cap was imposed on financing from the Indian Financial Institutions at 40% of total outlay (which has subsequently been relaxed).

Fifthly, upto 100% foreign equity was permitted with foreign exchange risk protection.

1.5.2 With effect from November 1, 1998 (and later for licensees as well), the central government revised the return on equity for central government generators also from 12% to 16% without making any change in the notional debt equity ratio of 50:50 applicable for such stations.

1.6 Transmission Tariffs

Separate provisions for transmission tariff do not explicitly exist in any the electricity laws. This is not surprising since unbundled transmission did not exist till the establishment of POWERGRID in 1989. In fact POWERGRID treated as a generation company under the definition provided in the E (S) Act. The assets of POWERGRID, the sole central government transmission company, were transferred to it from NTPC and NHPC. Tariffs have been notified by the central government on the basis of techno economic approvals of investment given by the CEA. Consequently the notification dated December 17, 1997 was the first attempt to formalise the methodology of tariff setting. It prescribes a single part tariff comprising all costs on account of interest on outstanding loans and working capital, return on equity, depreciation, O&M expenses as per norms and income tax. The full cost is recoverable at an availability of 95%. An incentive is given in the form of increase in ROE at the rate of upto 1% point for every 1% point increase in availability. A debt equity ratio within the norm of 80% maximum and 20% minimum has been used for POWERGRID while the rate of ROE is the same as for generation.

1.7 Conclusion

The cost plus approach has been predominant in tariff setting in India. A significant departure was seen in 1991 with the part adoption of the recommendations of the K. P. Rao committee, which introduced the concept of performance based rate making and bench marking of operational standards. This approach has helped to induce the regulated entities under this regime to significantly improve their performance and reduce operational costs. Unlike the international experience of such schemes, the tariff regime has been very stable. Some may comment that the tariff regime should have been reviewed more frequently than was done to ensure that the resultant efficiency gains are shared with the consumers. In 1998, prior to the coming into effect of the ERC Act five sets of norms for tariff setting were in force. One set of norms, specified by schedule VI of the E (S) Act, determines the tariff of Licensees under the IE Act which are all in the private sector. The second set of norms under section 59 of the E (S) Act determines the tariff of SEBs. The third set of norms specified by the central government under section 43 A(2) of the E (S) Act determines the tariff of central stations. The fourth set of norms under the section 43 A(2) specifies the tariff for IPPs. The fifth set of norms specifies the tariff for POWERGRID the sole central transmission company. There is a fair degree of commonality in all the five sets of norms though they are not identical. The effectiveness of all the five sets of norms, in providing incentives for continuous improvements in performance standards, can be questioned. Their relevance in the light of changes in the macro environment and the rapid evolution of the Indian Power Industry may also be in doubt. However it is well established that each represents an evolutionary stage which improved the effectiveness of the regulatory regime in place at the time that these norms were formulated. It is just as clear that significant adjustments are now required if the positive trend, in evidence since 1948, in the evolution of tariff regulation in India is to be maintained.

CHAPTER 2

2. THE POLICY FRAME WORK

2.1 Introduction

2.1.1 The policies of the government draw their legitimacy from the Constitution of India, Acts of Parliament and common law principles. Within the broad framework of policy, governments have traditionally made rules, regulations and passed orders, which translate the policy directions into practice. Where, in addition, governments, either directly or indirectly through wholly owned companies, have entered into commercial transactions, like production and sales or the provision of other services, the distinction between policy and practice gets further blurred. The policy maker, doubles up as the service provider, thereby sometimes, losing the sense of unbiased detachment; which is necessary for effective policy formulation. It is in recognition of this dilemma, that the ERC Act has sought to externalise substantial portions of regulatory responsibilities to independent regulatory commissions. The regulatory commissions are bound to be guided by the policy directions of government involving public interest. However they have the independence to frame the strategy, devise the tactics and define the instruments which are to be used to implement such policy directions. This chapter reviews the policies of government in relation to the electricity sector. The supportive strategies, tactics and actions that must be taken by those agencies charged with the implementation of policies, are dealt with in other chapters.

2.1.2 The policies of the central government have traditionally assumed the need for an intrusive form of regulation. Investment decisions, siting of projects choice of technology and fuel, volume of production, methodology of tariff determination, quality of supply and service and the nature of commercial contracts have all traditionally been decided by the government, or one of its associated entities. Developments in the policy framework can therefore, be fairly closely associated with, both the successes and the failures, of the past five decades. Government policy evolved in three major phases. The first phase from 1948 to 1975, can be categorised as the growth of state level investments in the power sector and the decline of private investments and management. The second phase from 1975 to 1991 marks the ascension of the central government utilities in generation and transmission. The last phase commences from 1991. This year marks a turning point in the policy of the Central Government, with respect to the power sector. Till that year, the policy had been oriented towards central planning and public investment led growth in capacity. From 1991, in line with the general trend of economic reform and liberalisation, government policy has evolved to a more market friendly approach. It now aims at achieving efficient and sustainable growth in supply, to meet demand, through the provision of price incentives and reliance on competition in supply, through induction of the private sector.

2.2 The policy framework 1948 to 1975

The thrust towards the public sector, in the first two decades after independence, resulted in the establishment of State Electricity Boards (SEBs) under the Electricity (Supply) Act, 1948. These entities gradually subsumed the operations of the private licensees, operating at that time under the Indian Electricity Act, 1910, as these licenses expired. SEBs were vertically integrated utilities with a commitment to enlarge the customer base for electric power, particularly in the rural areas. SEBs functioned well during this period. They introduced electric power, which till then was an urban privilege, to an expanded consumer group including farmers, small industry and small consumers in remote areas. However, by the late 1970's investment levels were perceived to be lower than those required to meet the goal of power on demand. SEB's were not able to generate the surpluses required to feed the growing investment needs of the sector focussed on supply side solutions for meeting demand. Direct investment in generation and transmission, by the central government was the solution devised for this problem.

2.3 The policy framework 1975 to 1991

The latter half of the 1970s and the early part of the 1980's saw the creation of generation companies, like NTPC and NHPC, owned by the central government. In 1986 the Power Finance Corporation was created to supplement the budgetary resources of the central government. In 1989 the transmission assets of the NTPC were separated into a new central government owned company, known as POWERGRID today, which is entrusted with the task of developing the regional and national grid. However the need for fiscal discipline and the increasing pressure on budgetary resources of the central and state governments in the 1990's induced a review of the financial viability of the public investment led approach followed till then. While the central government had managed to retain remunerative tariffs for its companies the states were not able to mirror this while setting retail tariffs. Electric power supply was perceived almost as a public good. Several states supplied free power to farmers. Most states did not meter small consumers or control the ever mounting transmission and distribution losses. The growing fiscal burden of subsidies and the constrained budgetary resources set the scene for the dilution of the public investment led growth model. This was as true for the power sector as it was for most infrastructure.

2.4 The policy framework 1991 and beyond

2.4.1 The government identified private investment and management as being necessary partners for sustainable and efficient growth of the power sector. Facilitating policy changes aimed at rapid investment in generation followed which evoked a flood of interest from the domestic and foreign private sector. However the uncertain financial viability of the distribution sector, which was primarily with the SEBs, proved a major barrier in converting the interest of the private sector into projects on the ground. The lack of private investment, despite the existence of facilitating policies, focussed attention on the need for regulatory reform.

2.4.1.1 Regulatory reform

The Electricity Regulatory Commission Act, 1998 establishes an independent regulatory commission at the center and enables the establishment of regulatory commissions in the states, to introduce competition, efficiency and economy in the power sector, safeguard the consumer interest and improve the quality of supply and service. These bodies function in a quasi-judicial manner and have the powers of civil courts. They consist of members, selected in a prescribed manner, which ensures fair and impartial selection of professionally competent, upright and committed people who serve the commissions for fixed tenures. The government has thereby externalised a substantial part of the entire process of regulation of the power sector, from the government. It has done so with the hope that greater professionalism, transparency of process and procedure and the participation of a larger group of stakeholders in the decision making process, will result in informed, unbiased, efficient, fair and commercially sound decision making. Tariffs, conditions of supply and service and in many cases, licensing of investments and operations, are within the purview of the regulatory commissions. Any tariff policy guidelines, issued by the government shall be characterised by fairness to consumers and aim to facilitate mobilisation of adequate resources, for the power sector.

2.4.1.2 Market reform

Amendments to the Indian Electricity Act, 1910, made in 1998 have established the Central Transmission Utility (CTU) at the center and the State Transmission Utility (STU) in the states. Any company, owned by government, can be the CTU which is charged with the responsibility of undertaking inter state transmission of energy, discharge all functions of planning and coordination and supervise and control the inter-state transmission system. Similar provisions exist for the states. The government has designated POWERGRID as the CTU. While private investments in transmission are possible, these private operators will function under the supervision and control of the CTU. They will transact with the CTU and not directly with the consumer. Hence a structure has been created which ensures the dominance of a public owned transmission utility. In generation, the dominance of the central generators continues, but is sought to be controlled through the regulatory process. However, the Mega Power Policy of 1998 does facilitate large generation projects in the private or joint sectors, which will over time compete with central generators. To reduce the cost of bulk power, to increase the availability of power in the bulk power market and thereby to establish a national market for power, the central government has incorporated the Power Trading Corporation Limited (PTC) in 1999. The PTC will assist in the development of mega projects, which will supply power on a regional or national basis. Economies of scale and preferential tax treatment are expected to make bulk power available at economical rates. The projects are insulated from payment risk since they will sell power directly to the PTC under a composite scheme for the generation and sale of power in more than one state. The policy framework is several steps away from competition in bulk supply. However, there is a clear departure from the past, in that a simulation of competitive conditions has been attempted.

2.4.1.3 Optimisation of supply profile

Concerned by the declining shares of hydropower in the total generation of electricity, the central government formulated the Hydro Power Policy in 1998, which sought to reverse this trend. This policy proposes the levy of a cess on energy consumption for financing the growth of hydropower. It also prescribes a reduction in the availability target for full recovery of fixed cost from 90% to 85%. It recognises the higher risk and uncertainty inherent in hydropower and seeks to adopt risk mitigation strategies so as to make the sector attractive for private investment. It prescribes a preferential tariff for hydropower in recognition of its suitability as a source for peaking power. It recognised the undeveloped potential in small hydro and sought to transfer all hydro projects of 25 MW and below to the Ministry of Non Conventional Energy for specialised assistance and promotion.

2.4.1.4 Institutional reform

The Central Electricity Authority is expected to continue to discharge its functions in the areas of national planning and technological support to the government. However the intrusiveness of its decision making has been progressively reduced. Since 1995, the investment limit for thermal, generation below which the projects do not require the techno-economic clearance of CEA, has been progressively raised from Rs. 100 crore to Rs. 5000 crores allowing most investment decisions to be taken on purely commercial considerations and as per the business plans of individual developers. However to ensure that such investments are least cost the limit for projects which do not go through the competitive bidding route is lower at Rs. 250 crores. With the deletion of section 43 A (2) of the E (S) Act, CEA will no longer have a statutory role in the determination of operational norms for generation projects. All the functions regarding dynamic, short term planning of the transmission system, with a time span of one year and under have been now vested with the CTU for the interstate transmission system and the STU for the state level transmission system. CEA will however continue to make the five to twenty year national plans and integrate the transmission plans of the states and the center. Through amendments made in 1998 to the Electricity (Supply) Act, 1948, the role of the Regional Load Despatch Centers (RLDCs) has been strengthened in view of the urgent need to improve grid operations. RLDCs will be managed by the CTU and will be in control of the real time operations of the inter-state grid while State Load Despatch Centers have mirror functions for the state grids. This will involve a reallocation of the existing functions being performed by the Regional Electricity Boards (REBs) which till now have been the primary regional entity for exercising control over the regional grids.

2.5 Conclusion

The policy changes effected by the central government since 1991 are supportive of the overall objectives of improving the efficiency and economy of the power system. With this new phase, policy determination has evolved into an exercise in creating the enabling environment within which specially empowered institutions, like the regulatory commissions, the CEA, the CTU and STUs have to function creatively, to translate objectives into achievements. Many of these functions are new and precedents are unavailable to assist the institutions charged with executing these functions. Policy support, as for example those necessary for structural change, may therefore be required to make these institutions more effective. Prescriptive rule making is on the decline while indicative planning and directional regulation is being adopted. However clearer policy directives, as for example with respect to the role of the private sector, the scope for introducing competition through structural change, the role of the regulatory commissions in the areas of environmental regulations, in deciding input costs for power and in the establishment of incremental capacity are required. The final stage of evolution, under the reform program currently being implemented, envisages greater reliance on markets to allocate resources and to induce improvements in efficiency. However significant institutional strengthening is indicated, before the Indian power sector can become competitive and market oriented.

CHAPTER 3

3. MARKETS AND COMPETITION

3.1 Introduction

Competition in supply and consumer choice are the hallmarks of a functioning market. These are relatively new concepts for the electric power industry worldwide. Where they have been introduced as in the UK, Norway, parts of the US, Argentina and Chile the industry had necessarily to go through a major restructuring to create the enabling conditions. Vertical unbundling separating generation, transmission and distribution, at the basic level, and horizontal unbundling of generation and distribution, creating multiplicity of players within each of these industry segments, have become the standard reform components. This is the reform package, which has already been adopted in India. At the central level, transmission was segregated from generation in 1989. In most states this task has been initiated under the reform programs started since 1995. These reform programs, in addition, target the separation of distribution from transmission. Orissa, Haryana and Andhra Pradesh have replaced the erstwhile SEB with unbundled entities. Orissa has privatised thermal generation capacity and the distribution companies, which succeeded the SEB. However even here monopolies remain in existence. Open access to the grid is not permitted. The second level of reforms, aiming at the development of power markets, will need to introduce a market for bulk power, open access to the transmission grid and choice of supplier for the retail consumer. Constraints in transmission capacity, imbalances in demand and supply, inadequate metering arrangements and irrational tariffs are some of the barriers to an early introduction of these markets.

3.2 Market potential

3.2.1 Demand

Low per capita consumption of electric power, an increasing population, high income elasticity of demand, unexploited potential for energy efficiency improvements and the potential for economic growth, in the 7% to 8% per annum range, are the primary drivers for growth of electric power demand in India. Power generation capacity of the utilities in 1998-99 was about 93,000 MW while energy generation was around 450 billion units. Since 1990, the average annual growth of generation has been around 7% p.a. while growth in peak demand has been 4.5%. Demand growth without commensurate supply has kept electricity in a sellers market. Peaking shortage is 11% while energy shortage is 5.5%. The CEA estimates power demand in 2012 at 176,647 MW and energy demand at 1058.4 billion units[1]. However, control of theft at the retail level and tariff, reflective of costs, would be the factors which would influence the future of demand profile.

[1] 15th Electric Power Survey, CEA.

3.2.2 Supply

Unexploited hydro potential is primarily concentrated in the North and the North East and Coal, primarily, in Central and Eastern India. Since domestic resources of gas and oil are limited these energy resources need to be imported. There is considerable potential for the import of hydropower from Nepal and Bhutan and the import of gas or gas based electric power from Bangladesh.

3.3 Products

The Indian market for power is relatively nascent and underdeveloped. At the central level even the primary distinction between generation capacity and energy supply is yet to be defined through a suitable two-part tariff. This unbundling of generation services has however been given effect to in the case of IPPs. Other products like reactive power, black start facility and spinning reserve or emergency power are not priced separately today. In transmission also no distinction is made between availability of capacity and transmission of energy. Individual transmission lines are not priced separately. In states no distinction is made between transmission and bulk supply. Distributors pay a bundled price for the supply of bulk power to the monopoly transmission utility, comprising the cost to this utility of purchasing bulk power from generators and its own transmission charges. Similarly retail consumers pay a bundled charge to the distributor, comprising the cost to the distributor of purchasing bulk power from the monopoly transmission utility, its own distribution charges and the cost of metering, billing and getting payments from the retail consumer. Ancillary services like customer's load management, special services for interruptible loads (switching advice to local non-conventional generation resources at peak load period), energy counseling etc. are unknown.

3.4 Trade in power

3.4.1 The uneven spread of primary energy resources and the relatively well endowed status of neighbouring countries like Nepal and Bangladesh create the potential for trade in power. India already imports power from Bhutan while initiatives are in place also in the case of Nepal. India can similarly be attractive market for gas or power or both from Bangladesh. More immediate possibilities for trade present themselves in the domestic market. The table below highlights the regional variations in the demand and supply gap existing today.

Table: Regionwise, Ownershipwise capacity and energy supply

Region	Installed Capacity (MW)	SEBs / SPSU (MW)	CPSU (MW)	Pvt. Sector (MW)	Energy Kwh Short. %	Peak MW Short. %	Shortage Period with Freq. < 49 Hz % of time
South	23100 (100%)	16583 (71%)	4755 (21%)	1762 (8%)	10.8%	12.3%	85.3%
West	28665 (100%)	18120 (63%)	5513 (19%)	5032 (18%)	5.1%	21.4%	24.4%
North	24981 (100%)	13115 (52%)	11841 (48%)	25 (0%)	4.8%	9.7%	27.3%
East	14798 (100%)	6942 (46%)	6771 (46%)	1195 (8%)	-1.0%	8.9%	5.2%*
North East	1714 (100%)	959 (56%)	730 (43%)	25 (1.5%)	2.4%	5.8%	
TOTAL**	93790 (100%)	57237 (60%)	28514 (32%)	8039 (9%)	5.5%	11%	NA

Note : % may not total to 100 due to rounding error.
** This includes installed capacities in various islands
Source: Estimated from data available in CPA & Ministry of Power.

3.4.2 The energy surplus in the Eastern region (surplus period of Eastern and North-Eastern regions together is 60.7% with over frequency beyond 51Hz.), the emerging surplus in the Western Region and the prevailing shortages in other regions provide a ready opportunity for trade in power. Even at a future date when shortages will not constrain demand in any region, opportunities for trade will present themselves due to the diversity of demand patterns across states. Variations in rainfall patterns, temperature, lifestyles and load profile provide opportunities for the surplus capacity at off peak in one region to meet peak or "shoulder" demand elsewhere. The primary constraint today is the non-availability of transmission capacity and the credit worthiness of the buyers. Despite these constraints bilateral trades do take place between states within a region and across regions. It is estimated that around 5% of the total energy supplied is traded. With the growth of regional grids this trend will increase. POWERGRID intends to increase its transmission capacity to 70,000 MW by 2012. This will represent around 29% of the estimated national generating capacity of 2,38,000 MW at that time.

3.4.3 International experience suggests that trading can evolve either between integrated utilities, as in the case of the US, or as a consequence of the unbundling of the sector with open access to transmission. Trading between integrated utilities has been taking place since 1996/97 in India also as a result of SEB's selling surplus power commitments to other SEBs. The open access model is also simultaneously in place. Central generators have been using the inter-state transmission facilities of POWERGRID and sometimes even the transmission facilities of an SEB to sell power to other SEBs. More recently the establishment of the Power Trading Corporation has heralded the entry of bulk power marketers who will buy power from generators and sell it to distributors. An informal or formal pooling arrangement has yet to develop. Till now short-term trades are "brokered" through the medium of the REBs, which being a comprehensive stakeholder group, bring surplus and deficit states together and ensures that transmission access would be available for the transfer. As the RLDCs gradually take over the task of operational control of real time operations, they could also execute this task. However, the composition of the REB forum is clearly favourable for its evolution into a forum for settlement of short-term trades. In the longer term, PTC, which would have gained experience in inter-regional sale of power, may become the appropriate vehicle for the establishment of a power pool for the settlement of short and long-term trades.

3.5 Institutional arrangements

3.5.1 Developed markets have a complex bulk power market structure comprising the following.

1. **Suppliers of bulk power** :

   (i) Merchant generators with no long term contracts,
   (ii) IPPs bound by long term contracts to specific buyers and
   (iii) Vertically integrated utilities in surplus areas.
   (iv) Power Marketers.

2. **Buyers of bulk power :**

   (i) Vertically integrated utilities in deficit areas
   (ii) Power Marketers who may buy from merchant generators or have long term contracts with IPPs or purchase the surplus

capacity of vertically integrated utilities for sale to others.
(iii) Integrated distribution and retail supply company.
(iv) Retail supplier
(v) Bulk consumer

3. **Infrastructure providers:**

(i) Power Exchanges, which provide a forum for posting prices, acknowledging and servicing buy/sell contracts, billing and settlement of trades.
(ii) Transmission Owners whom maintain and operate transmission lines and charge users of the use of the facility.
(iii) Independent System Operator which are responsible for scheduling, despatch and energy accounting.
(iv) Ancillary Service Provider
(v) Scheduling Coordinators

3.5.2 The Indian market structure is simpler as given below.

1. **Suppliers of bulk power:**

(i) Central generating stations like NTPC, NHPC etc.
(ii) IPPs or mega power projects, which are being currently negotiated.
(iii) Vertically integrated utilities (SEBs) in surplus areas
(iv) Power marketers like Power Trading Corporation (PTC) will sell to state level transmission companies or SEBs.

2. **Buyers of bulk power :**

(i) State level transmission utilities (GRIDCO in Orissa and AP TRANSCO in Andhra Pradesh) which buy in bulk and are monopoly suppliers to distribution companies.
(ii) Vertically integrated SEBs.
(iii) Power marketers like Power Trading Corporation (PTC) which will buy from the mega projects.

3. **Infrastructure providers :**

(i) POWERGRID and state level transmission utilities which provide transmission access
(ii) RLDCs which are currently managed and staffed by POWERGRID and function as ISOs for the regional pools though with limited functions. State level load despatch centers (SLDC) perform these tasks but in addition also perform the tasks performed by the REBs at the regional level.
(iii) Regional Electricity Boards (REB) which function as Power Exchanges for the regional pools, record and settle transactions and do energy accounting and settlement of trades.
(iv) Vertically integrated utilities which provide transmission and distribution networks.

3.6 The potential for competition

The regulatory impact of competition has yet to be felt in any substantive way in the Indian power sector. It is not surprising that there are multiple barriers to the development of competitive conditions. Some key areas are listed below.

3.6.1 Imperfections in the Indian Power Sector

(a) There are only a few suppliers in the bulk power market. The dominant generator is NTPC with around 20% of the national generation capacity and over 80% share of the regional availability in supply. In the states, the bulk of the

generation capacity is with the SEBs. The share of IPPs in state level capacity is less than 5%.
(b) There are no merchant generators in India. All IPPs have long term contracts, assuring recovery of full fixed cost and return on equity at 68.5% PLF. Some IPPs even have guaranteed offtake of power. The capacity of central generators is allocated to specific states under the Gadgil formula. Hence there is inadequate untied capacity to allow for open market operation.
(c) Schedule VI of the E (S) Act which has been used as a guiding principle for tariff setting for licensees and now has directional value for regulatory commissions, is essentially a cost plus regime. In the case of central generators, all costs on the basis of norms determined in 1992 are passed through and any efficiency gains are retained by the Company. There is therefore little incentive to shift to a more competitive market situation.
(d) POWERGRID's Inter regional transmission capacity at around 5000 MW is around 5% of the national generating capacity, though inter-regional exchanges of energy at around 7.3 billion units represent less than 2% of national consumption. In some areas transmission bottlenecks restrict free power flows thereby creating isolated power market pockets.
(e) Most regions suffer from chronic power and energy shortages. Allowing markets to operate under these conditions would result in the allocations of power on the basis of capacity to pay. This could significantly alter the demand, supply balances in States.

While these imperfections are unlikely to fade away in the short term a number of initiatives can be conceived off which would stimulate the development of competitive conditions.

3.6.2 Competition in Generation

(a) More market players are required to have effective competition. One way to simulate this gradually might be for each unit of a large CGSs to compete in the market place. For such competition, "ring fencing" of the accounts of each unit would be required to ensure that one unit does not subsidise another. This will introduce market rivalry for achieving efficiency, which can be beneficial to the customers and society in general.
(b) Increasingly, IPPs would need to be built as merchant plants, rather than based on long term contracts with states. For this to happen, private investors would need to be confident that a free market was in operation. Generators would want assurances that they would have open access to the transmission system and participate in the regional bulk power market.
(c) The central and state government owned entities might gradually divest their generating facilities.

3.6.3 Competition in Transmission

The Central Government has notified Power Grid Corporation of India Ltd. (POWERGRID) as the Central Transmission Utility (CTU). The CTU will transmit energy through the inter-State transmission system, plan and coordinate the inter-state transmission system, with other players in the power sector including CEA, and exercise supervision and control over the inter-state transmission system. The ownership and management of regional load dispatch centres (RLDCs) has also been given to the POWERGRID through an amendment of the Electricity (Supply) Act, 1948. RLDCs are to ensure integrated operation of the power system in the concerned region. Currently, POWERGRID wheels the power generated by the central sector generating units and delivers it to the SEBs/STUs. The Electricity Laws (Amendment) Act, 1998 envisages private investment by allowing transmission licensees also to construct, maintain and operate any inter-state transmission system. However they have to operate under the direction, control and supervision of the CTU. The legislative framework views transmission as a natural monopoly, and hence has given a dominant role to the CTU. The potential for competition is limited in transmission. However some of the following initiatives, which foster competitive conditions, are possible :

a. investments that reduce system losses and transmission constraints, allowing better competition between generators;
b. better transmission pricing signals for the location of new generation plants and reactive compensation for reduction of losses and constraints;
c. ancillary services like reactive power, emergency power, spinning reserve etc; which are neither priced separately nor provided adequately by the constituents.

3.7 Conclusion

Markets can produce significant efficiencies. There is no guarantee however that they will be immediately successful. Recent attempts to create markets in other countries have achieved limited success or have failed for a variety of reasons. This is not to say that markets should be avoided. However markets need a structural, legal and commercial base before they can achieve their full potential. Given the complexity of the issues involved, the necessary preconditions for successful markets and the low margins for errors in the system, it may be worthwhile to conceive of a regional implementation plan for the move to market determination of prices and quantities of supply. In this manner the efficiency and effectiveness of the proposed changes can be tested before they are applied to the national system. In any case the first priority before the Commission will be to extract the efficiencies possible within the existing system before moving to the next stage of market development. This strategy will also ensure that many of the preconditions like reduction of information asymmetry, creation of surplus capacity and institutional support which are necessary for market operation, are in place, before utilities and consumers are exposed to the discipline of the market. Gradualism with directional incentives will be the motif of the Commission's strategy for the move to markets.

CHAPTER 4

4. TARIFF SETTING PRINCIPLES, METHODS AND ISSUES

4.1 Introduction

This chapter reviews the legislative mandate for the functions of the Commission, with respect to tariff determination, the guidelines as available in the ERC Act or as given by government policy, the regulations formulated by the Commission, the key principles it intends to use for tariff design, the objectives, which it would like tariff policy to achieve and the primary issues before the Commission in executing its mandate.

4.2 Functions of the central commission

The CERC was established by the ERC Act of 1998. The functions of the Commission are defined in section 13 of the ERC Act and are reproduced below:

13) *The Central Commission shall discharge all or any of the following functions, namely :-*

> ***a)*** *to regulate the tariff of generating companies owned or controlled by the Central government;*
> ***b)*** *to regulate the tariffs of generating companies, other than those owned or controlled by the Central Government specified in clause (a), if such generating companies enter into or otherwise have a composite scheme for the generation and*

sale of electricity in more than one state;
***c)** to regulate the inter-State transmission of energy including tariff of the transmission utilities;*
***d)** to promote competition, efficiency and economy in the activities of the electricity industry:*
***e)** to aid and advise the Central Government in the formulation of tariff policy which shall be-*

> ***i)** fair to the consumers; and*
> ***ii)** facilitate mobilization of adequate resources for the power sector;*

***f)** to associate with the environmental regulatory agencies to develop appropriate policies and procedures for the environmental regulation of the power sector;*
***g)** to frame guidelines in matters relating to electricity tariff;*
***h)** to arbitrate or adjudicate upon disputes involving generating companies or transmission utilities in regard to matters connected with clauses (a) to (c) above;*
***i)** to aid and advise the Central government on any other matter referred to the Central Commission by the Government;*

4.3 Tariff Guidelines

Section 28 of the ERC Act, which is reproduced below, specifies the guidelines for tariff determination for the Commission. While these guidelines define the principles for tariff determination to be adopted by the Commission they are not mandatory. The Commission can depart from these guidelines though the reasons for doing would have to be recorded.

***28)** The Central Commission shall determine by regulations the terms conditions for fixation of tariff under clauses (a), (b) and (c) of section 13 and in doing so, shall be guided by the following, namely:-*

> ***a)** the generating companies and transmission utilities shall adopt such principles in order that they may earn an adequate return and at the same time that they do not exploit their dominant position in the generation, sale of electricity or in the inter-State transmission of electricity;*
> ***b)** the factors which would encourage efficiency, economical use of the resources, good performance, optimum investments and other matters which the Central Commission considers appropriate;*
> ***c)** national power plans formulated by the Central government; and*
> ***d)** such financial principles and their applications contained in Schedule VI of the Electricity Supply Act, 1948 as the Commission considers appropriate.*

4.4 Role in Tariff Setting

The Commission's primary role in tariff regulation is set out in Section 13 of the

ERC Act. Beyond this tariff setting role, the Commission is to aid and advise the Central Government in the formulation of tariff policy which must be fair to the consumers, while at the same time facilitating the mobilization of adequate resources for the power sector. This highlights the balancing role the Commission will have to play in resolving conflicts of interest, some of which could be as follows:

allowing an adequate return for electric utilities without unduly burdening the consumer,
ensuring that electric utilities do not exploit their dominant position while ensuring that investor interest is safeguarded,
encouraging the efficient and economic use of resources without being prescriptive on the solutions, thereby allowing free play for innovation,
promoting improved quality of supply and availability within the limits of least cost expansion in supply.
assisting in the formulation of environmental regulations without unduly burdening the utilities or the consumers.
ensuring the stability of the tariff regime with the need for dynamic improvements in the efficiency of supply and demand.

4.5 The process of Tariff Setting

4.5.1 As required under the ERC Act, CERC has issued its Conduct of Business Regulations, 1999 (CBR), which prescribes the procedure to be followed for tariff related petitions. Regulation 79 of the CBR is reproduced below:

No generating Company, owned or controlled by the Central government and no generating Company other than those owned or controlled by the Central Government, which has entered into or otherwise has a composite scheme[1] *for generation and sale of electricity in more than one State shall charge their customers any tariff for the supply of electricity without the prior approval of such tariff by the Commission.*

No generating or transmission utility shall charge any tariff for the inter-state transmission of energy without the prior approval of the Commission.

Provided that the above regulation regarding tariff for sale of energy shall apply to the generating companies owned or controlled by the Central Government with effect from the date of the above regulation will be notified for operation by the Commission.

Provided further that the existing tariff being charged by the generating companies owned or controlled by the Central Government shall continue to be charged after the date of the notification as referred to in the above regulation for such *period as may be specified in the notification.*

4.5.2 Chapter II of the CBR prescribes the requirements for the filing of petitions, including petitions for approval or revision of tariff. The Commission may also initiate the process of tariff revision. The Commission intends to issue detailed orders, shortly, specifying the terms and conditions, including the norms, which will be used by the Commission for tariff determination. These orders will also specify the information requirements to be met by the utilities on an annual basis as well as at the time of tariff determination or revision. While framing the norms, the Commission will carefully consider the responses received with regard to the issues highlighted in the Executive Summary.

4.6 Principles of Tariff Setting

Some of the factors which the Commission may apply, in the regulation of tariffs, have been specified in Regulation 82 of the CBR which is reproduced in **Annexure III.** The Commission is considering the following principles for inclusion in the proposed order on tariff principles and norms:

- Tariffs should be unambiguous and open to consistent interpretation.
- The tariff setting process should encourage the reduction of transaction cost and timely completion of proceedings.
- Tariffs should be determined in a transparent manner providing sufficient opportunity to all concerned.
- Tariffs should provide appropriate incentives for efficiency enhancement and the rational use of energy to suppliers and users.
- Tariffs should provide the correct pricing signals to investors for appropriate investment.
- The tariff should be stable and predictable over-time.
- The tariff regime should be flexible in its coverage of services and encourage market determination of prices where feasible.

4.7 Objectives of Tariff Setting

The Commission intends to use its powers with respect to tariff regulation to achieve a variety of objectives as listed below:

- Promote competition, efficiency and economy, including provision of incentives for operation at minimum costs.
- Match supply to demand within reasonable time while ensuring good quality of supply and reliable and secure system operation.
- Ensure optimisation of the generation mix.
- Explore the promotion of environmentally sound options.
- Facilitate efficient system operation including the economic transfer of energy across states and between regions.
- Ensure the settlement of commercial commitments, like timely payments, associated with energy supply and purchase.

[1] A composite scheme is defined as one which is built to supply power to any state other than the one in which the plant is located.

4.8 Options in Regulatory Methods

4.8.1 There are a variety of methods for tariff regulation as reviewed below. The choice of the method will be dictated by factors like effectiveness of the method in achieving tariff objectives, appropriateness, in the light of the existing methods being used for the purpose and administrative convenience given the existing infrastructure and information systems.

Rate of Return + Cost of Service;
Marginal Cost based Price;
Performance Based Regulation (PBR);
RPI-X;
Competitive Bidding;

4.8.2 Rate of Return Regulation[2] (RoR) / Cost of Service

4.8.2.1 The rate of return approach requires the determination of allowable costs, a rate base and the rate of return to be allowed on the rate base. The rate base is the capital amount on which a return is allowed. Typically the rate base represents the historic cost of the assets employed, less the accumulated depreciation of the asset[3]. The data requirements for carrying out RoR regulation are the historic costs of investments (in the Indian system the gross block) together with the variable costs incurred in the test year. The test year is generally taken as the latest financial year for which complete data is available.

4.8.2.2 This form of regulation has a number of distinct advantages:

a) It provides predictable, steady returns for the utility, which is conducive to making further investments.

b) The method is conceptually simple and unambiguous, generally making use of historic accounting data.

c) It is perceived to be fair. The cost of the electricity service is related directly to the actual asset base, with the end user paying for the facilities used. Today's user pays for the system built to date.

d) It is a traditional approach, used over many years, and is familiar to electric utilities, users and regulatory agencies.

4.8.2.3 The strengths of this form of regulation like its simplicity and predictability, also create its limitations.

a) Once an investment is made it tends to remain in the rate base and earns a return, even if the investment becomes non productive due to future developments, resulting in "stranded costs".

b) Since the rate of return and the rate base are the two main variables in the determination of the return to the utility. There is a tendency to over invest. Higher the investment, higher the rate base and hence the return to the investor.

c) The process is backward looking. The end user pays the historic cost and there are no price signals regarding future costs. This is not conducive to the efficient use of energy.

d) Historic book values may not provide sufficient revenue for future investments and may result in inadequate investment for future needs.

e) This is an intrusive form of regulation. It provides little incentive for the supplier to reduce costs and make efficiency gains. Since the net return to the utility is fixed any reduction in costs or increase in revenue are passed through to consumers.

f) Due to its intrusive nature the transaction costs are high The period of tariff review tends to be short. The nature of review is detailed as regulators have to overcome the inherent problem of information asymmetry between the regulated and the regulator

4.8.3 Performance Based Regulation (PBR)[4]

4.8.3.1 Recent trends have been towards more "light handed" regulation i.e. least interference by the regulators. PBR moves away from the RoR method by providing incentives for the utility to improve efficiency and reduce costs. Rather than prescribe a return, the utility is given a set of performance criteria to follow. Performance criteria[5] may include both operational and financial criteria. The return to the utility depends upon performance. Over achievement of the performance criteria can increase returns for the utility while underachievement will decrease returns. Performance targets are set using historic data, trends of system costs and operational characteristics. The establishment of an extensive data base for benchmarking performance criteria on the basis of industry best practice is an essential component for effective regulation under this method. A form of PBR is in actual use in India, where tariffs are based on normative parameters. With minor adaptation and reformulation of the normative values to

[2] This method has been used extensively in the US but there is a movement away as in California

[3] In some jurisdictions the rate of return is allowed on revalued assets. This tends to push up tariffs and is not widely used.

4 This method is being used in England and Wales and is being considered elsewhere, e.g. Ontario and Alberta, Canada

5 Performance criteria might include such items as, number of hours of system degradation (down time) losses expressed as a % of energy produced, expenditure on O&M, number of employees per 1000 consumers, lost time due to accidents, etc.

4.8.4 Hybrid and sliding scale methods in PBR

4.8.4.1 The hybrid method of PBR combines some of the best features of ROR and PBR. The hybrid approach combines elements of both the methods to suit local conditions. For some elements of tariff, performance bench marking could be applied, whereas with respect to other elements, the historic cost and rate of return may be applied. This would be effectively a refinement of the existing norm based ROR system.

4.8.4.2 This is a variation of the PBR method under which the performance criteria do not remain fixed but change over time. The purpose is to allow time to the utility to take the appropriate corrective steps before a tightening of the performance criteria.

4.8.5 RPI-X

This is the least intrusive form of regulation which has been extensively applied in the UK. It imposes a price cap which, over the tariff period, can be crossed only to the extent of the retail price inflation (RPI). This inflation rate is not fully available as an add-on to the price cap for the utility. It is reduced by a pre-determined efficiency gain (X). The strength of the scheme derives from the flexibility it affords to the utility to incur costs and take actions as is commercially feasible so long as the objectives of good quality supply are met within the capped price. The problem is how to retain this simplicity in design, while at the same time ensuring that an appropriate price (sufficient for financial viability without being generous), is allowed, for generating stations of different fuel types, ages, technology and siting. In transmission the issue would be to price transmission of energy irrespective of the age of the line, the capacity and technology. The ROR type of approach would try and establish a unique price for these classes of generators. The RPI minus X approach is more aggregative and prices services rather than technologies or fuel usage. It leaves these choices to the utility. Hence, under this system, old stations may lose on operational parameters but gain on total cost due to depreciated rate bases. For the application of this method the following critical decisions have to be taken by the regulator.

(a) How should the price cap be determined? Determination of the base year price can be complex since the regulator must decide to what extent current inefficiencies should be allowed. However the decision is no different than that required under a PBR regime while setting performance criteria.

(b) Which indices are to be used for inflation? In India, there are the wholesale price index (WPI), the consumer price indices (CPI) for agricultural labour, and the CPI for industrial workers. The latter has historically been higher than the former. Which of these is appropriate? There is also the problem of continuity and representativeness of the indices. If the basket of goods, measured for calculating the index changes, the continuity of application of the indices is lost. In the light of these factors would it be more appropriate to use a specially devised inflation formula rather than an existing index?

(c) Determination of the X factor, the proxy for efficiency improvements, is similarly complex. Time series data for the actual costs and efficiencies of a range of stations and transmission lines would be required to devise the X factor. Decisions would also be required on the sharing of efficiency gains between the utility and consumers.

4.8.6 Competitive Bidding

This is an alternative to tariff determination. Under the mega-project-policy, government has specified that this method would be followed for the determination of tariffs. This is a market based approach and hence avoids scrutiny of costs, revenues, etc. which is necessary in other methods of tariff determination. Successful adoption of this method presupposes the existence of competitive forces at the bidding stage.

4.8.7 Marginal Cost based Pricing Methods

4.8.7.1 From a theoretical perspective, marginal cost pricing methods provide the most appropriate signals for the pricing of electricity. Marginal pricing sends out a clear signal to the supplier and end user regarding the true value of the power being consumed. Marginal cost pricing emphasises future economic signals rather than relying on financial signals based on today's performance and historic financial costs. Long run Marginal Cost is the future cost of power which takes account of additional investments, consequent capacities, and projected variable costs. Short run Marginal Cost is the variable cost of incremental production. The data requirements for the determination of the LRMC are the energy production and capital costs of all future plants included in the long-term expansion plan. To determine the LRMC, the system expansion plan needs to be defined in terms of investment costs, variable costs and power and energy production. This is generally carried out with an investment horizon of 20 to 25 years.

4.8.7.2 The calculation of long run Marginal Cost Pricing is a necessary tool for estimating the efficiency of current tariffs. If the current price being paid to suppliers is lower than the LRMC, then a careful evaluation of the revenues being earned by them is necessary, to ensure that the utilities are being left with sufficient investible resources. Conversely, if the LRMC is less than the current prices paid to suppliers they are probably being over compensated. Short-run Marginal Cost captures only the operating cost and ignores fixed cost which are 'sunk' and cannot be changed in the short-term. Hence it provides appropriate signals to system operators for the despatch of energy and to users for the use of energy. The rational user will always ensure that the incremental value added or the incremental "utility" of the use of energy is higher than the short run marginal cost of energy.

4.8.7.3 While providing a good theoretical basis for the determination of tariffs, there are a number of disadvantages[7] to the marginal costing approach, most of the disadvantages relate to the practicality of the method. A number of assumptions used in the least cost expansion plan may be controversial and contestable. Some examples are uncertainties inherent in the energy and demand forecasts, system planning assumptions, unit costs used to establish the investment plan, size of the system or the discount rate. Marginal cost based tariff may be difficult to reconcile with the actual costs encountered in the system. The method uses economic, rather than financial concepts and so may overstate or understate financial requirements. In periods of falling capital costs the LRMC will decrease which may become lower than the costs required to recoup historic costs. Similarly in periods of escalating costs LRMC will tend to overstate the price required to recoup historic costs.

[7] This does not apply where the marginal price is determined through a bidding system, such as in the power pool in UK.

4.9. Issues in Tariff Setting

There are a variety of issues regarding tariff setting on which the Commission would like to get the responses of all concerned. Some of these issues are listed below :

4.9.1 Rate of Return and Risk

4.9.1.1 The return to a utility, expressed in monetary terms, is calculated using two variables. The Rate of Return which is a proportion or percentage and the Rate Base which is also expressed in monetary terms.

The rate of return, approved for a utility, consists of two principal components. A risk free[8] cost of capital and an element representing adequate compensation for taking on the perceived risk associated with the investment. Broadly two alternative formulations may be followed. Either the utility may be approved a Return on Equity (ROE) or a Return on Capital Employed (ROCE). In India, the ROE is set at 16%[9] for all investments, regardless of actual cost of capital or associated risk, the rate itself, which includes a risk component, and

The ROE or ROCE is applied to a rate base to determine the return of the utility. Where ROE is used it will be applied to the funds of the owners or shareholders equity. In such cases interest cost on outstanding debt is a pass through. Alternatively, if a Return on Capital Employed (ROCE) is being used, the rate base will be the capital base, which represents prudent investments made by the promoter on which the return is calculated and provided in the tariff. The capital base consists of both debt and equity. A strength of this method for allowing return is the flexibility it allows to the utility to optimise financial costs by varying the debt equity ratio inline with market trends.

4.9.1.2 There can be several determinants and classifications of risk. Some are listed below.

country, political, regulatory risk, financial, cost overrun, foreign exchange, interest rate risk, project size and type (Hydro power versus thermal, transmission), pre or post construction, fuel supply and price risk.

Risk may vary also with the nature of ownership; public vs. private, foreign vs. local.

4.9.1.3 Of the two components of rate of return the risk free cost of capital is constant for all investments. However the risk premium will vary for different categories of investments. This implies that the appropriate rate of return will vary with the characteristics of the investment. Should not such variations be reflected in the rate of return allowed by the Commission?

4.9.2. Information requirements

The determination of allowable costs and the rate base require significant amounts of information to be filed by the utility. The various elements of costs are already discussed in Annexure II. Costs can be collected at the time of the tariff submission or annually, based on the audited financial statements of the utility. The Commission intends to prescribe both annual filings as well as those, specific to tariff petitions. The intention is to develop a database over time for assessing the performance of individual plants. This type of date is required for implementing any performance based regulatory regime

4.9.3 Tariff Entity

Tariffs can be determined at different levels of disaggregation. The choice can vary between a unit, station, region or company in generation, and at line, region or company in transmission, are issues to be addressed. The decision depends on the availability of data to support such unbundling and the anticipated efficiency improvements.

4.9.4 Treatment of Partially Completed / Commissioned Stations

How should common costs be allocated? At what stage and on what basis should they be allowed to be recovered through tariff. Infrastructure projects have significant levels of common costs. Since projects are implemented in modules or stages, a common cost like a gas import terminal may be incurred in a lump sum, because of the economies of scale, even though the generation capacity may be added in stages. Hence till the full generation capacity is added, only a part of the common facility may be in beneficial use. Currently the extent of common cost allowed is not linked, to the proportion of final output or capacity of the station or transmission line, actually made commercially available. Can alternative allocation methods avoid unnecessary lags between the creation of common assets and their beneficial use?

4.9.5 Periodicity of Tariff Setting

The period between tariff revisions could vary from one to five years. Currently tariffs are effective for five years, once the tariff has been established and the construction of a station[10] is complete. The argument in favour of frequent reviews is that tariffs can be adjusted regularly and the rate of return to the utility controlled. However this removes any incentive for the utility to make efficiency improvements. Under a PBR system the utility must be allowed a sufficiently long period over which the tariff will remain effective. This enables it to make efficiency improvements and capture the efficiency before the review is required. Shortening the period between tariff review also adds costs to the tariff setting process and increases the burden of regulation. What is the appropriate period between tariff reviews in the Indian context?

4.9.6 Dealing with Change between Tariff Filing Periods

In between normal tariff review periods, additional adjustments may be required. How should these be dealt with? What should be the scope for automatic adjustment? Clearly the method of adjustment will vary with the method of regulation. Under an ROR system all changes have to be considered and approved specifically. Under RPI minus X adjustments are built into the formula. Under competitive bidding the formulas are prescribed in the contract. Can the area of certainty regarding the pass through of unavoidable costs be enlarged for the supplier? How can the consumer be simultaneously assured that only reasonable cost escalations will be passed through? How can costly and time-consuming proceedings be avoided? Where a consumer wishes to challenge the cost escalations passed through by the utility, should it be necessary for the consumer to pay under protest, before it is taken up for consideration by the Commission?

4.9.7 Retrospective Adjustment of Tariffs

Retrospective adjustments arise on various counts including delays in finalisation of project cost, which is approved post-construction for public sector projects. This approach is unusual in the sense that costs may be added to a project after its original approval. Consideration may be given as to whether this method should be continued. This is in contrast to IPP projects, where costs are contractually decided in advance. Post commissioning adjustments in tariff are not in the best interest of the buyer as it may insulate the supplier from the risks associated with plant construction. A clear definition of what may be reviewed retrospectively is required. The concept of allocation of risk needs to be considered. Should the buyer be responsible for all unforeseeable risk, or should the risk be shared between buyer and seller? A principle that might be adopted is that tariffs, once set, remain in place for that transaction. This implies that retrospective revision of bills would not be allowed other than for accounting errors. Any approved adjustment in tariff due to new investments could then be applied only to future years.

[8] The risk free interest rate is usually taken as the rate payable on long term government bonds.

[9] The 16% return on equity is allowed on achieving 68.5% availability / deemed PLF for Thermal generation, 85% availability for Hydro Stations and 90% availability in transmission. In the case of central Thermal Stations in existence prior to 1992 the 16% return on equity is allowed on a notional equity of 50% of the capital cost. Generators who achieve higher than targeted availability can earn higher returns.

[10] A station constructed in stages with considerable time lapse between stages or with stages employing different technology may be regarded as two separate stations in terms of tariff filing

4.9.8 Efficiency of Operational and Cost Norms

Under a regulated tariff regime, how can a regulator ensure that the norms being used for judging performance and thus allowing incentives or imposing disincentives, are challenging, without being burdensome for the utility? How should incentives be set, so that they induce continuous improvements in the efficiency of supply and demand?

4.9.9 Treatment of Depreciation and Asset Life

The depreciation rates currently in use are relatively high. Considering accepted asset life, the depreciation rates in use in India have the effect of front loading the tariff. Typical asset lives used internationally[11] are:

Hydro power unit 30-40 years
Thermal (coal) unit 25-30 years
Transmission lines 25-35 years

This would indicate that depreciation rates in the range 3-4% would be appropriate based on straight line depreciation, versus the 7-8% now used in India. Adoption of more realistic asset lives, linked to the corresponding depreciation rates, would have a downward effect on tariffs. Adoption of more realistic asset lives might also provide pressure to maintain assets in a better condition to achieve such asset life. It may be useful, to review actual asset life of various types of plant in India, as opposed to the notional asset life indicated by the depreciation rates. If asset life in India is actually lower than the international norms, this indicates that the asset replacement is taking place far more frequently than the norms of good utility practice would allow.

4.9.10 Allocation of Common Overheads

Correct allocation of and accounting for overheads and common services is required to ensure that there are no cross subsidies between stations or between plants, of different vintages and technologies. Similar concerns apply to cross regional allocation of overheads for the transmission network. The Commission proposes to address this issue, by calling for detailed operational data in the annual filing, and using this data for estimating cross subsidies of this nature.

4.9.11 Treatment of Taxes

The current practice is to allow rates of return on a post-tax basis. This leads to retroactive adjustment to the tariff to provide the prescribed rate of return. The Commission will consider the possibility of establishing a pre-tax rate of return. which would eliminate this need for adjustment. Such an approach would also be consistent with the treatment of other corporate entities in India.

4.9.12 Linkages between Tariff and Payments

A very significant problem today is delayed or non-payment by state level utilities against energy supplied by generators. While the unremunerative retail tariff structure may be one of the causes, this cost cannot be passed backwards to the generators or the transmission utilities. With the changes taking place at the State level, including the introduction of State level regulation, the Commission expects that along with the rationalisation of retail tariff, additional pressure will be brought to bear on the SEBs to pay on time for the power purchased by them. This is necessary to reduce the overall perceptions of risk and hence, the cost of capital and increase the volume of capital supply, for the power sector. The Commission intends to adopt a comprehensive view of its powers to regulate tariff, so as to include, the entire cycle of commercial transactions. The transaction of selling and consuming electric power should be seen as completed only when the power is generated, transmitted, consumed and paid for. This issue must be addressed.

4.9.13 Adoption of multiple Tariff Setting Methodologies

The Commission does not intend to be rigid in its choice of regulation method. It intends to use tariff setting methodologies in the context of their workability and appropriateness. It is possible that different methodologies may be adopted for separate sets of services or segments of the industry. As has been stated earlier the Mega Power Policy of the central government prescribes competitive bidding for the sale price of bulk power. In one proposal for a mega generation station in the private sector, which predates the policy, a negotiated approach has been adopted by the central government. The tariff of private transmission licensees may also be decided using the competitive bidding approach. The tariff of Central Stations and POWERGRID may however continue to be regulated using the RoR, its variants or the RPI minus X methodology. Clearly, the adoption of multiple methodologies raises issues concerning the consistency of principles and their applications, across all methodology. The Commission will endeavor to assure a level playing field, consistency in the applications of basic principles of tariff determination and a non distortionary tariff regime, which maximises efficiency and pays due regard to the interest of the consumer.

4.10 Conclusion

The provisions of the ERC Act provide sufficient flexibility to the Commission to determine the nature and type of tariff regulation to be followed. The endeavor of the Commission is to use the process of tariff setting to achieve the goals of competition, efficiency and economy. The Commission is conscious, however, of the need for stability and predictability, in the tariff regime. Ensuring the financial viability of efficient and proactive utilities, will be a prime concern. At the same time safeguarding the interests of the consumers becomes a major responsibility of the Commission, particularly, when the market structure and system conditions do not support competition. The Commission is to play a balancing role. It intends to discharge this responsibility, transparently, through a consultative mode. It expects that participative decision making will lighten the burden of transiting, to a more efficient system, for all stakeholders.

[11] The quoted figures provide the range of values for utilities in the USA and Canada.

CHAPTER 5

5. GENERATION TARIFFS

5.1 Introduction

International experience in restructuring of the electric power industry indicates that generation is the first segment of the industry, which is opened to competition. In India also, the liberalisation of the power sector was commenced by introducing private sector competition into generation. The Mega Power Policy of the Central Government has already opened the area of tariff setting for such project to market forces by opting for the competitive bidding route. However progress beyond entry point competition is restrained by the overall deficit in supply and the need to step up investments. Private sector investors and debt providers have so far insisted on transferring market risk to the consumers as a precondition for investment inflow. Generation stations have long term contracts which insulate them from all market risk, defined as the possibility that they may not be able to sell their production. Long term contracts restrain competition. Hence the tariff design has to simulate the beneficial impacts of competition to extract efficiency improvements. This chapter defines the regulated entities, reviews the primary objectives of the Commission while setting thermal and hydro generation tariffs and identifies options for tariff setting. These objectives, strategies and issues are specific to generation tariffs. The more general issues have already been separately discussed in Chapter 4. The reader would be advised to keep these general issues in mind while perusing this chapter.

5.2 Regulated entities in generation

NTPC, NLC, NEEPCO and NHPC are the primary entities in the central public sector, which are under the regulatory jurisdiction of the Commission. There are several other power utilities in the central public sector, which are not incorporated under the Companies Act and hence are not currently, under the jurisdiction of the Commission. Any other generators, which may be established in future, under a composite scheme, for the generation and supply of energy, in more than one state, will also be under the regulatory jurisdiction of the Commission. However there no such projects are under construction though the central government is considering some proposals.

5. 3 Objectives of Tariff Setting

5.3.1 NTPC commands the largest share of generation within the capacity under the regulatory jurisdiction of the Commission. NTPC is a progressive company with strong fundamentals. However, its financial credibility faces threats on account of the accumulating burden of current assets due to bills remaining unpaid by SEBs or their successor entities. The SEBs on the other hand complain that much of the outstandings are on account of over generation by NTPC and other bills under dispute. The Commission is committed to resolving the situation.

5.3.2 The Commission is concerned that the long time gap, since the operational norms were notified in 1990, has resulted in their no longer being challenging. While, over the last ten years, they have been responsible for considerable improvements in efficiency they now need to be revised. Such revision will reduce the burden on SEBs, and their successors, by lowering the tariff for bulk power.

5.3.3 The Commission is concerned about the falling share of hydro power in the generation profile. It intends to ensure a tariff which induces incremental investment in hydro while preserving its status in the merit order, as a must run technology.

5.3.4 Currently generators bear the cost of providing reactive power even though the corrective steps for reducing reactive load are not within their control. Generation of reactive power, at the cost of real power, is an avoidable efficiency loss. The cost of meeting reactive power demand must be transferred to consumers

5.3.5 The Commission would like to implement competition in bulk supply and allow market determination of the price for such supply.

5.4 Tariff Setting Strategy

5.4.1 Unbundling of Generation Tariffs

The Commission has already heard the petition and the responses filed in Petition No.2/1999 regarding the Availability Based Tariff (ABT) proposed by the Central Government. This proposal intends to implement a two-part generation tariff which unbundles the availability charge from the energy charge. This availability charge will be payable by all those SEBs, who have either contracted for capacity creation with the generator, or to whom capacity has been allocated under the Gadgil formula. The availability charge will comprise of all fixed costs, which have been prudently incurred by the generator as a consequence of installing capacity. Its recovery will be linked to a target availability. Underachievement will result in under recovery of the fixed costs while over achievement will result in an incentive over and above recovery of fixed costs. The availability target will be set at challenging levels.

5.4.2 Redefinition of operational norms

The Commission would like to introduce a tariff regime, which ensures a continuous improvement, in the efficiency with which energy is supplied. It feels this can best be done by a regime which rewards performance through incentives. Towards this end, it will introduce, either a PBR regime or a regime based on RPI minus X. In determining the operational norms it is considering the use of the operational norms finalised by the CEA in 1997. These are expected to reduce the cost of bulk energy supply.

5.4.3 Incentives for hydropower

The uncertainties of hydropower development have deterred the private sector so far from investing in this energy resource. The public sector projects on the other hand do not, in practice, have a hard budget constraint. This is one reason why public sector entities have found it easier to develop this resource. A cost effective way to compensate developers for the uncertainty of hydro power development will need to be formulated.

5.4.4 Reactive energy charge

Reactive energy supplied by generators at the cost of real power could be charged to the SEBs as a separate charge.

5.4.5 Introduction of competition and power markets

A competitive market for generation requires some surplus capacity in generation and transmission. This does not appear feasible in the short run. However, the possibility of introducing partial competition can be explored on a regional basis.

5.4.5.1 One alternative, is to introduce competition during off peak periods. The appropriate definition of peak and off peak periods will be a precondition Presently, REBs notify peak and off-peak periods. Appreciating the considerable scope for regional variations, the methodology for such identification would need detailed examination. The experience with IPPs so far indicates that incremental investments in generation are dependent on the assured payment of fixed cost linked to availability targets. The problem is that assured payments of fixed costs reduce incentives for progressive cost reductions by generators. In fact, if the full fixed costs and return on the rate base are recoverable on the basis of availability and the energy charge only reflects actual variable costs, the generator has no particular incentive to be despatched. He only has an incentive to be available. The purpose of proposing competition at off peak is to incentivise the progressive reduction of variable costs and to allow actual variable costs to be revealed. The possible outline is given below:

a) Unlike current practise, separate availability targets will be fixed for peak and off-peak periods. Unlike today there will be no incentive for overachieving target availability. The recovery of fixed charge will be linked to the achievement of these availability levels. Non achievement of target availability levels will result in a reduction in the recovery of fixed charge at accelerating rates of penalty.

b) The opportunity for earning a surplus higher than the allowed return will lie only in getting despatched. During peak times, the generator will earn a regulated energy charge for energy despatched. Very efficient generators will have the opportunity to earn an additional surplus (over and above availability linked return) by reducing their actual variable costs below the regulated energy charge. During off peak, the market will equilibrate demand and supply at a certain price. All generators, with actual variable costs below this price, will have the opportunity to earn additional return (over and above the availability linked return) by supplying energy at off peak. Generators who cannot be despatched during off peak will not earn any incentive above the availability target linked return.

c) During off peak, a cap will be imposed on the market price for energy, which will be the same as the regulated energy charge. This will guard against the possibility of sharp peaks in

energy prices, due to short term shortages in supply.
d) The Commission is currently considering the proposal for Frequency linked Charge for Unscheduled Interchange (FLCUI), which has been proposed by the Central Government and is supported by the CTU as a measure to introduce grid discipline. This proposal can be meshed with this proposal for introducing competition at off-peak, since it relates only to unscheduled interchanges of energy while the proposed scheme for competition relates only to scheduled interchanges of energy.

5.4.5.2 What will this proposal achieve? The proposal for an off peak competitive market will establish a rudimentary market for power which does not exist today. It will encourage SEBs and their successors to contract directly with generators. It will allow the market to establish a market price for power differentiated by customer. An SEB with a poor payment record may be charged higher by the generator (within the price cap) than an SEB with a good payment record. It will allow SEBs and generators to vary the risk return by varying the ration of long term supply contracts and spot purchases. It will induce SEBs to consider managing load more effectively since the costs of not doing so will be attributable directly to them. An agency will need to be identified, which will act as the power exchange. recording contracts, recording sales, raising bills and ensuring settlement. In the initial stages. the Regional Electricity Boards are the best equipped to perform this task.

5.5 Issues in Generation Tariff

The proposals for redesign of generation tariffs, listed above. are the tentative feelings of the Commission. They have to be supported by analysis and exposed to debate. Towards this end the following issues are identified on which the Commission would like responses from stakeholders :

5.5.1 While making SEBs responsible for the shares allocated to them. who should be responsible for the unallocated share of the generator which is reserved for the Central Government? One option is that it should be payable by the Central Government. If the Central Government allocates this to an SEB it will become payable by that SEB. Where the SEB defaults on such payment, it will be the contingent liability of the Central Government. Another option could be to transfer this share to the generator, who could contract it out on a commercial basis. The third option is to contract it out for use as reserve capacity, where feasible and recover the costs as a part of the RLDC charge.

5.5.2 The CEA proposal for redefinition of operational norms formulated in 1997 has adopted the intrusive ROR approach. Is this an efficient way of defining norms where capital investments, technology and fuel choices and location are taken as given and factored in while determining the norms? Would it be possible to define norms more broadly so that even the areas of technology and fuel choice and location become risks transferred to the supplier, rather than the consumer?

5.5.3 How feasible is this scheme for partial competition? The scheme is workable and can show results through a reduction in sale price in any region where there is an energy surplus during off peak. Where there is no surplus the scheme can still be implemented. The price cap will restrain any undue exploitation of shortage conditions by the suppliers while even short term surpluses will induce generators to compete to supply at prices lower than the capped price. Are there any other barriers to its implementation?

5.6 Conclusion

There is considerable scope for reduction in generation tariffs. Such reduction need not impact the profitability of generators if adequate steps are taken by them for efficiency enhancement. The Commission will assist this process by redesigning tariffs, allocating costs to charges, which are differentiated on the basis of availability, active and reactive energy supply. There is also the possibility of introducing a limited level of competition inGeneration, during off peak, when energy supply may be in surplus. This is a significant advance over the existing system, where competition is only visible at the entry point. While the extent and volume of energy, sold under competitive conditions, during off peak, may be limited, the spill over benefits of establishing a long term or spot market, for the trading of energy, are expected to be considerable. It can reorient the entire system of power purchase in the SEBs and their successors, and result in the emergence of a market for financial derivatives in power sale and purchase. The efficiencies achieved in bulk power tariffs will have to be replicated in retail supply if the final consumer is to benefit. State level regulators will have to achieve this objective. At the central level, the primary challenge is to incentivise generators to reduce costs, without impacting the financial viability of responsive generators. Simultaneously a market will be established for trade in power. This will be the precursor to the establishment of full competition in generation in the medium term.

CHAPTER 6

6. TRANSMISSION TARIFFS

6.1 Introduction

Inter state transmission costs on average, account for less than 2% of the cost of power delivered at the retail end. Transmission tariffs are important therefore, not because of their cost impact on the delivered cost of power but because of the signals they provide for incremental investment, maintenance of current assets and efficient management of the transmission system. Adequate transmission capacity is necessary for trading in power and for the transfer of power with the objective of cost optimisation. This chapter reviews the regulated entities, primary objectives of the Commission while setting transmission tariffs, the strategies it intends to follow and some of the important issues in tariff design. Some general issues concerning tariff have already been discussed in Chapter 4. The reader is advised to keep these in mind also.

6.2 Regulated Entities and Services

The transmission tariffs of POWERGRID and any other transmission licensee operating in the inter state transmission system are to be determined by the Commission. In addition the transmission tariff for all interstate transmission is within the regulatory jurisdiction of the Commission. The Commission has also to determine the charges to be paid to the RLDC by the constituents of regional grids. As of today there are no transmission licensees. In Petition No 1/1999 relating to the Indian Electricity Grid Code, POWERGRID has been entrusted the task of proposing the principle and procedures to be followed for the grant of licenses to transmission entities.

6.3 Objectives of Tariff Setting in Transmission

The transmission system in India, faces challenges, similar to those in generation. The principal challenge is of fixing accountability for costs incurred in investments and improvements in operational efficiency. The Commission therefore, intends to achieve the following objectives through its tariff regime.

(a) Ensure the productivity of existing and future investments.

(b) Ensure adoption of the least cost approach to incremental investments.

(c) Provide international quality transmission services.

(d) Maintain the security of the regional grids.

(e) Adoption of efficient procedures for scheduling and despatch.

(f) Promote the development of a national grid

6.4 Unbundling of Transmission Costs and Services

6.4.1 Currently, the costs of the services provided by POWERGRID are added together (bundled) and charged to the SEBs / STUs in proportion to their energy drawls from the inter-state grid. Details of the various services provided in transmission, data required for the calculation of separate charges for these services and the parties involved in these transactions are given in **Annexure IV.** Clearly, the costs for providing different services should be unbundled to provide better price signals to those who are using these services and to ensure that one service is not cross subsidising the other. Transmission services can be unbundled by classifying them in terms of the nature of cost incurred in their provision. Unlike generation, the share of fixed costs is much higher in the total cost of transmission.

6.4.2 Services which impose a fixed cost on the system

The services, which impose a fixed cost on the system, are the following:

(a) Provision of transmission facility, including reserve.

(b) Provision of adequate reactive power support and voltage control

(c) Investment planning

(d) Reinforcement costs, or the cost of providing additional capacity for accommodating an additional transaction.

(e) Costs incurred in the RLDC for operation and maintenance of the regional grid.

The transmission service provider makes available all these services, irrespective of whether the flow takes place or not. These are the sunk costs of the transmission and system control agency.

6.4.3 Services which impose a variable cost on the system

The following components of variable cost, in the transmission system, can be isolated, though the most significant cost is on account of transmission loss.

(a) Transmission loss

(b) Billing and collection costs

(c) Analysis, arrangements of transactions and the incremental operational costs of matching demand with supply on a real time basis. This may comprise variations in the transmission loss and the congestion costs imposed on users due to accommodating incremental transmission.

Currently, transmission losses are not charged as part of transmission cost. They are included in the tariffs payable by the SEB or its successor to the CGS. The other costs are rolled into the single part transmission charge.

6.5 Types of Transmission Contracts

The existing system does not distinguish between the nature of demand of the user. A single agreement allows a user to connect to the grid and draw energy as and when required. There is no requirement for the payment of a connection charge, or the need for contracting for a minimum level of load. If the user does not draw energy he does not pay. The structure of demand however is more complex. Energy transactions can be classified as below into the nature of demand imposed by them.

a) Firm Power is the power that may be interrupted only for system emergencies. Such services may be provided either on long-term or short-term contracts. Typically, user should pay for the capacity, which is reserved for his use.
b) Non-Firm Power services permit the transmission service provider to interrupt services at any time. The commitment of the service provider is lower. Hence they do not need reserve transmission capacity to service load at all times. Such services could be sub classified as:

1) Curtailable Services that provide for interruption for specified conditions only and hence provide more surety of supply to the user.
2) As Available Power transfers which are agreed in real-time operation during the course of the day.

Annexure V classifies these transactions and suggests the possible allocation of various components to each type of transaction. Broadly firm services require the payment of the fixed costs related to the system while non-firm services would require only the payment of the variable charge.

6.6 Strategies in Tariff Setting for Transmission

The rationale for a single part average regional tariff has been that it is not cost effective or technically possible to segregate the various cost elements. Unbundling tariffs will require system load studies on a dynamic basis to identify the nature and direction of flows to various constituents of the system. However, a rudimentary form of unbundling can not only allocate costs better but also result in efficient outcomes. The following are some such initiatives.

6.6.1 In an integrated grid system it may not always be cost effective to attempt such segregation in some cases. Wherever specific users of a segment of the grid system cannot be identified there is no alternative to using a pooled price for the use of such assets. However the pooled price can be segregated into fixed and variable costs. All users of the grid who have contracted for firm transaction capacity should pay a connection charge which should comprise of the following.

a) The costs incurred in the RLDC for scheduling, despatch and accounting for power flows proportionate to the allocated/contracted load of the constituent.
b) A share in the pooled regional fixed costs on the basis of allocated/contracted load.
c) The costs attributed to metering and billing the constituent.

The connection charge, payable on the basis of connected load to POWERGRID by users (other than generators), could be linked to target availability, fixed at a sufficiently high level which will have to be assured by POWEPGRID. Availability below the target could be penalised through under recovery of the fixed cost. In addition users will pay a variable charge calculated by pooling the regional variable costs.

6.6.2 Holders of non firm power transfer contracts may be required to pay only a part of the connection charge relating to the costs incurred in metering and billing and not the other components of fixed charge. They may be exempted from these costs because these costs were not incurred to service their load. They are serviced by the utility only when surplus capacity is available and hence should not be asked to share in the fixed cost. In addition to the connection charge, such users could pay an average variable charge calculated by pooling the regional variable cost. Since the transmission utility will need to be incentivised to service such non-firm transactions some incentive will have to be built into the variable charge

6.6.3 In the case of all assets where the costs are attributable to specific users the intended beneficiaries should pay the fixed costs. Typically, such beneficiaries would have contracts for the supply of firm capacity. Evacuation lines, which link generating stations to the grid, or other lines, which transfer power between identifiable entities, are some examples. In such cases the beneficiaries would pay the specific tariff for that line. This tariff could be a two-part tariff. The fixed cost would be recoverable through the fixed charge, at a target level of availability. The variable cost, comprising primarily transmission loss, on the basis of norms, and any other variable charge could be recoverable through a charge linked to energy transfer.

6.7 Issues in Transmission Pricing

The Commission seeks consultations on the following issues. Some of these are philosophical in that they relate to the directions in tariff design in the medium term. However many others are of immediate relevance and relate to putting in place an efficient tariff regime immediately.

6.7.1 What is the appropriate methodology of tariff setting for transmission? Should the existing ROR methodology be continued? Can the PBR elements be incorporated on a larger scale? Would the adoption of the RPI minus X approach yield additional dividends?

6.7.2 The "Postage stamp" method of averaging regional costs does not acknowledge the route or distance involved in the power wheeling or the type of facilities involved in the power wheeling. All the users assume a portion of the cost of a transmission transaction, even when they are neither party to that transaction nor responsible for the costs related to the wheeling of power associated to this transaction. How can the extent of usage of an integrated system be reflected in the tariff regime?

6.7.3 Where a transmission transaction takes place, it removes the opportunity of that transmission capacity being used by someone else. This lost opportunity could be valued in terms of the foregone revenue and the incremental costs if any imposed by a transaction. This calculated value would represent the true cost of the transaction. How can such costs be reflected in the tariff regime?

6.7.4 Where excess transmission capacity has been built, as in the case of North-East, how should the costs be allocated to tariff?

6.7.5 How should the RLDC charge be calculated? Should the cost of capital allowed for the RLDCs be the same as the cost of capital for transmission? What is the nature of incentives, which can be built into the charge to ensure the efficient operation of the RLDCs?

6.7.6 POWERGRID is likely to use the transmission set up to provide telecom services. What is the methodology to be adopted for segregating the capital costs and the operating costs of these two activities? Ring fencing is imperative for transparency. If access to transmission towers and rights of way are leased to a telecom subsidiary of POWERGRID, which principles of transfer pricing are to be followed?

6.8 Conclusion

The relatively low incidence of transmission tariff has traditionally resulted in the application of the simple methods for tariff design. However in the simplicity of design the power of tariff design to efficiently allocate capital andresources also gets diluted. The transmission sector is fairly efficient and well managed However significant improvements are required in system control scheduling and despatch. While most of the solutions lie in more disciplined use of the grid there are possibilities for the inclusion of price based incentives to ensure such grid discipline. The Commission is already considering the proposal for implementation of the frequency-based charge for unscheduled interchange. This proposes to reward users of the grid who maintain discipline in their drawls of energy and penalise those who do not. The need for rapid expansions of the inter-state grid requires the allocation of the costs of such expansion to appropriate users so that expansions are cost efficient and only occur where there is demand. Simultaneously, there is the need to integrate private licensees into the existing interstate system. Tariff determination in their case could possibly be done, using the competitive bidding route. In general, there is a need to segregate the fixed costs of the system, which should only be borne by those users who have contracted for firm capacity, variable costs, which should be allocated to the tariff to be charged on all users proportional to the energy or load imposed and the costs of system control, scheduling and despatch, which should be allocated to all users of the inter state grid. More advanced techniques, incorporating the cost of congestion on particular lines, would require greater degrees of sophistication in monitoring load flows and may only be possible in the medium term after the system has stabilised.

Annex I

FINANCIAL PRINCIPLES AND THEIR APPLICATION FOR LICENSEES AS CONTAINED IN THE SIXTH SCHEDULE OF E (S) ACT, 1948.

The broad principles contained in Schedule - VI are as follows:

1. The licensee shall so adjust his charges for the sale of electricity whether by enhancing or reducing them that his clear profit in any year of account shall not, as far as possible, exceed the amount of reasonable return.

2. "Reasonable return" in respect of any year of account is the sum of the amount found by applying the standard rate to the capital base (net of any contributions made by consumers for cost of construction) at the end of that year and certain other permissible earnings as spelt out in clause XVII(a) of that Schedule.

3. Standard rate in respect of any year means:

a) In relation to that part of the capital base for that year of account which is equivalent to the capital base as on the 31st day of March, 1965, seven per centum per annum.

b) In relation to the remaining capital base for that year, the Reserve Bank Rate ruling at the beginning of that year plus

i) two percentum for investments made upto the 15th day of October, 1991

ii) five percentum for investments made on and from 16th day of October, 1991 till the 31st day of March, 1999 and

iii) differential between sixteen percentum and Reserve Bank Rate ruling at the beginning of that year for investments made thereafter.

4. "Capital base" means the sum of

a) the original cost of fixed assets available for use;
b) the cost of intangible assets;
c) the original cost of works in progress;
d) the amount of investment compulsorily made under paragraph IV of Schedule-VI; and
e) an amount on account of working capital;

Less -

a) the amount written off or set aside on account of depreciation;
b) the amount of any loan advanced by the Board
c) the amount of any loans borrowed from organisations approved by the State Government;
d) the amount of any debentures issued by the licensee;
e) the amount deposited in cash with the licensee by consumers by way of security;
f) the amount standing to the credit of the Tariffs and Dividends Control Reserve;
g) the amount standing to the credit of the Development Reserve, and
h) the amount carried forward in the accounts of the licensee for distribution to the consumers

5. "Clear Profit" means the difference between the amount of income and the sum of expenditure plus specific appropriations. Income referred above is the income derived from -

a) gross receipts from sale of energy less discount;
b) rental of meters;
c) rents;
d) transfer fees
e) investments and other general receipts.

Expenditure relates to -

(a) generation and purchase of energy;
(b) distribution and sale of energy;
(c) rents;
(d) interest on loans/debentures/security deposits;
(e) legal charges;
(f) bad debts;
(g) auditors' fees
(h) management expenditure;
(i) depreciation
(j) other expenses;
(k) contributions to provident fund;
(l) bonus paid to employees etc.

Special appropriations cover -

(a) previous losses
(b) all taxes on income and profits;

(c) instalments of written down amounts in respect of intangible assets and new capital issue assets,
(d) contributions to the Contingency Reserve,
(e) contributions towards arrears of depreciation
(f) contributions to the Development Reserve and
(g) debt redemption obligation of the private licensees which may be done on a year to year basis, taking into account the requirements of debt redemption and resource generation through depreciation, retained surplus;
(h) Other special appropriations permitted by the State Government.

6. If the clear profit of licensee in any year of account is in excess of the amount of reasonable return, one third of such excess, not exceeding five percent of the amount of reasonable return shall be at the disposal of the undertaking. Of the balance of the excess, one half shall be appropriated to Tariff and Dividends Control Reserve and the remaining half shall be distributed in the form of a proportional rebate on the amounts collected from the sale of electricity and meter rentals or carried forward in the accounts of the licensee for distribution to the consumers in future, in such manner as the State Government may direct.
7. The licensee shall create from existing reserves or from the revenues of the undertaking a reserve to be called Contingencies Reserve and maintain it according to the stipulations contained in Schedule-VI.
8. The licensee shall also create a reserve to be called the Development Reserve to which shall be appropriated in respect of each accounting year a sum equal to the amount of income-tax and super-tax as stipulated in Schedule-VI.
9. The licensee shall provide each year for depreciation such sum calculated in accordance with such principles as the Central Government may notify in the Official Gazette, from time to time.
These broad principles and other details stipulated in Schedule-VI of E(S) Act, 1948 constitute the financial principles applicable to licensees for tariff determination.

Annex II

K.P. RAO COMMITTEE REPORT--- A BRIEF ANALYSIS
Tariff for Central Thermal Generating Stations

1. Introduction of the concept of two-part tariff, i.e. a fixed and a variable charge;
2. Payment of fixed charges on normative basis recovered at normative PLF: return on notional equity of 50% of gross capital cost at government notified rates, Interest at actual weighted average interest rate on notional outstanding debt (50% of gross capital cost reduced by actual cumulative repayment), 2.5% of Current Capital Cost as O&M; Interest at an average cash credit rate on a normative level of working capital.

> ***The fixed expenses calculated in the above manner for each year covered by the tariff period of 5 years are aggregated and average annual tariffs arrived at. These are payable collectively by the SEBs on a monthly basis at 1/12th of the annual fixed expenses.***
>
> Elements of fixed charges are further elaborated in Table 1. Details of incentives and disincentives are indicated in Table 2.

3. The calculation of variable charges was based on normative parameters for

Station Heat Rate, Auxiliary Consumption and Specific Secondary Fuel Oil which were different for different technologies; The variable charge consists of only fuel costs

a) Cost of primary fuel like coal, oil or gas;
b) Cost of secondary fuel oil.

Auxiliary Electricity Consumption indirectly affects the fuel cost recovery and hence was also prescribed. Norms & Elements of variable charges are further elaborated in Table 3.

4. The norms prescribed by the KPRC for variable charges were differentiated on the basis of technology and hence provide correct signals to the generators (of each fuel type and technology) for reducing their variable costs. However such cost savings were not passed on to the consumers. On the other hand generating companies seeing the opportunities of self-dispatch continued to maximize the generation, sales and the profits at the cost of grid indiscipline.
5. These norms were subsequently adopted by GoI but were not reviewed from time to time as recommended by the KPRC report.

Tariff for Central Hydro Generating Stations

1. The fixed costs were proposed to be calculated as per those of the thermal stations.
2. The report states that since the incremental cost of generating hydro power is zero, all attempts should be made to absorb hydro power on a 100% basis, by backing down other forms of generation of power.
3. The report further proposes to treat hydro power stations as multi-product firms, where power from such plants is priced differently during peak and off-peak periods and during periods when water supply is surplus and when it has to be released for irrigation purposes.
4. Though these recommendations send signals for optimal and sustainable integration of hydro resources with the rest of the systems, these were not notified by GoI for Central Hydro Stations.

Annexe III

REGULATION 82 OF THE CENTRAL ELECTRICITY REGULATORY COMMISSION (CONDUCT OF BUSINESS) REGULATIONS, 1999

82. Without prejudice to the generality of the powers of the Commission in regulating the tariff of generation and transmission utilities the Commission may keep in view while determining the Tariff factors such as:

(a) the need to link tariff adjustments to increases in the productivity of capital employed and improvements in efficiency so as to safeguard the interests of the consumer;
(b) the need to rationalise tariffs on the basis of the actual cost of generation and transmission;
(c) the unbundling of costs so as to enable the rational allocation of costs;
(d) the need to transparently provide the appropriate incentives in a non-discriminatory manner for a continuous enhancement in the efficiency of generation and transmission and upgradation in the levels of service.
(e) the simulation of competitive conditions where markets do not exist and the progressive introduction of competitive conditions;
(f) the least cost adoption of environmental standards,
(g) the provision of a level playing field for all utilities so as to promote the progressive involvement of the private sector in generation and

transmission; and
(h) the need for healthy growth of the industry.

Annex IV

Sl.No.	Services	Provider (India)	Provider (in competitive markets)	Data Required for Tariff calculation	Quality of Data	Who is billing
1	Provision of trans-mission facility (Wires Business)	POWERGRID / Licensees	Transmission Service Provider	**(a)** DATA ON REGIONAL BASIS : 1. Debt 2. Equity 3. Cost of Long term Debt 4. Operation and Maintenance (in rupees per Year) 5. Taxes 6.Administrative and General Expenses (Rupees per Year) 7. Insurance (Rupees per Year) 8. Inflation rates for each period of study. **(b)** REGION – WISE ENERGY SALES DATA: 1. State Wise drawl of electrical energy On Frequency Linked Availability Tariff implementation : 1. MW share of each state; 2. Over / Underdrawals by the beneficiary states 3. Over/Under Generation by any generator	Fairly Reliable Yet to be established with special meters	POWERGRID / Licensees Mechanism for billing yet to be placed in position.
2.	Control Power Flow and Frequency	RLDC	ISO (Ind. System Operator)		Fairly reliable	POWERGRID (Consolidated with Overall Tariffs)
3.	Ensure System Reliability and Congestion Management	RLDC	ISO	The same as above for RLDCs		
4.	Energy Accounting and Billing	RLDC, REBs	ISO	Built into administrative charges	Basis not precisely defined	POWERGRID (Consolidated with Overall Tariffs)

5.	Provide Adequate Reactive Support and Voltage Control	Generator/ POWERGRID/ SEBs / STUs	Ancillary Service Provider	For reactive power generated by the generators, this is paid as a generation charge. Reactors/Capacitors providers by POWERGRID are built into the investment costs and treated as above. If these investments are for a particular state is required to pay for it.	Fairly Reliable. MVAR drawn by each state is recorded	POWERGRID (Consolidated with Overall Tariffs)
6.	Analyze and arrange for transactions[1]	REB	Power Exchange	Manpower, Hardware/software requirement, but not provided since tariff not charged	Does not arise	Not billed
7.	Investment Planning	CEA/ POWERGRID	ISO	Manpower, Hardware/software requirements, but not provided sice tariff not charged	Does not arise	Not billed

[1] These services are charged for in a market oriented power sector and provided by the system operator. Arranging power transactions is a function, which is likely to be performed by PTC in the future. Since the functions performed by PTC are not natural monopoly functions, competition can be allowed in the area of power trading.

Annex V

Transaction Type	Firm	Non - Firm	
		Curtailable	**As - Available**
Long - Term	Various commitments of the SEBs/Railways/other major consumers in the central sector power	The transmission service provider may interrupt service (only on specified conditions) at times other than those required for system emergencies.Such interruptions may result from scheduled or unscheduled facilty outages, transmission constraints, or economic opputunities to POWERGRID or its affiliates.	An SEB whenever it has a surplus may decide to sell power to its neighboring SEB
Short - Term	SEB requirement from Unalloacted central sector unallocated quota.		

The type of transmission services required for the provision of the transaction identified above are illustrated in the following table :

Transaction Type	Firm	Non - Firm	
		Curtailable	**As - Available**

Long - Term	(a) Provision of transmission facilty (incl. Reserve) (b) Provision of additional facilties, if necessary (c) Provision of adequate reactive supply and voltage control. (d) Billing and collection (e) Investment planning (f) Analysis and arrangements of transactions (g) Control power flow and frequency (h) Ensure system reliability and congestion management	Billing and collection Analysis and arrangements of transactions. These are basically the operating costs. Other service components, charged under firm transactions are relating to existing system costs, reinforcement costs. These services are nto required for non- firm transactions.	(a) Billing and collection (b) Analysis and arrangements of transactions. These are basically the operating costs. Other service components, charged under firm transactions are relating to existing system costs, reinforcement costs. These services are nto required for non- firm transactions
Short Term	Same as above		