

Electricity Reforms and Regulations
-A Critical Review of Last 10 Years Experience

Final Report

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Electricity Reforms and Regulations

- A Critical Review of Last 10 Years Experience

1.0 Introduction

Following the liberalisation and reform of the economy in 1991-92, the electricity sector too witnessed major policy and regulatory initiatives. The sector while it was growing rapidly in the eighties, faced issues of a debilitating and serious nature. Losses especially in distribution were large, efficiencies low, and tariff reform was long overdue. Tariff and subsidy policies, and the leakages that resulted inter alia from the tariff and subsidy policies severely affected the viability of the sector. Reform efforts, first the IPP policy which brought in private investments in a significant way, and later the institution of independent regulation, the Central Government's guidance and direction of reform efforts, unbundling of the sector to lead to corporatisation, legal initiatives to bring in competition, programmes to improve technical and operational efficiency of the sector to effectively procure power on a long term basis on behalf of state governments, have been initiated since then. The changes that these initiatives have brought about, while significant, have not necessarily been in the direction intended, and the core problems of leakage, viability of distribution, tariff reform and competition still remain to be addressed successfully.

It is in this context, the Forum of Regulators (FOR) appointed the Indian Institute of Management Ahmedabad as a consultant on 31st March 2008 to study the Electricity Sector Reforms and Regulations by undertaking a critical review of the experience of last 10 years with focus on constraints and gaps between the vision and achievements. This report is being submitted to FOR as an outcome of this study. Before outlining the contents of this report in this section, we would like to list the terms of reference of this study in detail.

1.1 Terms of Reference

Objectives:

This study seeks to achieve the following objectives:

- (a) To review the role of various authorities involved in the process of reforms in the electricity sector in India, more importantly, the role played by the Government (Central as well as State), Government agencies, the Regulatory Commissions, Appellate Authorities
- (b) Phase wise review of the above.

- (c) To assess the roles envisaged for various stakeholders including the Government (Central as well as State), Government agencies, Regulatory Commissions, Appellate Authorities
- (d) To outline the constraints and gaps on achievements of the objectives set.
- (e) To suggest the way forward.

Scope of work:

In order to achieve these objectives, the following will be undertaken:

- a) Step1: The starting point of the study would be the review of various phases of reforms in the electricity sector in terms of their objectives, since 1996. At this stage, the role envisaged (especially, in the Electricity Act, 2003) for various stakeholders including the Government (Central as well as State), Government agencies, Regulatory Commissions, Appellate Authorities would be clearly identified/delineated.
- b) Step 2: After identification of the objectives/strategies of reforms and the roles envisaged for various stakeholders, the study would focus on the achievements of the objectives set vis-à-vis the roles/responsibilities cast on the stakeholders.
- c) Step 3: At this stage, the study would focus on the constraints faced in terms of achievement of the objectives and the gaps between the vision, objectives and achievements. The study would also focus on the factors responsible for such gaps.
- d) Step 4: Based on the review of the analysis of Steps 1 to 3 above, the study would make a critical review of the impact of reforms initiatives of the Government and regulatory initiatives of the Electricity Regulatory Commissions on the Electricity Sector. At this stage, the study would also bring out how gaps in overall reforms initiatives have impacted the regulatory effectiveness and vice versa (i.e., how gaps in regulatory initiatives have impacted overall reforms process in the electricity sector).
- e) Step 5: The study would at the same time make recommendations on the way forward by identifying desirable action by the stakeholders like the Government (Central as well as State), Government agencies, Regulatory Commissions, Appellate Authorities, to achieve the objectives of the Electricity Act, 2003.

Methodologically, the study is based on documents available in public domain and the documents provided by various entities with the help of FOR secretariat. The study team visited several states (7) with help of FOR secretariat and interacted with officials of state government, SERC and utilities to gain insights on the issues faced in the process of implementation of reforms in the sector. A list of the states visited and officials with whom the team members met with is enclosed in the Annexure-1 of this report.

2.0 Background of the Reforms in the Sector

Post-independence, the Government of India decided to entrust the development of the electricity sector to respective states through the creation of State Electricity Boards (SEBs) under the Electric (Supply) Act of 1948. SEBs were expected to develop networks of transmission lines which till then had been quite rudimentary, and add generation capacity. SEBs were broadly expected to operate on commercial principles.

By the 70s, however, many of the SEBs started incurring losses because of many factors which included poor capacity utilization of the thermal plants put up by them. There were many reasons for the poor performance of SEBs direct political interference in SEBs operation by their respective governments, mismanagement, poor industrial relations, and shop floor practices. Flat rate tariffs, i.e., usage charges which were nearly zero, were introduced for agricultural connections – irrigation pump sets. The low tariffs herein were sought to be covered through higher tariffs on industrial and commercial consumers. But the dysfunctions and distortions of such cross subsidization, accelerated to result in increasing theft and leakages, loss of accountability of revenue and misreporting. Vested interests, dependent upon the subsidies and rents generated, emerged to politicize electricity tariffs and the management of distribution. Losses of the SEBs mounted and the expectation by the late eighties was as modest as SEBs should earn 3% on their equity capital. But even this proved to be difficult for most of them. Not only did SEBs not add sufficient capacities, but many were operating their generating stations far below the optimal. This made SEBs increasingly dependent on budgetary allocations from their respective governments reducing their ability to add generating capacity, and most importantly to carry out the periodic maintenance and upkeep of their distribution assets.

It was in such a situation that the central government set up two central sector utilities; NTPC for thermal generation and NHPC (National Hydro Power Corporation Limited) for hydro power. Annexure-2 compares the plant load factor (PLF) of SEBs and NTPC plants while Annexure-3 throws light on the financial performance of SEBs in early 1990s.

Given the deteriorating financial performance and poor operating performance of SEBs, the onus of setting up new generation capacities fell increasingly on central sector utilities. Over the 1980s, energy shortages and poor financial condition of SEBs continued. The need to control fiscal deficit led to initiation of reforms in the Electricity Sector in early 1990s with opening of the sector for private Independent Power Producers (IPPs).

In the backdrop of the balance-of-payment crisis in 1991, the Indian government decided to liberalize its economic policies. Many structural changes took place, including delicensing, greatly reduced trade barriers, and opening the door wide to foreign capital-both direct and portfolio. The need to control and

reduce the fiscal deficit following from macroeconomic structural adjustment considerations in the early 90s, inter alia led to the initiation of the IPP policy. Recognizing that electricity and other infrastructure sectors required substantial investments in the face of resource constraints because of fiscal tightening; the IPP policy was announced to allow investment by the private sector (including foreign capital) in electricity generation. Prior to this, save some private sector licensees operating in a few urban areas, the electricity sector was mostly in the hands of state electricity boards (SEBs) or central government owned utilities created to supplement the efforts of SEBs in generation and transmission sub-sectors.

3.0 Reforms in the Electricity Sector: A Review of Initiatives and their Objectives

3.1 The IPP Policy ¹

The Independent Power Project (IPP) policy was one of the earliest initiatives pre-dating the formation of independent regulators that came about following the stabilisation and structural reform of the Indian economy in 1992-93. The idea of using the private sector to add to investments in the electricity sector was meaningful since the state owned enterprises as a whole (and therefore in the electricity sector too) were put on tight leash in terms of the funds they could hope from the central government. The structural adjustment was based on large reductions in current public expenditure and the bulk of the adjustment was borne by cutting out the budgetary support for public investments especially those made by central PSUs and being earlier routed through the state governments – most notably investments in electricity sector by SEBs. IPPs, especially foreign owned, seemed like a good option since both the foreign exchange constraint and the fiscal problems could be overcome with such IPPs. Since the government was in a hurry and it was believed that legislative changes would take time, the IPPs policy was put in place through executive action alone. The need to quickly add capacities in the nineties to maintain and possibly enhance the growth was seen as being important since now with higher growth; electricity demand was expected to grow even more rapidly. The IPP policy therefore provided for MoUs between IPPs and the SEBs with the CEA clearing the projects in the usual way except that now the projects were to come from the private sector rather than from the central or state

¹ The discussion in this Section is based on Morris, Sebastian (1986), "The Political Economy of Electrical Power in India (Parts I and II)", *Economic & Political Weekly*, May 18 and 28, Vol. 31, Nos. 20 and 21.

owned sectors. Power was to be procured from the IPPs through long term agreements by the state level systems which till date were integrated natural monopolies. The policy as laid by the central government allowed a return of 16% on equity at a plant load factor (PLF) of 68.5%, when the return on equity allowed to the SOE power producers (NTPC and NHPC principally) was as low as 12%. Provisions for escrow cover, state government guarantees and sometimes even central government guarantees were negotiated by the IPPs that reached financial closure early under the so called 'fast-track' projects. It is interesting that the policy evoked the response of many players with practically every business group of any stature proposing an IPP or two with substantial planned addition to capacities. Over 235,000 MW of planned capacities in IPPs were being actively pursued by the private sector that included some international players including Enron and Southern Electric from the US whose proposals had reached financial closure. At that time, the total capacity of the utilities system was no more than 85,000 MW and including largish captive, the total installed capacity in India was under 100,000 MW. This large planned IPP capacity itself was reflective of the malaise in the policy. The policy in seeking to give a return of 16% on equity at 68.5% PLF could have given a return of between 24 to 28 % in reality since higher PLFs were eminently achievable by plants not subject to scheduling constraints. Equally importantly the return was higher since even after allowing for depreciation, return on constant equity was being provided for the life of the project when the depreciation rate was increased reflecting life of a plant as 12 years substantially below the expected life of the asset. Thus very large expected returns attracted potential investors who all knew that only the first few to get in would be able to have the contracts and PPAs to supply since the financial capacity of the SEBS, in the face of continuing losses and theft, to pay for electricity purchases would be limited. As such escrow cover and guarantees also became important. The lacunae in the policy were many and may be briefly listed as follows:

No distinction was drawn between base and peak load stations. Gas was allowed for base load stations without a comparative examination of lifecycle costs and the risks (especially on account of foreign exchange -price variation). Thus gas-based stations, with full pass through of fuel costs and with the risks on account of prices being borne by the buying utility, were allowed as IPPs under the specious argument that this was the only way to get some capacity addition quickly. In any case, no producer without captive access to basic fuels at sources could have been expected to bear the price risk. The fact that under most conceivable projections coal would always remain the fuel of choice for base stations was ignored. In other words under the policy the utilities while bearing the fuel price risk did not have the choice to chose the fuel at the level of the IPP.

Some of the IPPs being given a contract for off take of energy at nearly full achievable PLF would then earn stupendous returns as mentioned before.

The IPP policy also required the IPPs to source as much as 80% of the required investments from foreign sources. [The motivation in such a stipulation was perhaps to add to the foreign exchange reserves through an administered fix on the sources of funding at the industry level which in itself was bad macroeconomic management]. Firstly the large political risk and the “outcome risk” of negotiations with SEBs whose cash flows were in doubt for IPPs meant that foreign partners alone would find the going quite risky and would demand huge premiums. Indian developers though, since they had to borrow abroad under the policy, would be pushed into non-arms length relationship with equipment suppliers since they would have to depend upon suppliers credit, bilateral credit or exim credit from the country supplying the equipment. This tying of markets for credit and equipments necessarily resulted in higher cost of equipment.

Moreover since so many IPPs were planning entry, the price of equipment especially of gas turbines were bid up steeply in the international market raising further the cost of equipment

Since the projects were to come on the basis of negotiations rather than on competitive bids there were perverse incentives to pad the fixed costs, negotiate easy operational norms, and shift entirely the fuel price risk on the buyer. Similarly on the financial side there were no strong incentives to get the best terms.

In the case of IPPs with only foreign equity the dollar return of 16% (which was virtually guaranteed) meant double counting the premium due to the exchange risk since in the interest rates in India (which justified the 16% return) the expected depreciation of the currency is already incorporated by the market now that the rupee was fully open on the current account and portfolio capital was allowed free entry. It exposed unnecessarily the buyer to exchange risk on equity in an enterprise that could not have had foreign exchange earnings.

The most important limitation of all was that there was no way an IPP could have been a better option for the SEB than setting up its own base load station. Many SEBs had their base load station operating at over 80% with availability well over 90%. Some had even achieved plant load factors in excess of 95% for years at a stretch. These plants under cost plus regulation were earning at the implicit rate of return (12%) or at the rate of 3% on a capacity utilisation that was well above 80% in comparison to paying a private party at 16% on a costing PLF of 68.5%. Since there is no significant efficiency offset on operational norms either, it was a lose situation for the SEBs. Yet many SEBs accepted the adverse deals with the IPPs largely because the policy provided for the same, and the temptation to exploit the rent opportunities provided by the policy being large would have been very difficult to resist. The argument that SEBs needed to add capacity even if at high cost was often made in policy circles and discussions since it could be claimed with some justification that the marginal loss of power cuts was significantly greater than the cost of power. When the additional foreign exchange brought in on the

capital account due to 1 MW of capacity under IPPs is weighed against the cost of having to borrow to the tune of 20% of equipment costs for a domestic project, then cost of the additional foreign exchange inflow was as high as 40% if the tying of equipment to credit and the increased use of foreign sources of equipment is recognised. This was well above the cost of borrowing in the international market by even a failing state; leave aside the cost of borrowing for the Indian state.

What finally allowed the SEBs to tide over the IPPs was their own limitation in being able to service the IPPs, since their cash flows on account of subsidisation, leakages, losses and theft were insubstantial for them to actively consider more than a few IPPs. So what materialised as IPP capacity was a far cry from the actively pursued 235,000 MW. Financial closure was possible for about 15,000 MW capacity of IPP for the whole of India. Additionally, the policy itself had changed. IPPs were by the late 1996 required to be set up with the return in excess of 16% being negotiated by the SEBs. In other words, the costing PLF could move closer to the 80% (the reference PLF of the base load stations of the utility itself). The requirement of 80% foreign funding was also removed. Most important of all the IPPs were now to come up only on the basis of competitive bids. These measures reduced considerably the scope for rents and at least put the buyer and the seller in a bargaining position.

Nevertheless considerable cost was imposed on the SEBs in the IPPs that they had already contracted for. Thus Maharashtra was saddled with the hugely adverse Dabhol Project, Gujarat with several IPPs based on high cost naphtha, and most states with smaller IPPs using often second hand equipment and based on liquid fuels. Thus an examination of the life cycle of IPPs through a least cost capacity addition model for the Northern Grid, revealed that the IPPs if they were to be completely scheduled would impose an additional cost of close to 15% of the total cost of power supply (for the same amount of power when optimally developed) of the Northern System. And if they were not scheduled but allowed to earn their return of 16% without being scheduled then the additional cost would be close to 7%.²

The demand risk in IPPs was being shouldered entirely by the buyer. While IPPs had meaning at the margin and in a situation where they could supply power cheaper than the embedded generators in utilities, there was really no role for IPPs in a situation where the integrated utilities continued. The earlier PURPA of the US which had created the space for IPPs was under a very different situation of long years of regulatory capture by utilities under cost plus which had made the cost of

² Paul, Pallavi (1998), "Investment Options and Least Cost Planning in the Electricity Sector in India", Doctoral Dissertation, Indian Institute of Management Ahmedabad.

generation of embedded generators higher than that of stand alone generators. The problem in India was not at all in generation but in distribution and addressing the same through the IPPs, was clearly a mistake.

The mistake in the policy stemmed from not addressing the core problem; and confusing the marginal PLF with the average PLF of an integrated utility, and a power procurement process that violated procurement principles, amplified the risk by de-facto reversal of the correct risk assignment. Thus significant business risks were being borne by the buyer (government) while the promoter ended up bearing political risk!

India, being a democracy, such sweetened PPPs despite the policy could not have been institutionalised. The policy invited much criticism and had to be modified. That also limited the damage that the IPPs actually placed on the system. Without the critique and the subsequent modification in the policy the damage could have been many times more than that inflicted on the system.

3.2 Early Unbundling and Privatization Initiatives by States

Even as the IPP policy was being operationalised, the idea that the inefficiencies of the SEBs could be overcome by unbundling and privatisation was pursued. The initiative in this direction came largely from the multilateral agencies including the World Bank and the Asian Development Bank. These agencies besides providing for the services associated with unbundling - consultancy services for laying out the frame work, process consultancy for privatisation, studies to develop financial plans for restructuring etc. - also laid out significant amounts by way of low cost loans to the SEBs. There was also much that was wanting in the understanding of the consultancy firms that developed the framework for unbundling during this period.

Since this happened at a time when the budgetary provisions of the centre were under stress, many state governments picked up "reform" as conceived by these multilateral agencies, as an agenda with the principal element being the unbundling. Unbundling was seen as a necessary prior condition for privatisation. The early studies "showed" the need for significant upping of the tariffs since the leakages and technical losses were projected to continue. Orissa was one of the earliest states to pursue unbundling and unlike many others, followed it up with privatisation of the distribution companies with the transmission company being still in state hands. From the Orissa experience emerged the so called single buyer model of unbundling. This involved the following:

- Unbundling of the vertically integrated SEB into a few DISCOMs, one or more GENCOs, a TRANSCO that besides carrying out transmission functions also played the role of a buyer and seller of power from the generators and to the DISCOMs respectively.

- Cleaning up the balance sheets of all companies so that the future operations could be on a cash flow consistency basis.
- Attempting to sell the DISCOMs and GENCOs to the private sector
- A residual SEB in some cases rather than the TRANSCO itself carried the residual liabilities including contingent liabilities that could not be allocated to the unbundled companies.

Given the lack of clarity on the treatment of cross subsidies the model did little to help potential investors understand the future of the sector. DISCOMs bore significant supply risk and GENCOs demand risk, had they to be independent businesses since there was no legal framework other than a possible power supply agreement to determine the relationship among the players.

There was no regulatory clarity on not only the treatment of subsidies, but also on the cost of power procurement and the supply requirements. And more importantly no trajectory for tariff reform or the treatment of cross subsidies, or of the regulatory framework was laid out. As a result, the regulatory and policy risks were quite overwhelming and it is not surprising that there was little response to the Orissa model once all these risks manifested or were sensed and assessed by the private sector.

In Orissa itself despite large returns possible with T&D loss reduction by the now privatised DISCOMs, the provisions of the contract were such as to heighten contract failure risk. The DISCOMs could not really target T&D loss reduction since this was not sufficiently incentivised for either the companies or for the staff. The revenue leakages continued and soon enough the balance sheets of the DISCOMs were muddied with receivables from consumers, and of the TRANSCO with receivables from the DISCOMs.

Andhra which also followed the single buyer model without privatisation also had its TRANSCO carrying the receivables and losing its net worth. In this case, the government of AP was committed to paying to keep the system afloat. Here though for the reason that the DISCOMs were not privatised the contract failure risk was not there. Lately when administrative pressures were put on the DISCOMs to improve their performance especially financially, modest and unsustainable improvements were realised for a short period.

Haryana one of the early states in unbundling had a similar experience with the balance sheets of the DISCOMs again getting muddied with little or no improvements taking place. In all these efforts, the unbundling was not part of a larger effort at creating competition through open access. There was also no blueprint or game for the coherent and coordinated operation of the various segments of the business. Therefore it is not surprising that the unbundling as such

was more in form than in content. If the same was more actively and functionally pursued as in the case of Orissa or AP, it may have only compounded the problem. Given the vast problems of lack of control, political interference, and tariff anomalies, and all the problems of differential tariffs to cross-subsidize, none of which were addressed; the mere unbundling of SEBs was of little consequence.

Given (1) the precarious financial situation of the DISCOMs, (2) the heightened demand and supply risks that the GENCOs and DISCOMs would face when unbundled, (3) lack of clarity on tariff determination, and more generally regulatory uncertainty, (4) little or no clarity on the targets for loss reduction and the basis for the measurement and determination of losses, there was no way the DISCOMs could have been privatised without massive risk shifting on to the residual SEB, or the TRANSCO. Even such privatisation would have been subject to contract failure. GENCOs though could have been privatised had there been a regulatory framework and clarity about the future allowed return (under cost plus) or if there had been something akin to a multiyear tariffs in place or price cap regulation.

3.3 Distribution Losses and CMs' Conference in 1996

From post Orissa privatization experience, and studies undertaken by World Bank and others, it became evident that the T&D losses reported by the SEBs were low because assessed consumption for agriculture and elsewhere was estimated at much higher level than what was the reality. The studies indicated that the AT&C losses (losses including commercial theft or non-payment) were higher than 40% in most states. The problem was becoming serious. To address some of these issues and to get the states on board, the first Chief Ministers' conference was organized in December of 1996. Later similar conferences were organized in 1998 and 2001.

One of the important decisions taken in the 1996 conference was to charge at least 50 paise per kWh from farmers for agricultural consumption and to move towards charging 50% of the cost of supply. Given the political sensitivities, however, no major change took place on this front. And in the 2001 conference the PM had to regret that the decision taken in 1996 was not yet implemented by many states. The 1996 conference resulted in Common Minimum National Action Plan for Power and envisaged setting up of regulators in the sector. By 1998, however, the changes in political equations resulted in change in the stance on agricultural subsidy. Instead of minimum of 50 paise per kWh and a time frame of three years to move towards 50% of cost of supply, the insistence was limited to State Government paying subsidy to the SEB in case it wanted to supply free power to farmers.

3.4 Independent Regulations: ERC Act of 1998

As the entities got unbundled and the role of the private sector in electricity was set in motion through the IPPs and in one state - Orissa - in distribution as well, the need for independent regulators was obvious since now there was private sector when the state itself had a significant market role. Since electricity was a concurrent subject under the constitutional framework and the authority to set prices was with the state government, the need for regulators at the state level was obvious. The regions rather than the states would have been the more appropriate level for price regulation since the connectivity within the region was thick and some of the states were too small. Under the ERC Act 1998, the centre was to cover tariffs related to interstate movement of power and regulate all entities that operated under one identity across many states (These were the PSUs- NHPC, NTPC, PGCIL and some others). Other entities that operated across states -BBNL, DVC continued to be governed by their earlier framework. And all state level entities were now governed by the SERCs. The earlier licensees like CESC, AEC, SEC, and BSES were brought under the appropriate ERCs.

The ERC Act of 1998 was a legislation aimed towards creation of independent regulators in the sector, where unbundling, privatization and other reform measures were already on the national agenda. The need for independent regulations was already felt and was part of Common Minimum National Action Plan for Power. The objectives of the act, as stated therein, were “to provide for the establishment of a Central Electricity Regulatory Commission and State Electricity Regulatory Commissions, rationalization of electricity tariff, transparent policies regarding subsidies, promotion of efficient and environmentally benign policies and for matters connected therewith or incidental thereto”.

The Act envisaged two layers of regulators in line with the reality in the sector governed under Electric (Supply) Act of 1948, which envisaged key role for state governments in the distribution sector. The functions and jurisdiction specified for the central regulator in the act were:

- (a) to regulate the tariff of generating companies owned or controlled by the Central Government;
- (b) to regulate the tariff 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 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 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 that Government.

Unlike the Electricity Act of 2003 which was expected to come later, there was no provision of an Appellate Tribunal in the ERC Act and hence appeal against any ruling or order of CERC and SERCs could be filed in High Courts.

Similar to CERC (the central regulator), the functions of the SERCs specified in the Act were:

- (a) to determine the tariff for electricity, wholesale, bulk, grid or retail, the case may be, in the manner provided in section 29;
- (b) to determine the tariff payable for the use of the transmission facilities in the manner provided in section 29;
- (c) to regulate power purchase and procurement process of the transmission utilities and distribution utilities including the price at which the power shall be procured from the generating companies, generating stations or from other sources for transmission, sale, distribution and supply in the State;
- (d) to promote competition, efficiency and economy in the activities of the electricity industry to achieve the objects and purposes of this Act.

In addition to the above, any of the following functions could be performed by the SERC in case State Government notified them:

- To regulate the investment approval for generation, transmission, distribution and supply of electricity to the entities operating within the State;
- To aid and advise the State Government, in matters concerning electricity generation, transmission, distribution and supply in the State;
- To regulate the operation of the power system within the State;
- To issue licences for transmission, bulk supply, distribution or supply of electricity and determine the conditions to be included in the licences;

- To regulate the working of the licensees and other persons authorized or permitted to engage in the electricity industry in the State and to promote their working in an efficient, economical and equitable manner;
- To require licensees to formulate perspective plans and schemes in coordination with others for the promotion of generation, transmission, distribution, supply and utilization of electricity, quality of service and to devise proper power purchase and procurement process;
- To set standards for the electricity industry in the State including standards relating to quality, continuity and reliability of service;
- To promote competitiveness and make avenues for participation of private sector in the electricity industry in the State, and also to ensure a fair deal to the customers;
- To lay down and enforce safety standards;
- To aid and advise the State Government in the formulation of the State power policy;
- To collect and record information concerning the generation, transmission, distribution and utilization of electricity;
- To collect and publish data and forecasts on the demand for, and use of, electricity in the State and to require the licensees to collect and publish such data;
- To regulate the assets, properties and interest in properties concerning or related to the electricity industry in the State including the conditions governing entry into, and exit from, the electricity industry in the such manner as to safeguard the public interest;
- To adjudicate upon the disputes and differences between the licensees and utilities and to refer the matter for arbitration;
- To co-ordinate with environmental regulatory agencies and to evolve policies and procedures for appropriate environmental regulation of the electricity sector and utilities in the State; and
- To aid and advise the State Government on any other matter referred to the State Commission by such Government;

It was clearly specified in the section 22(2) of the Act that the SERC would exercise its power in conformity with National Power Plan. Section 29(2) also specified that the tariffs would be determined by the principles provided in Electric (Supply) Act of 1948, which in essence were based on “cost-of-service” tariff principles. It further specified that the tariff progressively reflects the cost of supply of electricity at an adequate and improving level of efficiency. Though less binding, section 28 of the Act also required CERC to follow the schedule VI of the ES Act of 1948. The CERC started functioning and instituted Availability-based tariffs to promote discipline in the regional grid by creating commercial incentive. It also came out with tariff orders for the CPSUs for the period beginning 2001. Some of the states, which had moved towards reforms, constituted the SERCs.

3.5 Reducing Payment Risks: MS Ahluwalia Committee

The core problem of the SEBs not generating sufficient revenue to pay the suppliers of electricity had become serious by the year 2000. The receivables from the SEBs to the NTPC and the CPSUs more generally reached astronomical levels threatening the viability of upstream players including their ability to expand capacities and the network. Being owned by the central government, any threat on the part of CPSUs to supply power to defaulting SEBs, was incredible. The SEBs on their own assets could realise just sufficient to be sustainable on a cash basis but on power purchases from NTPC and NHPC, they could not play the game of “cash viability”. Their payables to CPSUs had crossed over Rs. 41,000 crore including more than Rs. 15,000 crore of interest/surcharge. In such a context, an expert group under the chairmanship of Sh. M S Ahluwalia, Member, Planning Commission, appointed by the Government of India submitted its report in May, 2001. The group noted that the dues are not due to problems of the past but because of continuing non-viability of the current operations of SEBs. Accordingly, the Committee stressed that any resettlement of past dues should be linked to a mechanism that would ensure credibly payment of dues in the future. The specific measures suggested by the group were-

- For the states participating in the resettlement scheme, the interest/surcharge be waived to the extent of 50%. This would bring down the outstanding to around Rs. 33,600 crore.
- Around Rs. 35,000 crore of State Government bonds with 8.5% tax-free interest having principal payment moratorium of 5 years with repayment between 6th and 15th year be issued to settle their SEB dues. The bonds would be identical to their market borrowings to ensure discipline and the holder will not sell more than 10% of such bonds in a year.
- Default in payment in future would result in reduction of power and coal supplies. If the payment is not made in 90 days, it should be adjusted against dues to the state from Ministry of Finance of the Central Government.
- As a part of the settlement, the states/SEBs should accept the reforms such as setting up SERC, metering feeders and increasing revenue realizations. MoUs by each of the State Governments would be entered with Ministry of Power for this.
- The CPSUs would offer an incentive of 2% of the bond value twice a year for next four years, and a one-time incentive of 2% if the SEB opens and maintains LC till December 2001.
- The scheme should be operative only if at least half of the states having billing of more than Rs. 500 crore from CPSUs give their consent.
- The states who withhold their consent would be denied central allocation of 15% and assistance from APDP (later, APDRP). Their supply and coal allocations would also be reduced.

The scheme was accepted and implemented with multiple effects: (i) It did lessen the problem of receivables for the CPSUs going forward; (ii) it increased collection efficiency of the SEBs as the states had to bear the cost of profligacy of their SEBs; and (iii) it allowed some leeway to the central government to provide thrust to reforms at the state level.

The Central government realising that there was no way the SEBs (and the state governments) could be held completely accountable, came out with debt rescheduling and debt forgiveness that could hopefully curb the problem of receivables from the SEBs. The interest accumulated on the receivables had to be largely written off by the NTPC and NHPC; central government forgave part of the debt, and converted to bonds a part. Going forward it made the provision that in case payments were not received in time, the CPSUs could interrupt the Plan funds flow from the Planning Commission. Although the centre had to bear large losses and the scheme was unfair to the SEBs that had been paying regularly or did not have to buy from the CPSUs, it was possibly the only fix and the provision of interrupting the Plan funds was crucial to solving the problem of the receivables of CPSUs from the SEBs.

3.6 APDRP: Strengthening Distribution Network and Reduction in Distribution Losses

The Accelerated Power Development Reforms Programme (earlier known as Accelerated Power Development Programme or APDP) was launched in 2002 with the objective of “upgradation of sub-transmission and distribution in densely electrified zones in the urban and industrial areas and improvement in commercial viability of State Electricity Boards”. It has two components- (a) investment component for strengthening the distribution system, and (ii) incentive component to motivate utilities to reduce cash losses.

The investment component of the APRDP would fund 100% of the approved APDRP project cost for special category states with grant: loan ratio of 9:1. For other than “special category” states, APDRP investment component would fund 50% of the approved APDRP project cost with grant: loan ratio of 1:1. For investments, the utility would prepare a detailed project report based on a manual prepared by the expert committee, which will be evaluated techno-commercially by NTPC or PGCIL acting as advisor cum consultants to Ministry of Power. The project would have emphasis on using IT for revenue increase, outage reduction, segregation of technical and commercial losses, controlling commercial losses, for meter reading, billing, collection etc. The States would have to sign a Memorandum of Agreement with Ministry of Power for release of APDRP funds. The MOA was supposed to put pressure on the state systems to meter feeders, increase the coverage of consumer metering, ensure energy accounting, improve accountability through

appointment of feeder managers, and formally sign “MoUs” with circle level managers etc.

On the incentive component, the APDRP used 2000-01 as the base year for incentivising the loss reduction. Fifty percent of actual loss reduction by the SEB/utility was receivable as grant from the Central Government. The losses were to be computed net of any subsidy given by the State (in base and subsequent years).

3.7 Comprehensive Legal Framework for Reforms: The Electricity Act of 2003

The year 2003 marked a new beginning of reforms in the Electricity Sector in India with enactment of the Electricity Act replacing the legal framework for the sector hitherto governed by the Electric Supply Act of 1948 and the ERC Act of 1998.

Its objectives as stated in the preamble were “to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity and generally for taking measures conducive to development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas, rationalisation of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies, constitution of Central Electricity Authority, Regulatory Commissions and establishment of Appellate Tribunal and for matters connected therewith and incidental thereto”.

The salient features of the Act are:

- State Government to unbundle the sector with transmission and system operation made independent of any other businesses in the sector, viz., generation, distribution, and trading.
- No requirement of license for generation and no requirement of techno-economic clearance except for large hydro-generation projects.
- Captive generation capacity to have open access to the transmission system and not subject to any regulations for its pricing. Definition of captive generators liberalized to include any capacity set up by an association of persons.
- All others- transmission, distribution, and trading require licence from the regulators (CERC or SERCs) depending upon the area of their operations.
- Independent regulators to regulate the sector including award and revoking of licences, tariff setting consistent with National Electricity Policy, defining and enforcing performance standards and quality of service, and setting Grid Standards.

- Creation of regulatory fund at the central and state level with accountability to the Parliament and Legislature respectively.
- Regulators to reduce cross-subsidies and move towards allowing open access to a class of consumers in a phased manner.
- Multiple distribution licensees allowed for distribution.
- State Government to pay subsidy in advance. And tariffs to revert back to levels determined by the ERC, if the subsidy is not paid.
- Stringent measures for theft and unauthorized use of electricity including creation of Special Courts for dealing with such cases quickly.
- Insistence on 100% metering within two years of enactment.
- Appointment of an Ombudsman and creation of Consumer Grievance Redressal Forum for consumer interest protection.
- Establishment of Appellate Tribunal to fast-track the appeal process on rulings of ERCs with Supreme Court being the final arbiter.
- CEA to be the body for techno-economic clearances of large hydro projects, for planning (National Plans) and for advice and definition of technical standards.

Clearly the main aim of the Act was to promote competition through competitive generation, captive generation with open access, inter-state and intra-state trading, and competition in distribution through open access and/ or multiple licensees. This, along with measures such as metering, universal access, independent regulations, theft control, reduction in cross-subsidies were aimed at improving operational and financial performance of the entities in distribution and other parts of the sector. A more detailed discussion on the role envisaged of key players in the sector- the Governments, the Regulators, the CEA, the Appellate Tribunal, the CTU and the STUs, and the load dispatch centres is elaborated later in the report in section 4.

3.8 National Electricity Policy

In pursuance of the provisions of the Electricity Act 2003, the Central Government came out with National Electricity Policy on 6th February 2005. The policy recognizes the following-

- Around 44% of the households do not have access to electricity according to Census 2001.
- Electricity is an essential requirement. Supply of electricity at reasonable rate is important for rural development. So is the availability of quality supply at competitive rates to industry and services sectors. It is a driver of economic growth.

- Demand has outstripped supply and cross-subsidies have risen to unsustainable levels. There are inadequacies in generation, transmission and distribution including lack of commercial orientation in utilities and high AT&C losses.
- Electricity industry is capital intensive and has long gestation periods and the sources of energy are unevenly dispersed across country.

In order to alleviate some of the issues diagnosed and stated above, the policy prescribes the following objectives:

- Providing universal access in next five years for which significant capacity addition and expansion would be required.
- Meeting the demand fully by 2012 and to have spinning reserves after meeting peak requirements.
- Bringing about improvements in quality of supply at reasonable rates.
- Increasing per capita availability to over 1000 kWh per year by 2012.
- Ensuring a minimum lifeline consumption of 365 kWh per year per household as a merit good by 2012.
- Financial turnaround and attainment of commercial viability of all entities in the sector.
- Protection of consumers' interest.

The National Electricity Policy spells out the details on some of the challenges ahead under various headings. These are discussed below:

On Rural Electrification

Having stated the objective of universal access, which is also consistent with Section 6 of the Act, the policy document envisages creation of Rural Electrification Distribution Backbone (REDB) having at least one 33/11 kV sub-station in each block on the state network. The feeders from the REDB would cover every village from where the connections can be given to each household on demand. Wherever it is not possible, the distributed generation with local distribution can be provided. Rural Electrification Corporation of India would act as a nodal agency at the Central Government level and the Government would also provide soft loans and capital subsidy for expanding the network. However, the utilities need to recover cost of supply from all, save BPL consumers to whom alone the subsidies need to be directed. The task is challenging and requires coordination across entities and governmental agencies.

On Generation

The policy document envisages capacity addition of more than 100,000 MW during 2002-2012, in order to meet the objectives of over 1000 kWh availability and 5% reserves assuming 85% availability of capacity. On the hydro-generation side,

the policy document mentions initiative launched for 50,000 MW capacities but identifies need for active interest on the part of states having hydro potential, importance of R&R/environment protection and availability of long tenor of debt. On the thermal generation side, the policy document recognizes the dependence on coal as primary fuel. It envisages coastal imported coal based plants, domestic coal based and lignite based plants near pitheads and gas based plants using indigenous gas. It is open-ended about imported LNG based capacity additions but envisages shift from liquid fuels to gas/imported regasified LNG. It allows for medium to long term fuel supply contracts for commercial viability and supply security and envisages new capacities to be either at pitheads or at the demand centres. It envisages greater share of nuclear power through private sector participation and also for non-conventional sources of energy.

The policy document also spells out the need to get captive and standby generation capacity to contribute to the grid by bringing them on to grid and to have commercial arrangements between captive generators and licensees for the spare capacity with captive generators. This needs to be encouraged by the regulators. It also mentions the need for R&M for old capacities, closure wherever not economically feasible and replacement of management when a capacity is not utilized optimally.

On Transmission

The policy document recognizes the need for development of National and State Grid for which CTU and STUs need to coordinate. The network expansion by the CTU and STUs can be done without any prior agreements with licensees keeping in mind the current and future requirements of the sector. The SERCs need to specify Grid Code by September 2005 for smooth and efficient operation of the network. It recognizes the importance of non-discriminatory open access to the transmission system and distribution networks for promoting competition among generators and in the market. It also recognized the need for creating state-of-the-art SLDCs in line with RLDCs by June 2006. The document also recognizes that NLDC, RLDCs and SLDCs should ensure independent system operation and the STUs should not trade in accordance with the Act. It envisages creation of adequate margins (surplus) in transmission capacities for secure and reliable operations. It states that Regional Power Committees and NDLC would be notified soon in accordance with the provisions of the Act.

On Distribution

The policy document underscores what is widely recognized as the most problematic part of the Indian Electricity Sector undermining its commercial viability. It restates that in accordance with the Act, the states need to restructure

the distribution utilities without burdening them with past liabilities and extraneous interference but with appropriate organisational structure and process making them accountable. In this effort, the Central Government would support the states having clear roadmap. The document emphasises the need for SERCs to provide for open access to consumers with peak requirement above 1 MW by January 2009 and to use Multi-year Tariff principles to incentivize the efficiency gains. SERCs should also encourage private sector participation in the distribution sub-sector, for which they can be given second and competing licence for any revenue district, municipal council or municipal corporation as minimum area. They would have USO obligation and the SERCs should regulate connection charges to avoid cherry-picking by the second licensee. The document also lays emphasis on segregation of technical and commercial losses through energy accounting by March 2007, on metering including pre-paid meters and TOD meters (for large consumers), on third-party meter testing, on use of IT for consumer indexing and mapping, on SCADA for efficient management of the system, and on detection and prevention of theft through HVDS and implementation of the stringent measures specified in the Act. SERCs and the State Governments, as per the document, are expected to play key roles in attainment of these and they would be supported by the Central Government through schemes such as the APDRP.

On Recovery of Costs and Subsidies

The policy document recognizes the need to recover costs of supply and also the need to provide cross-subsidies to consumers who are very poor. The minimum charges from such category should be still 50% of the cost of supply. In case, the State Government wish to provide subsidies to any group of consumers, they should do so within the provisions of Section 65 of the act by paying in advance without affecting the utility financially.

On Competition and Private Participation

The policy backs up the objective of introducing competition in the sector as envisaged in the Act by laying emphasis on market development through new capacities being built with some part not tied up through long-term PPAs. It envisages inter-state trading by licensees having licence granted by CERC, introduction of intra-state ABT in one year by SERCs, by entry of captive capacity into the market, creation of power trading markets under regulation from CERC and SERCs.

The private sector participation is envisaged as the investment requirements of the sector are expected to be huge. Even though the public sector entities should raise internal resources, the ERCs should allow appropriate returns on investment, which are attractive enough to attract private sector investment at par with other

sector given the risks. For this, the tariffs may have to be rationalized. The regulatory risks should be minimized to attract private sector investments and the regulations should promote efficiency through competition. One route for the same as laid out in the Act is open access. The cross-subsidy surcharge and the recovery of fixed charges of the distribution licensee should not be set by the ERCs to become onerous and which result in thwarting competition through open access. The Central and State Governments should evolve models for successful private sector participation in the sector.

On Other Issues

In addition to these issues, the policy document lays emphasis on need for coordination for optimum development of the sector, use of IT, research, development and commercialization of non-conventional sources of energy, development of super-critical and IGCC technologies, large generating capacities with economies of scale, high voltage transmission technologies, control system. It stresses on the need to evolve a suitable funding mechanism for funding R&D in the sector including setting aside a share of profits by the large companies for R&D.

It also lays emphasis on energy conservation and demand side management for reducing the energy requirements and attaining higher efficiencies. Periodic energy audit for power intensive industries as per the Act needs to be done and BEE (Bureau of Energy Efficiency) should initiate measures for demand side management and energy conservation measures. The load curve can be flattened by TOD tariffs initiated by ERCs and ERCs should insist on energy efficiency standards from the utilities. It also recognizes the need to improve energy efficiency of agricultural pump sets.

The policy underscores importance of share of non-renewable sources of energy and also in bringing down the cost of electricity generated from such sources. ERCs, as per the Act, can prescribe the share of such energy, including cogeneration, to be procured competitively by the distribution licensees and can set differential (higher) prices.

The policy document also points out the importance of properly trained human resources in the sector including in the ERCs. It states the importance of ERCs and State Government and need for coordination to achieve the objectives laid out in adding capacity and strengthening the system, restoring financial health for providing universal access and improving quality of supply. To improve the quality of supply, ERCs as per the Act need to define performance standards and layout a road map for declaration of Reliability Index for all cities and towns up to district headquarters. The CEA would publish the same after compiling it. To

protect consumer interests, SERCs should set up Grievance Redressal fora and the regulations regarding Ombudsman within six months.

3.9 Electricity Rules, 2005

In pursuance with section 176 of the Electricity Act, which empowered the Central Government to make rules for carrying out the provisions in the Act, the Central Government notified Electricity Rules, 2005 on 8th June 2005. Certain amendments were later made in these rules on 26th October 2005.

The rules cover the requirements for classifying captive generation plant, coverage of asset/network items under distribution system, compliance with the direction of transmission licensee, surcharge on transmission fee, constitution of grievance redressal forum and appointment of ombudsman, clarity on regulation of generation tariff between CERC and SERC, clarity of inter-state and intra-state trading license, clarity on time period for appeal to appellate tribunal, clarity on jurisdiction of special courts vs. other courts in the absence of constitution of special courts, cognizance of an offence etc.

On captive generation, these rules specify that any plant in which more than 26% equity is held by the captive user(s) and more than 51% electricity on annual basis is consumed for captive use will be classified as a captive generation plant. This definition would hold collectively for members of a registered co-operative society and also for association of persons. According to a clarification issued by the Central Government on 6th August 2007, such plants would have open access under Section 9(2) of the act subject to availability of adequate transmission facility and would not have to wait for open access being declared for certain class of consumers by SERCs under Section 42 of the act. The rules also clarified that in case a plant has multiple units the same principle can be extended to a single unit of a sub-set of units provided the above conditions are met on pro-rata basis.

The rules clarified that mere incidental use of parts of distribution system for transmission would not render them as not part of distribution system. The rules also specified that the direction given by load dispatch centres are binding on transmission licensee failing which all penal measures can be taken by the ERCs including taking control of their operation. The rules clarified for any consumer entitled to open access by the SERC and using inter-state transmission, the surcharge determined by CERC for inter-state transmission would be in accordance with the surcharge on wheeling determined by the SERC. The rules laid out the process of formation of forum for redressal of consumer grievances, which would consist of licensee officers and an independent member nominated by the SERC, under the guidelines issued by the SERC. It also specifies the duty of the ombudsman to address grievances and to report compliance by the licensee to the SERC and the State Government. It clarifies that the generators for whom the tariffs

are set by the CERC, the SERC will not regulate their tariffs but will have to decide whether the distribution licensee should procure power from such generators or enter into PPA with them. It clarifies that once a trader obtains inter-state trading license, the trader also can trade intra-state without obtaining a separate license for intra-state trading. It clarifies that till special courts are constituted for the sector, other courts will continue exercising their jurisdiction on the relevant provisions of the act.

3.10 National Electricity Plan

In pursuance with Section 3(4) of the Electricity Act 2003, the CEA came out with a National Electricity Plan after consulting various stakeholders, which was notified on 3rd August 2007. The plan covers 10th, 11th and 12th Plan periods. The plan is based on demand forecasts of the 17th Electric Power Survey and the economy's GDP growth rates projected in the Integrated Energy Policy and the objectives laid out in the National Electricity Policy. In the volume I covering Generation and related aspects, the plan envisages feasibility of capacity addition requirement of 78530 MW during 11th plan (16553 hydro, 58597 thermal and 3380 nuclear). For the 12th plan, it projects requirement of capacity addition of 82000 MW (30000 hydro, 40000 thermal and 11-13000 nuclear). Therein it also covers the requirement of likely inputs and other measures such rural electrification, environment, DSM and energy conservation. In volume II of the plan on development of transmission system in the country, it is envisaged that inter-regional grid has to expand from capacity of 14100 MW at the end of 10th Plan to 37700 MW at the end of 11th Plan. It also covers the likely transmission capacity addition during early 12th Plan period and issues related to transmission system for merchant power plants, evacuation of power from North Eastern region, and synchronization of all five regional grids.

3.11 Tariff Policy

In pursuance with section 3 of the Electricity Act 2003, the Central Government notified the Tariff Policy on 6th January 2006. According to the Act, the CERC and SERCs are to be guided by the Tariff Policy in framing its regulations. Also, the SERCs are expected to follow the principles and methodologies specified by the CERC for generation and transmission. Forum of Regulators is expected to facilitate consistency across SERC regulations especially in distribution. The Tariff Policy recognizes that it is important to balance the requirement of providing fair and appropriate return on investment to attract investments in the sector and to ensure

reasonability of user charges for the consumers. Accordingly, it lays out the following objectives:

1. Ensuring availability of electricity to consumers at reasonable and competitive rates;
2. Ensuring financial viability of the sector and attracting investments;
3. Promoting transparency, consistency and predictability in regulatory approaches across jurisdictions and minimizing perception of regulatory risks;
4. Promoting competition, efficiency in operations and improvement in quality of supply.

The Tariff Policy Document discusses general approach to tariffs before specifically addressing sector and sub-sector specific issues. These are detailed below:

General Approach to Tariff

The Tariff policy reemphasises the importance of competition and creating conditions for competition in line with the Act and the Electricity policy. Towards this end, it specifies that the distribution licensees would procure power (or capacity) competitively for medium and long-term from generators under the procurement guidelines notified on 19th January 2005 through tariff based bids instead of MoU except from PSU generators. Even PSU generators would have to bid competitively after five years or when the ERC feels that the time is ripe for introducing competition. In case of existing private generators, one time capacity expansion of not more than 50% is also exempted from this requirement. It recognizes that the wires part of the sector would have to be regulated on regulated returns basis being a natural monopoly. Save competitively procured power, it adopts “cost of service” regulation for the sector.

As far as return on investment is concerned, it allows CERC to follow either cost of equity approach as in the past or cost of capital approach in case it deems fit. The returns should attract investment in the sector at par with returns in other sector adjusted for risks. The surplus so generated is viewed as important not only for attracting investment but also for growth of the sector. The CERC has to notify the rate of return on equity or capital for generation and transmission keeping in view the prevalent cost of capital and the same would be followed by SERCs. ERCs, according to the policy, have to ensure that the capital costs are reasonable and to this end may evolve benchmarks. The SERCs may follow ‘distribution margin’ approach in future at an appropriate time and the FOR should evolve within one year a comprehensive approach towards the same. The ‘distribution margin’ approach should factor in reduction in AT&C losses, cost of supply and quality.

The Tariff Policy specifies debt-equity norm of 70:30. In case equity is more, the excess should be treated as debt but if it is less than the norm, then the actual equity should be considered for tariff fixation. There should be no need for advance against depreciation and the CERC may notify the depreciation rates for generation and transmission, which can be suitably modified for distribution by the FOR. The depreciation would be same for accounting and tariffs. The benefits of fully depreciated assets should be available to consumers. The ERCs should incentivize the debt restructuring wherever it is beneficial to consumers. The foreign exchange risk should not be allowed as pass through and should be hedged by the utility. The operating norms should be 'normative' and should not be lower of normative and actual. The norms should be attainable, but must reflect technological changes, fuel, vintage of asset and operating conditions etc. CERC would notify these norms for generation and transmission and the same would be adopted by SERCs. SERCs may however, fix a relaxed norm in case where operations have been at a lower level but may also draw a transition path towards norms specified by the CERC. Operating norms for the distribution networks would be specified by the respective SERC.

The policy, in line with the Act, specifies that from April 1, 2006 all tariffs would be under MYT (multi-year tariff) framework and should feature 3-5 year control period. Once the revenue requirements have been fixed, the ERCs should focus on regulation of outputs and not the input costs. It also discourages creation of regulatory assets implicitly by emphasising on recovery of uncontrollable costs speedily so as not to burden future consumers with past costs. The benefits from CDM (clean development mechanism) should be factored in while fixing the tariff as per the policy but should provide adequate incentive for such development. The policy document underscores the need for State Governments not to impose duties, levies and taxes on selective basis including captive generators so as not to distort competition and also to keep these at reasonable levels so that tariffs remain reasonable.

On Generation Tariff

The policy specifies that the two-part tariff structure should be adopted for all long-term contracts to facilitate merit order dispatch. The ERCs should have time-varying (peak vs. non-peak) fixed charges for better load management. The PPAs should have adequate and bankable payment security mechanisms and in case of persistent default, the generator should be free to sell outside the PPA. In case of coal-based generation, the cost of project may also include reasonable cost of coal beneficiation, coal washeries and dry ash handling and disposal system. The captive generators on the grid should have same terms as other generating stations subject to ABT or should be paid actual variable cost and a reasonable capacity

charge, which may be different for peak and non-peak hours. Wheeling charges for such generators should be known in advance as declared by the SERC. On non-conventional sources of energy generation, the tariff policy specifies that the SERCs should fix the percentage of share of power to be procured on a competitive basis (within the same type of source of energy) by the distribution licensees by April 1, 2006. Such procurement may have to be at a differentiated (higher) price. CERC should within three month lay down the guidelines for procurement of such power on non-firm basis.

On Transmission Tariff

The policy document recognizes that the national grid in the country is under development, that the development of state networks has not been uniform and that there is a need to develop the network at all levels by attracting investments. The CERC should develop a national tariff framework, in consultation with the CEA, for transmission tariffs, which are sensitive to quantum, direction and distance of flows. This could be based on zonal postage stamp pricing or MW-mile basis or some other variant based on the principle of system users sharing their respective share of utilization of the network. It should not inhibit development of the network but should also not encourage non-optimal investments. In line with the Electricity Policy, the Tariff policy also states that the network expansion would not be based on prior agreement with the beneficiaries and the CTU/STUs can undertake investments in line with the National Plan and in consultation with stakeholders. CERC within one year would specify the norms of capital and operating costs for transmission lines at various voltage levels based on baseline studies commissioned by the CERC. Investment by others (other than CTU/STU) in transmission would be on competitive bid basis for which the Central Government would come out with the guidelines. The tariffs of the projects to be done by the CTU/STU would also be based on competitive basis after five years or whenever ERCs are satisfied that this can be done. Once CERC specifies transmission tariff framework, the SERCs would also use it for intra-state transmission network within two years. Metering on the network should be compatible with the tariff and ABT framework including TOD metering. The policy specifies that the transactions on the network should be charged based on average loss after considering the distance and directional sensitivity as applicable at the relevant voltage level. CERC should evolve such a methodology for inter-state transmission which can be used by FOR to evolve a similar approach for intra-state transmission. The loss compensation should be reasonable and should be established by the ERCs in consultation with the CEA. In order to assess the need for network expansion and investments, necessary studies may be carried out by ERCs and such capex may be allowed to prevent overloading of lines. There is also a need for ERCs to create financial incentives and disincentives for CTU/STUs based on their key performance indicators (KPIs). These should include network construction, system availability and loss reduction. The

CTU/STUs/RLDCs/SLDCs should also make available information on available transmission capacity and load flow studies to intending users.

On Distribution Tariff

The Tariff Policy underscores the need for the distribution segment of the sector to become solvent and efficient for the realization of full potential of the development of the sector. The ERCs therefore need to strike a balance between commercial viability of the distribution licensees and consumer interests. Loss making utilities need to be transformed into profitable ones and efficiency in operations need to be encouraged by sharing the efficiency gains between consumers and licensees through MYT framework specified in the Act. This would also minimize regulatory risks and attract investments. The SERCs should introduce mechanism of sharing gains and losses within overall MYT framework which could be asymmetric for the first control period with more gains accruing to the utility than the losses vis-à-vis consumers. The MYT framework in the first control period should have flexibility to accommodate changes in the baseline estimates consequent to 100% metering. In the first control period, the uncovered gap between required tariffs and current tariffs need to be covered either by tariff increases or financial restructuring and transition financing. The licensee would have the flexibility to charge less than the regulated tariffs and file for an area separately when the area has a competing licensee. The SERC should initiate tariff determination, *suo moto*, in case the filing has not been made by the licensee. Any revenue gap due to filing would be on account of the licensee.

While determining the revenue requirements and costs, all power purchase costs would be considered legitimate unless it has been purchased at an unreasonable cost or merit order has been violated. Reduction in AT&C losses should not be achieved by denying revenues for power purchase for 24 hours supply, and reasonable O&M costs and capex. Actual retail sales should be grossed up based on normative T&D losses for allowing power purchase costs subject to justifiable purchase mix and fuel surcharge. The MYT trajectory should be attainable and should create political will for theft reduction by allowing full cost recovery. To deter theft and create social pressures, SERCs may impose area/locality specific surcharge based on AT&C losses. SERCs may also encourage area based incentives and disincentives for the local staff. The baseline independent assessment for various parameters of each circle should be undertaken by SERCS and be completed by March 2007. Metering should also be completed by the same time and then it should be possible to segregate technical losses, which should be treated differently from commercial losses in the MYT trajectory. In line with Section 65 of the Act, the SERCs should fix the tariffs without considering subsidies from the State Government and it should lower only if the Government pays for it.

SERCs should allow working capital related to past recoveries. Similarly past losses and profits due to uncontrollable factors should be allowed. During the transition, controllable factors should be to the account of utility and consumers as specified in the MYT framework. The practice of creation of regulatory asset should not be freely resorted and should be done only as an exception under force majeure conditions as specified in the regulations. In such cases also, the recovery should be time bound and till such time carrying cost should be allowed to the utility. SERCs should also ensure that such regulatory assets do not depress return on equity to very low levels.

On Distribution Tariff and Cost of Service

The Tariff Policy recommends that the State Government should targeted direct subsidies, than cross-subsidies, for the purpose as spelt out in section 65 of the Act. Only consumers belonging to BPL category may be given special support to the extent of 50% for 30 units a month in line with the National Electricity Policy. This provision may be re-examined after 5 years. The SERCs should notify the roadmap within six months the target latest by 2010-11 for brining tariffs to within +/- 20% of average cost of supply. For agricultural tariffs, the tariffs should also factor in the sustainable exploitation of ground water resources and should be different in different parts of the state depending upon sustainability of ground water use. The policy also recognizes the need to provide higher subsidies to poor farmers in adverse ground water table condition, which is somewhat contradictory! For every category, the document stresses on the need for recovery of reasonable user charges. Subsidized rates should be permitted only up to a pre-identified level beyond which cost of service should be recovered. The document also stresses on metering for all consumers.

On Cross-subsidy Surcharge and Additional Surcharge for Open Access

The Tariff Policy document specifies that the cross-subsidy surcharge would be the difference between- (i) the tariff applicable to the relevant category of consumer, and (ii) the cost of the licensee to supply to that category of consumer. The cost of the supply may be computed as- (a) the weighted average of the cost of power purchase of the most expensive 5% at the margin, excluding liquid fuel based generation, in the merit order (including system losses), and (b) the distribution charges determined by the SERC on the principles laid down for intra-state transmission charges. SERCs should bring down the cross-subsidy to +/- 20% in a linear manner by 2010-11. The additional surcharge as per section 42(4) would be leviable only in case it is demonstrated that the power purchase commitments of the licensee would get stranded and/or there is a fixed obligation on any such contract. Wheeling charges for the open access consumers would be based on principles of intra-state transmission and would take into account losses at the

relevant voltage levels. The standby arrangements would be provided by the licensee at temporary connection charges to be determined by the SERC.

The Tariff Policy also notes that the ERCs need to monitor trading transactions to ensure that traders do not indulge in profiteering in situation of shortages. ERCs may fix margins for achieving this objective.

3.12 Tariff-based Procurement of Power: Guidelines for Competitive Bidding

As envisaged in section 63 of the Electricity Act, the Central Government issued guidelines for procurement of power on medium to long-term basis by the distribution licensees and notified in January 2005. The guidelines were amended on 30th March 2006, 18th August 2006 and 27th September 2007. The competitive procurement of power from generators is premised on the fact and assumption that competition is expected to bring down the power purchase costs, which constitute a major fraction of the overall cost of supply. The guidelines have the following objectives:

- Promotion of competitive procurement of electricity by distribution licensees;
- Facilitating transparency and fairness in procurement process;
- Facilitating reduction of information asymmetry across bidders;
- Protection of consumer interest by creating conditions for competition;
- Enhancing standardization and reduction of ambiguity for the bidders;
- Providing flexibility to suppliers while ensuring certainty to buyers.

Applicability and Types of Procurement

These guidelines are applicable for long-term procurement i.e. above 7 years and for medium term procurement i.e. exceeding one year but less than 7 years. The guidelines cover two possible cases- (1) where the location, technology and fuel has not been specified by the procurer (distribution company or its agent) called Case 1, and (2) where the procurement is for hydro-power, load centre projects or other location specific projects with specific fuel allocation such as captive mines, which the procurer intend to set up under tariff based bidding process called Case 2. Two or more procurers can jointly do the procurement through an authorized agent or through a SPV in case of 2 projects.

Preparation for Inviting Bids

All procurers need to follow these guidelines and any deviation has to have the approval of the ERC, which has to be taken in 90 days. ERC approval has to be taken in case the quantum of energy being procured is more than projected demand

forecast in next three years, as per Electric Power Survey of the CEA or in case the fuel price is not specified by or regulated by the Government or Government approved mechanism for Case 2 procurement. For Case 2 projects, the following must be obtained before inviting bids- (i) Site identification and notification for land acquisition, (ii) environmental clearance, (iii) forest clearance, (iv) fuel arrangements, (v) water linkage, and (vi) acquisition of hydrological, geological, meteorological and seismological data for preparation of DPR. The bidder would be free to verify the geological data as the geological risk would be with the bidder. On the other hand, according to the guidelines, the hydrological risk in case of hydro - power (in Case 1 as well as Case 2) would be with the procurer provided hydrological data is known to both the parties and has been obtained from reliable sources. The price of the project site would be intimated to the bidders 15 days ahead of submission of RFP bids. It is recommended, but not mandatory, that the procurer obtains transmission clearances for receiving power at delivery points prior to inviting bids. Otherwise, it will be responsibility of the successful bidder.

Tariff Structure

The guidelines specify that the tariff under competitive procurement shall be paid and settled every period, which is not to exceed one month. The bids would have multi-part tariff structure featuring capacity and energy component separately. However, for medium term procurement the procurer can invite bids on a single part tariff, to be mentioned clearly in RFQ/RFP documents. In case combined capacity and energy charges are quoted, no escalation would be allowed and the charges would be payable based on rates quoted for the year. In such cases, the bidder shall indicate the normative availability and quoted per kWh rate would be applicable beyond the normative level of availability but the RFQ/RFP shall have feature of penalty below the normative level availability. Procurement for Case 2 would have multi-part tariff structure. In case of long-term procurement with specific fuel allocation (one instance of Case 2), the bids would be in terms of capacity charge and net (quoted) heat rate. The net heat rate would be on ex-bus basis taking into account internal consumption and the energy charges would be paid for as under-

Energy Charge = Net quoted heat rate x Scheduled generation x Monthly weighted average price of fuel / Monthly average gross calorific value of fuel

The ERC would have to approve the fuel prices if it is not approved by the Government or Government approved mechanism such as Energy Regulator(s). The cost of secondary oil should be factored in capacity charges by the bidders. All tariffs should be in Indian Rupees and any forex risk should be hedged or borne by the supplier/bidder. In case of imported fuel, the forex variation would be permitted in energy charges for fuel prices in case the procurer mandates use of imported fuel. In such cases (another instance of Case 2 procurement), the bids

should have three components, each having non-escalable and escalable sub-components- (a) Imported fuel component in US\$/unit, (b) Transportation of fuel component in US\$/unit, and (c) inland fuel handling component in INR/unit. These would be allowed to be escalated as per the indices specified in the RFP. Bidders can quote firm charges for each component in Case 2 procurement. In such a case, no escalation would be allowed. Transmission charges have to be borne by the procurer in all cases.

The capacity charge, according to the guidelines, shall be paid based on availability in kWh, as quoted in Rs./kWh and shall be limited to normative availability. The normative availability shall be higher by a maximum of 5% than the level specified by the CERC in its regulations and shall be computed on annual basis. The capacity charge would have two components-(a) fixed, and (b) escalable. The latter would be escalated on the basis of WPI, CPI or a combination on the base year as specified in the RFP document. Capacity charges for availability beyond normative level shall be a pre-specified %age of non-escalable component of capacity charges and shall be limited to 40% of the same at max. The procurer would have first right of refusal on energy for availability beyond normative availability level. In case availability is less than normative level, the capacity charges shall not be payable for the shortfall and if it falls below normative level to a pre-specified level, penalty @20% of capacity charge shall be applicable. The supplier shall declare availability on a daily basis as per the Grid code and if the procurer does not avail the declared availability, the same can be sold in market with gains in excess of energy charge to be equally shared between the procurer and supplier. At the bid evaluation stage, the ratio of minimum and maximum capacity charge shall not be less than 0.7 to avoid front and back loading. In case peak load or seasonal requirements are distinct from base load requirements, the bidder shall indicate distinct prices for such peak load or seasonal supply which will be evaluated separately. Such differential rates would not be violation of guidelines. The procurer(s) would create adequate payment in the form of LC or LC backed by escrow mechanism and in case supplier does not receive payment by due date, he may encash LC to the extent of shortfall and the procurer should restore payment security by the next date of payment. Failure to realize payment despite security mechanism would be event of payment default and after giving 7 days notice, the supplier can sell up to 25% of contracted power to other without losing claim on capacity charge. If the payment security mechanism is not restored within 30 days of payment default, the supplier can sell entire contracted power to others without losing claim on capacity charge. The surplus over energy charge realized by the supplier shall be adjusted against capacity charge otherwise payable by the procurer and the any excess still left would be retained by the supplier.

Energy charges, as per the guidelines, shall be related to the base energy charges which would be escalated based on the index used in the evaluation of bid

for Case 2 procurement except for captive fuel source cases, for imported fuel cases, and for cases where bid is on net heat rate as mentioned earlier. The fuel escalation index shall be specified in the RFP and the fuel escalation for fuel produced in the country would be based on Government approved mechanism.

In case of captive fuel source, the energy charges would have escalable and non-escalable component and the ratio of minimum and maximum charge during the contract shall not be less than 0.5 and the index for escalable component would be specified by the CERC. In no case, would adjustment be provided for heat rate degradation. The CERC would notify the following every six months:

- Escalation rate for domestic coal (separately for evaluation and payment)
- Escalation rate for domestic gas (separately for evaluation and payment)
- Escalation rate for different sub-components of energy charge for imported coal(separately for evaluation and payment)
- Escalation rate for different sub-components of energy charge for imported gas(separately for evaluation and payment)
- Inflation rate to be applied to indexed capacity charge
- Inflation rate to be applied to indexed energy charge for captive fuel source based plants
- Discount rate for bid evaluation
- US\$-INR exchange variation rate for evaluation

Bidding Process and Evaluation

The guidelines specify that all long-term procurement should be based on two stages bidding process featuring RFQ and RFP. However, medium term procurement could have bidding process in which both can be combined. International Competitive Bidding is necessary and the minimum condition to be met by the bidder would be specified in RFQ. The procurer will only provide written explanation to queries and the same would be made available to all bidders. Guidelines specify the standard documentation for RFQ including definition of procurer's requirements such as quantum of power (base load, seasonal and peak), term of contract, normative availability, definition of peak and non-peak hours, expected date of commencement of supply, point of delivery, construction milestones, and financial requirements. The RFQ would also include the model PPA to be entered into, which should include risk allocation, technical requirement, assured offtake levels, force majeure clauses, lead time for scheduling, default conditions and payment security proposed. It should also specify period of validity of offer, requirement of transfer of asset at the end of PPA (if any), other technical, operational and safety criteria to be met by the bidder. The procurer may also insist on demonstration of financial commitment and may create exit option for the procurer or the supplier in the PPA subject to new party taking all obligations of

the PPA. A minimum of 45 days would be allowed for submission of responses to RFQ.

Those bidders who are qualified based on RFQ submissions would be issued RFP document. Any deviation sought by the bidders and agreed upon by the procurer need to be cleared by the ERC. All deviations and revisions would be notified to all bidders and the PPA would be on the website of the procurer. The procurer would allow two months for submission of bid in case of revisions in the documents at RFP stage. RFP document would be standard and would have structure of tariffs to be submitted by the bidders, PPA to be entered, payment security mechanism, bid evaluation methodology and the maximum period after which the supply should commence including LD for delays. The maximum period for commencement of supply once PPA becomes effective shall not be less than 4 years for long-term procurement contracts. A minimum of 150 days would be allowed for submission of RFP bid from the date of issue of RFP. Eligible bidders would be required to submit technical and price bids separately. Bids shall be evaluated by a committee formed by the procurer with one external member who is not affiliated to the bidders. The technical bids would be scored and price bids of only those bids which meet all elements of minimum technical criteria would be considered. Procurement process would be carried on if number of qualified bidders is more than two. Otherwise, ERC's approval would be required for the procurer to move ahead with the procurement. Bidders can form consortium for bidding and in such event should identify a lead member with whom the procurer would communicate. The procurer would ask for a reasonable bid-guarantee and the bids would be opened in public and in front of bidders interested in being present. The price bids would be rejected if it deviates from tender conditions. In case of Case 1 procurement the bidders can quote either ex generating station bus or at delivery point. The bids would be standardized by including normative transmission charges based on prevailing CERC orders for ex bus bids.

Bids would be evaluated on the basis of composite levelled tariff computed from the submitted bids. The escalable components would be escalated based on the projected index rates declared by the CERC and the tariff so projected would be discounted at a discount rate declared by the CERC to arrive at the composite tariff. CERC would declare these rates 7 days prior to the bid deadline. The bidder with the lowest levelled tariff would be declared successful bidder and LoI would be issued to such bidder. The details of the tariffs quoted by all the bidders (without revealing their names except that of the winning bidder) and the finalized PPA after signing of PPA would be made public in the interest of transparency.

3.13 Tariff-based Competitive Bidding for Transmission Service

Like competitive bidding for procurement of power, the Central Government came out with guidelines for competitive procurement of transmission service under enabling provision of section 63 in the Act. The objectives of these guidelines are- (i) competitive procurement of transmission services, (ii) to encourage investment in transmission line by private sector, (iii) to facilitate transparency and fairness in procurement processes, (iv) to reduce information asymmetries across bidders, (v) to protect consumer interest by introducing competition for transmission services, (vi) to enhance standardization and reduce ambiguity and hence timely completion of projects, and (vii) to ensure compliance with standards, norms and codes for transmission while retaining flexibility of operations.

The guidelines state that the transmission services include execution of the project as specified by the procurer and their maintenance and operation to make the transmission system under the procurement available as per the availability norms specified by the regulators. The winner after the bid shall seek license in case it is not and will become transmission service provider after obtaining transmission license. The conditions for obtaining license from the regulators will be specified in the bid documents and so would be the technical, operational and safety criteria including the grid code and standards and regulations. Bid documents would also specify the draft of proposed transmission service agreement (TSA) which the winner would have to enter into with the concerned utilities after it becomes TSP. After becoming licensee and having entered into TSA, the TSP will undertake the project as per the specifications and timelines specified in the bid document. TSP will be liable for liquidated damages for delays, as per the bid documents and also for revocation of license if it fails to meet availability norms of regulators persistently (more than consecutive six months).

The procurement would be carried out by a Bid Process Coordinator (BPC), which will be an organization nominated by the concerned government (Union Government for inter-state and State Government for intra-state). The cost of organising bidding by BPC would be recovered from the bidder and would be stated in the bid document. BPC can either use standard bidding document notified by the Central Government or may use any other document provided it has been approved by the concerned regulator. In any case, it will inform the regulator on the start of bidding process. BPC would also facilitate the transfer of the project to the winner and also in obtaining right of way for transmission lines. The bidding process can be either two stage process having RFQ/RFP in succession or a combined two envelope RFQ/RFP processes. At the RFQ stage, bidders have to meet the financial and other technical requirements and only those whose qualify, their bids would be opened at RFP stage. BPC would also specify the criteria for reasonableness of charges and if no bid is reasonable, it will reject all the bids. BPC may call bidders conference to provide clarifications sought and the clarifications

would be provided to all bidders who qualify after RFQ stage. The TSA can also be amended by BPC at this stage based on inputs from bidders and made available to all but once the RFP stage is entered, it will be not changed.

The bids are to be based on two parts, one scalable and the other non-scalable. The scalable part of the bid not be more than 15% of non-scalable part. The bid for annual tariff consisting of both parts can be different across years but the variation should not be more than 10% in consecutive years. The bids would be in Indian Rupees and the payment would be made to the TSP based on quoted bid on monthly basis by dividing the annual quoted charge by 12. The bids will be evaluated by a committee constituted by the BPC based on bid evaluation criteria and discount factor specified in the bid document provided there are at least two qualified bidders.

3.14 Ultra-Mega Power Projects: Attracting Private Sector

In order to augment generation capacity quickly through competitive bidding route and to exploit economies of scale and technological efficiencies, the development of Ultra Mega Power Projects (UMPPs) has been a major initiative undertaken by the Central Government in consultation with various State Governments. These projects are large sized with a thermal capacity of around 4000 MW each involving investment of approx. Rs. 16000 crore. The projects have to use super critical technology, would have flexibility in selecting size of the units, would be based on either captive coal block or imported coal (at coast) and the developer of the project would be chosen based on a competitive bid under procurement guidelines. Prior to bidding of the projects, an SPV created with the support of interested procurers (States or distribution licensees) would prepare the project report, undertake EIA, prepare bidding documents, PPA etc., acquire land, coal blocks, clearance for water, pollution control board etc. In other words, some of the risks faced by a developer in a project of this kind would be mitigated by the time of bidding process. The Central Government would facilitate the process for which the Power Finance Corporation (PFC) has been identified as the nodal agency. Once the background work has been done and clearances obtained, the winning bidder would acquire the SPV and the winning bid would be based on lowest levelled tariff quoted. A total of 9 such projects, 4 at pithead and 5 coastal have been identified and 3 have been already bid for.

3.15 RGGVY: Thrust on Rural Electrification and Improving Quality of Supply to Rural Areas

In an initiative to meet the national policy objective of providing connection to all households in five years and to improve the quality of supply to rural areas, RGGVY (Rajiv Gandhi Grameen Vidyutikaran Yojana) was launched with an outlay of capital subsidy of Rs. 16000 crore to states for improving the infrastructure for rural supply. The scheme, through REC, provides for ninety percent of the capital cost of projects for:

- (i) Rural Electricity Distribution Backbone (REDB) with one 33/11 kV substation in each block,
- (ii) Village Electrification Infrastructure with one distribution transformer for each village, and
- (iii) Decentralized Distributed Generation where supply from grid is not feasible or cost effective.

The initiative recognized that so far the rural electrification was driven because of agricultural pump sets and hence the supply quality has been poor. It aims at providing 24 hours supply similar to urban areas. It also lays emphasis on need for collecting revenues and reducing the cost of supply for the initiative to sustain. It also suggests that franchisees such as NGOs, consumers associations etc. may be used effectively.

4.0 Envisaged Roles of Key Players

4.1 Central Government

The Central Government, under the Electricity Act 2003, has been vested with several critical roles. The main roles for the Central Government as per the Act are related to constitution of the apex regulatory body, load dispatch centres at national and regional level and in laying out National Electricity and Tariff Policy. These important roles are-

1. Formulation of National Electricity Plan and Tariff Policy in consultation with State Governments and the CEA (Section 3) and to review/revise them periodically.
2. Formulation of National Policy on standalone systems for rural areas including those based on renewable and non-conventional sources of energy (Section 4).

3. Formulation of National Policy on rural electrification and local electricity distribution in consultation with state governments and state regulatory commissions (Section 5).
4. Endeavouring, along with state governments, to provide electricity to rural areas and households (Section 6).
5. Establishment of National and Regional Load Dispatch centres (Section 26(1) and 27(1)).
6. To notify a government company as Central Transmission Utility and to vest part of it to any company as a transmission licensee (Section 38).
7. Appointment of Members and Chairperson of the CEA (Section 70(2) and Section 70(4), their terms and condition of service (70(15)), their continuation (70(6)) and the power to give directions to the CEA (Section 73 and 75).
8. Appointment of Members and Chairperson of the CERC (Section 76(6)) on the recommendation of Selection Committee and the terms and condition of their employment. Approval of number of employees of the CERC and their terms and conditions of employment (Section 89, 91(2), 91(3)). Establishment of CERC fund for expenses of CERC and specifying the manner of applying the fund in consultation with CAG (Section 99).
9. Appointment of Members and Chairperson of the Appellate Tribunal (Section 113) on the recommendation of Selection Committee and Chief Justice of India respectively and the terms and condition of their employment (Section 115). Approval of number of employees of the Appellate Tribunal and their terms and conditions of employment (Section 119).

Besides these, some of the other important roles and responsibilities of the Central Government, envisaged in the act, are-

- Setting the limit of capital expenditure for hydro-generating stations/projects above for which concurrence of CEA is required (Section 8(1)).
- Directing Generation Companies in extraordinary circumstances such as threat to security (Section 11(1)).
- Demarcation of regions for transmission (Section 25).
- Directions to RLDCs for stable transmission of electricity (Section 37).
- Make available grants and loans available to CERC after due appropriation made by the Parliament (Section 98).
- Direction to the CERC in matters of policy involving public interest (Section 107).
- Appointment of a Chief Electricity Inspector (Section 162) who is empowered as being equal to a civil court to conduct inquiry on accidents and to ensure safety (Section 161).

- Constitution of a Coordination Forum of CERC, CEA and entities involved in inter-state transmission of electricity for coordinated and smooth development of the sector (Section 166(1)), Constitution of Forum of Regulators consisting of Chair, CERC and Chair, SERCs (Section 166(2)).

4.2 State Governments

The State Governments, under the Electricity Act 2003, have been vested with several critical roles. Historically, electricity distribution has been the preserve of the State Government within the boundaries of the state and hence their role is extremely important as the revenue for the sector as a whole and the commercial viability of the sector is critically dependent on the support of and role played by the State Governments. One of the most important roles envisaged in the Act for the State Government is covered in part XIII of the act under “Reorganization of Board”. Under sections 131 to 134, the State Government is required to restructure the existing State Electricity Board into a State Transmission Utility, Generating Companies, Transmission and Distribution Licensees. It is also expected to constitute the SERC and Special Courts for theft cases. Some of the other roles and responsibilities of the State Government envisaged in the Electricity Act are:

- Providing inputs to the Central Government on the National Electricity Policy and Tariff Policy (Section 3(1) & 3(3)).
- Endeavouring, along with the Central Government, to provide electricity to rural areas and households (Section 6).
- Providing inputs to the CEA and ensuring co-ordination for optimal utilization of river resources in case of hydro-generation stations and multi-purpose projects (Section 8).
- Directing Generation Companies in extraordinary circumstances such as threat to security (Section 11(1)).
- Establishment of State Load Dispatch centre (Section 31).
- Directions to SLDC for stable transmission of electricity (Section 37).
- Grant of subsidy to any set of consumers should it decide so but only if it pays in the manner specified by the SERC , notwithstanding directions under section 108 (Section 65).
- Making rules and procedures for carrying out works by the licensees (Section 67(2) & 68).
- Constitute SERC or a Joint Commission with other states and appoint Chairperson and Members of the SERC on the recommendation of a selection Committee (Section 82 & 83) and the terms and condition of their employment. Approval of number of employees of the SERC and their terms and conditions of employment (Section 89, 91(2), 91(3)). Establishment of SERC fund for expenses of SERC and specifying the manner of applying the fund in consultation with CAG (Section 103).

- Make available grants and loans to SERC after due appropriation made by the Legislature (Section 102).
- Direction to the SERC in matters of policy involving public interest (Section 108).
- Designating Assessing Officer for detection of unauthorized use of electricity (Section 126).
- Authorizing any officer for powers to detect, search, seize and act in cases of theft of electricity (Section 135(2)).
- To appoint Special Courts for speedy trial of cases related to theft and unauthorized use of electricity and other offences specified under sections 135-140 & 150 (Section 153).
- Appointment of an Electricity Inspector (Section 162) who is empowered to conduct inquiry on accidents and to ensure safety (Section 161).
- Constitution of a Coordination Forum of SERC and entities involved in the sector within the state for coordinated and smooth development of the sector (Section 166(3)).
- Constitution of a Committee in each district for electrification, quality of supply, energy efficiency and conservation (Section 166(4)).

4.3 CERC

The Central Electricity Regulatory Commission (CERC), as the apex regulatory body, under the Electricity Act 2003, has been vested with several critical roles as an independent regulator in a sector, which is envisaged as open for private participation in the Electricity Act 2003. With the reforms undertaken by several States in the nineties, the need for an independent regulator was felt in the sector for the first time and those states created their own regulatory bodies with enactment of state level laws. Later, a central statute was enacted in 1998 which allowed a common legal framework for regulation in the sector and resulted in creation of CERC, whose jurisdiction was limited to the entities covering more than one state. The Electricity Act 2003, as a comprehensive statute, replaced the earlier act and clarified and extended role of CERC. The main functions spelt out in the Section 79 of the Act, for the CERC are:

- To regulate the tariffs of Central Government owned generating companies.
- To regulate the tariffs of generating companies supplying to more than one state.
- To regulate inter-state transmission and to determine inter-state transmission tariffs.
- To issue licence to traders and transmission licensees for inter-state operations.
- To adjudicate disputes involving generating companies and transmission licensee on the above matters and to refer disputes for arbitration.

- To specify Grid Code in sync with Grid Standards.
- To specify standards of quality, continuity and reliability of service to be provided by licensees.
- To fix the trading margin in case of inter-state trading if necessary.
- To fix the fee and levy charges for the above functions and to perform them in a transparent manner within the framework of National Electricity Policy, Plan and Tariff Policy.
- To advise the Central Government on National Electricity and Tariff Policy and on promoting investment, competition, efficiency and economy in the sector.

Besides these, some of the important roles and responsibilities of the CERC envisaged in the Electricity Act and spelt out in other sections, are:

- Final adjudication of availability of transmission capacity with Central Transmission Utility for open access for Captive Generation Plants (Section 9(2)).
- Granting licence to an entity for transmission, and trading of electricity without which no one is allowed to undertake these activities (Section 12-15) save the entities exempt in Section 13 &14.
- Specifying the terms and conditions of a licence, revising them and revoking a licence if public interest so requires (Section 16-24).
- Resolving dispute on directions given by RLDCs (Section 29(5)).
- To allow the use of inter-state transmission lines owned and operated by one licensee by another subject to surplus capacity and payment of charges to be specified by the CERC (Section 35, 36).
- Specifying requirements for inter-state trading licence and terms and conditions (Section 52)
- Specifying the manner in which default on metering, as specified by the CEA, has to be made good by the entity responsible for default in its jurisdiction (Section 55(3)).
- To specify the standards of performance for protecting consumer interest for various class of consumers and licensees, to collect information on the same and to levy penalty in case of violation (Section 57, 58 & 59).
- To direct licensees and other entities in case of likely abuse of dominant position for inhibiting competition (Section 60).
- Determination of tariffs in line with National Electricity Policy with the objectives of- recovery of cost of supply, commercial principles, encouraging efficiency and rewarding efficiency gains, multi-year tariff principles, promoting co-generation and from renewable sources of energy, and phased elimination of cross-subsidies (Section 61).
- Unless tariffs are determined by the bidding process according to guidelines issued by the Central Government (Section 63), CERC to determine the tariff for generating company supplying to a distribution licensee (including max. and min. price for short-term contracts), transmission, and to collect such details as

may be required from the entities (Section 62). To issue tariff orders on applications made within 120 days after public hearings (Section 64).

- To promote development of market and trading as may be specified by the Central Government through National Policy (Section 66).
- Creation of a Central Advisory Committee headed by Chair, CERC for advising the CERC on matter of policy, quality of service, compliance by licensees and requirements of licensees, protection of consumer interest, performance standards etc (Section 80 & 81).
- Power to enforce as a Civil Court (Section 94-96) on calling persons, public record, accepting affidavits, evidence collection, examination of witness etc.
- Maintenance of accounts of CERC fund as specified by the Central Government in consultation with CAG, getting them certified by the CAG and submitting it to the Government for tabling the same in the Parliament (Section 100).
- Preparing annual report of its activities and submitting it to the Central Government (Section 101).
- Preparing budget for the ensuing year and forwarding it to the Government (Section 106).
- To direct any person as investigating officer to investigate the affairs of any entity in its jurisdiction should it be satisfied that the entity has not complied with the act or the regulations, to consider the report of the officer and to suggest remedial action or to cancel licence or to order ceasing generation after giving opportunity to the entity (Section 128-130).
- Power to impose penalty of up to Rs. 1 lakh for each contravention of act or regulations by any person after giving due opportunity to be heard (Section 142).
- Appointment of any of its members as an adjudicating officer who will have power to summon and enforce the attendance of any person for facilitating inquiry (section 143).

4.4 Appellate Tribunal

In the Electricity Act 2003, the appellate tribunal is the apex judicial body envisaged to appeal against any decision of any adjudicating officer or the regulatory commission. Any appeals against the appellate tribunal's order can be made within 60 days in the Supreme Court (Section 125). The powers of the appellate tribunal under the Act are specified as under:

- To entertain any appeal made by an aggrieved party, to call for records of proceedings by any order against which appeal has been filed, and to issue an order on the appeal within 180 days (Section 111).
- The tribunal has the power of a civil court and its orders are executable as decree of a civil court. However, the tribunal would not be governed by the

code of civil procedure, 1908 but by principles of natural justice. The proceedings of the tribunal would be considered judicial proceedings (Section 120).

- The chairperson of the tribunal shall exercise general power of superintendence over ERCs (Section 121).

4.5 CEA

The Central Electricity Authority (CEA), historically, has been an apex level body assisting the Ministry of Power at the central level for planning and policy formulation. It has been also an agency involved in development of capability and technology at the national level and for coordination across states wherever required such as for transmission planning etc. Earlier, CEA was also responsible for techno-economic clearance of all generation projects. This role was taken away from CEA prior to enactment of the act save for Hydro generation projects. Some of the important roles and responsibilities of the CEA envisaged in the Electricity Act are:

- Preparation and revision of National Electricity Plans every five years in accordance with National Electricity Policy (Section 3(4) & 3(5)) after taking inputs from entities in the sector and the public.
- Concurrence to any scheme submitted for hydro-generating station, entailing capital expenditure above a certain sum, keeping in mind the best possible development of river resources in consultation with central and state governments, design and safety norms (Section 8).
- To prepare Grid Standards, which specify technical standards of operation and maintenance of transmission lines to be complied by all transmission licensees (Section 34).
- To specify in consultation with the State Government, suitable measures for safety of public, property and injury, fixing standards and specifications (Section 53).
- To specify the meters required for supply (Section 55(1)) and to specify metering requirements for licensees and generating companies, wherever required (Section 55(2)).
- To advise the Central Government on National Electricity Policy and to formulate plans and to coordinate with planning agencies for optimum development of the sector with a view to provide affordable and reliable electricity (Section 73(a))
- To specify technical standards, safety requirements, Grid Standard, condition for installation of meters and to promote and assist in timely completion of projects and schemes in the sector (Section 73 (b)-73(f)).
- To collect (Section 74) and disseminate information related to the sector, to advise entities in the sector, to develop capability and to promote research in the sector (Section 73(g)-(o)).

4.6 SERCs

The State Electricity Regulatory Commissions (SERCs), as the state level regulatory bodies, under the Electricity Act 2003, has been vested with several critical roles as an independent regulator. As mentioned earlier, some of the SERCs were created by the states, which initiated private participation in the sector. With the Electricity Act 2003, the role of SERCs has been clarified in the comprehensive statute, replacing the state level acts and the earlier act enacted in 1998. The main functions spelt out in the Section 86 of the Act, for the SERCs are-

- To determine the tariffs of generation, supply, transmission and wheeling of electricity whether bulk or retail within the state except for determination of wheeling (and surcharge thereon, if any) for open access category consumers.
- To regulate electricity purchase and procurement process of the distribution licensees including the price at which electricity would be procured.
- To facilitate intra-state transmission and wheeling of electricity.
- To issue licence to distribution licensees, traders and transmission licensees for intra-state operations.
- To promote cogeneration and generation from renewable sources of energy.
- To adjudicate disputes involving generating companies and the licensees and to refer disputes for arbitration.
- To specify State Grid Code consistent with Grid Code specified by the CERC.
- To specify standards of quality, continuity and reliability of service to be provided by licensees.
- To fix the trading margin in case of intra-state trading, if necessary.
- To fix the fee and levy charges for the above functions and to perform there in a transparent manner within the framework of National Electricity Policy, Plan and Tariff Policy.
- To advise the State Government on restructuring of the sector and on promoting investment, competition, efficiency and economy in the sector and matters referred to by the Government.

Besides these, some of the important roles and responsibilities of the SERCs envisaged in the Electricity Act and spelt out in other sections, are as follows:

- Final adjudication of availability of transmission capacity with the State Transmission Utility for open access for Captive Generation Plants (Section 9(2)).
- Granting licence to an entity for transmission, distribution and trading of electricity without which no one is allowed to undertake these activities (Section 12-15) save the entities exempt in Section 13 & 14.
- Specifying the terms and conditions of a licence, revising them and revoking a licence if public interest so requires (Section 16-24).

- Facilitating and promoting transmission, wheeling and inter-connection arrangements for economic and efficient transmission and supply (Section 30).
- Resolving dispute on directions given by SLDC (Section 33(4)).
- To allow the use of intra-state transmission lines owned and operated by one licensee by another subject to surplus capacity and payment of charges to be specified by the SERC (Section 35, 36).
- To introduce open access in phases considering cross subsidies and by imposing a surcharge for open access even if subsidies are not eliminated (Section 42(2)).

In an amendment in 2007, the cross-subsidies to be “eliminated” was removed from Sections 38-40 and 42.

In an amendment to the Act in December 2003, the SERCs are expected to provide open access to consumers having more than 1 MW peak supply of electricity within 5 years.

- To impose a surcharge on wheeling charges to recover fixed charges for a distribution licensee of the area when open access (to receive supply from other sources) has been allowed for some consumers (Section 42(4)).
- To specify the period within which the distribution licensee has to provide connection in case more than one month is required for licensee (Section 43(1)).
- To fix the charges of electricity supplied by the distribution licensee (Section 45).
- To fix the charges for recovering expenses incurred in and to fix a reasonable security and interest thereon for supplying electricity for a new connection (Section 46 & 47)).
- To specify an Electric Supply Code covering recovery of electricity charges, disconnection conditions, restoration terms and conditions, tampering, billing period, entry for the licensee personnel for disconnection, replacement and maintenance of electric lines, meters and equipment (Section 50).
- To allow licensee to use its assets for other businesses for better utilization (Section 51).
- To extend the period of supplying electricity with meters beyond two years (Section 55(1)).
- Specifying requirements for trading licence and terms and conditions (Section 52)
- Specifying the manner in which default on metering has to be made good by the entity responsible for default in its jurisdiction (Section 55(3)).
- To specify the standards of performance for protecting consumer interest for various class of consumers and licensees, to collect information on the same and to levy penalty in case of violation (Section 57, 58 & 59).
- To direct licensees and other entities in case of likely abuse of dominant position for inhibiting competition (Section 60).
- Determination of tariffs in line with National Electricity Policy and using methodology specified by the CERC with the objectives of- recovery of cost of supply, commercial principles, encouraging efficiency and rewarding efficiency gains, multi-year tariff principles, promoting co-generation and from renewable sources of energy, and phased reduction and eventual elimination of cross-

subsidies (Section 61). The word elimination was later removed through an amendment to the Act.

- Unless tariffs are determined by the bidding process according to guidelines issued by the Central Government (Section 63), SERCs to determine the tariff for generating company supplying to a distribution licensee (including max. and min. price for short-term contracts), transmission, wheeling and retail sale and to collect such details as may be required from the entities (Section 62). To issue tariff orders on applications made within 120 days after public hearings (Section 64).
- To specify the manner in which the State Government's decision to grant subsidies to any consumer(s) has to be paid for by the Government (Section 65).
- To promote development of market and trading as may be specified by the Central Government through National Policy (Section 66).
- Creation of a State Advisory Committee headed by the Chair, SERC for advising the SERC on matters of policy, quality of service, compliance by licensees and requirements of licensees, protection of consumer interest, performance standards etc (Section 88 & 89).
- Power to enforce as a Civil Court (Section 94-96) on calling persons, public record, accepting affidavits, evidence collection and seizure, examination of witness etc.
- Maintenance of accounts of SERC fund as specified by the State Government in consultation with CAG, getting them certified by the CAG and submitting it to the Government for tabling the same in the Legislature (Section 104).
- Preparing annual report of its activities and submitting it to the State Government (Section 105).
- Preparing budget for the ensuing year and forwarding it to the Government (Section 106).
- To direct any person as investigating officer to investigate the affairs of any entity in its jurisdiction should it be satisfied that the entity has not complied with the act or the regulations, to consider the report of the officer and to suggest remedial action or to cancel licence or to order ceasing generation after giving opportunity to the entity (Section 128-130).
- Power to impose penalty of up to Rs. 1 lakh for each contravention of act or regulations by any person after giving due opportunity to be heard (Section 142).
- Appointment of any of its members as an adjudicating officer who will have power to summon and enforce the attendance of any person for facilitating inquiry (section 143).

4.7 CTU and STUs

One of the important necessary conditions and a critical element of introducing competition in the sector at generation or distribution /supply streams of the sector is separation of transmission and dispatch from the other sub-sectors. The Electricity Act 2003 provides for both separation of transmission as well as dispatch from the generation and distribution. These two functions have to be based on efficient operation of the system without any commercial interest of their own to provide level-playing field to competing generators on the supply side and competing distributors/suppliers on the demand side of the electricity sector. The Electricity Act envisages a Central Transmission Utility (CTU) operating inter-state transmission network and a state-specific State Transmission Utility (STU) operating intra-state transmission network. These entities have to be owned by the Government. Some of the roles and responsibilities envisaged for the CTU in the Act are as follows:

To undertake transmission through inter-state system, to coordinate and plan with state level (state governments, STUs, generating companies, regional committees, licensees) and central level entities (central government, CEA) for development of an efficient and economical network and to provide non-discriminatory open access to any licensee or generating company (or consumer, if allowed open access) on payment of charges determined by the CERC (Section 38(2)).

Similar to the CTU, some of the roles envisaged for the STUs in the Act are:

To undertake transmission through intra-state system, to coordinate and plan with state level (state governments, generating companies, regional committees, licensees) and central level entities (CTU, CEA) for development of an efficient and economical network and to provide non-discriminatory open access to any licensee or generating company (or consumer, if allowed open access) on payment of charges determined by the SERC (Section 39(2)).

Any other transmission licensee also has to perform same role as that of CTU or STUs (Section 40).

4.8 NLDC, RLDCs and SLDCs

As pointed out earlier, the Electricity Act 2003 separates transmission and dispatch from generation and distribution. To coordinate the dispatches at various levels at three distinct levels reflecting the topology of transmission networks, a three tier coordinated dispatch organization structure is envisaged. These are – National Load Dispatch Centre (NLDC), Regional Load Dispatch Centres (RLDCs), and State Load Dispatch Centres (SLDCs). These entities have to be owned by the

Government according to the Act. The roles and responsibilities envisaged for RLDCs are:

- Ensuring integrated operation of the power in their respective region in compliance with Grid Code and methodology specified by the CERC for optimum scheduling and dispatch (Section 28(1) and 28(2)).
- Being responsible for scheduling and dispatch in accordance with contracts with licensees and generating companies, for monitoring grid operations, for real time operations, for supervision and control of the system and for keeping account of quantity of electricity transmitted through the regional grid for which it may collect fees determined by the CERC(Section 28(3) and 28(4)).
- Directing the entities in the sector for ensuring stability of grid through SLDCs for compliance (Section 29).

Similar to RLDCs, the roles and responsibilities envisaged for SLDCs are:

- Ensuring integrated operation of the power in the state for optimum scheduling and dispatch (Section 32(1)).
- Being responsible for scheduling and dispatch in accordance with contracts with licensees and generating companies, for monitoring grid operations, for real time operations, for supervision and control of the system and for keeping account of quantity of electricity transmitted through the state grid for which it may collect fees determined by the SERC(Section 32(2) and 32(3)).
- Directing the entities in the sector for ensuring stability of grid for compliance (Section 33).

The Electricity Act together with various policies and guidelines issued by the Central Government provide the framework for development of the sector and to continue reform measures, which have been initiated in last decade or so. The roles and responsibilities, as discussed above, are fairly clearly spelt-out in the Act itself and wherever required have been clarified through various policies and guidelines at a later date. The next section of the report reviews the progress on implementation of various provisions of the Act and the policies. It also discusses critically the issues facing the sector. It is based on our interactions with the officials and players in the sector and also information, which is mostly in the public domain and is widely known.

5.0 Electricity Reforms: An Assessment and Issues Today

A Quick Review of Implementation of the Act by the States

There were eight states, which had already initiated reforms even prior to the enactment of the Electricity Act in 2003. These states and their reform legislations were mentioned in the schedule of the Electricity Act. The states were- (1) Orissa, (2) Haryana, (3) Andhra Pradesh, (4) Uttar Pradesh, (5) Karnataka, (6) Rajasthan, (7) Delhi, and (8) Madhya Pradesh. These states had already unbundled their SEBs, even if they had not created STUs and SLDCs, which were truly independent and had no commercial interest. Some of the transmission entities, for example, were trading as defined in the EA 2003 on behalf of their distribution utilities.

By the beginning of 2008, there were still quite a few states which had not unbundled the sector. These states were (1) Bihar, (2) Himachal Pradesh, (3) Jharkhand, (4) Kerala, (5) Meghalaya, (6) Punjab, and (7) Tamil Nadu. Most of these states have been seeking extensions to implement the provisions of the Act as far as unbundling is concerned. In addition to the above, there are states which were exempt from unbundling as per the Electricity Act. The exempt states, most of which have electricity departments rather than boards, were (1) Arunachal Pradesh, (2) Goa, (3) Jammu & Kashmir, (4) Manipur, (5) Mizoram, (6) Nagaland, and (7) Tripura. Out of these states, only Arunachal Pradesh and Nagaland have not as yet constituted their SERCs. Among the states which had constituted the SERC, most SERCs had become functional by early 2008 and had issued at least one tariff order. Some of the SERCs though constituted earlier became functional with lag, for example, Bihar and Tamil Nadu. Clearly, the progress of implementation of the provisions has been uneven across states and has ultimately depended on the readiness and willingness of the State Government to implement the Act and the reform measures. Besides uneven progress on unbundling and reorganization of SEBs, there have been other issues which have been faced by the states and entities entrusted to perform their roles in the sector. These issues are dealt with in this section of the report.

5.1 Adding and Utilizing Generating Capacity

Investment in Generation Capacities is an Important Policy Objective

In order to facilitate investments in generation capacity, the Electricity Act has freed generation from any licensing requirement or from obtaining any formal approval specifically for setting up generation capacities except in case of large hydro projects, which would use water resources of rivers. The National Electricity Policy and the National Plan lay emphasis on the need to add capacity for making

electricity accessible to all and to alleviate energy shortages in the country. The Tariff Policy provides for setting return on investment in the sector (including generation), which is similar to what the private sector can get in other sectors, adjusted for risks. All these measures and other initiatives such as procurement guidelines, UMPP and development of hydro potential etc. are aimed at adding adequate capacities in the sector including from the private sector in competition with public sector. Besides addition of capacities to meet the demand of a growing economy, it is even more important to utilize the existing capacities optimally.

Situation Today

Last two years have seen tremendous private sector response to creation of generation capacities under various initiatives and routes (i) Ultra Mega Power Project (UMPP) bidding for Sasan, Mundra and Krishnapatnam projects, (ii) Procurement bids by distribution utilities, and (iii) Creation of merchant capacities. The private sector initiatives were well supported by the buoyant capital markets, which provided risk capital in the form of IPOs and private equity to developers and promoters of such entities. In fact, "hot IPO market" of 2006 and 2007 might have also warped the incentives for the private sector to bid more aggressively may be even "irrationally" as the risks and the cost of errors could be easily passed on to the public (IPO investors). To an extent, the private sector response has been enthusiastic for UMPPs and for setting up capacities in some states, which have been ready to facilitate the process. States such as Chhattisgarh, Gujarat and Maharashtra would come in this category. Some of the enthusiastic states have been asking for free power for the state as a percentage of the capacity, which amounts to taxing the production in the state. Some other states have been less enthusiastic in allowing private or public sector to set up generation capacities despite having energy resources. Besides the lack of willingness of some states, the physical time taken in completing the projects still remains an issue with various clearances, land acquisition and associated R&R increasing the gestation period. The issues in setting up capacities are discussed below.

On capacity utilization front, while for the country as a whole and particularly for central sector/private sector generation capacity, the availability and utilization has been increasing, there are states where the state sector capacities are well below the feasible socially optimal levels even when the fuel is available. The capacity utilization of gas based and liquid fuel plants has been much below optimal levels due to non-availability of gas and high prices of gas as well as liquid fuels with almost secular rise in crude prices from 2003 to July/August 2008. The crude prices have fallen now but are still above 2003 levels. The availability of gas continues to haunt gas-based plants as they are not able to operate optimally and have had poor PLFs.

Arguments for Not Facilitating Generation Capacity Addition in the State

States such as West Bengal have not been very keen on having generation capacity within the state for use of the capacity outside the state despite having primary energy source, i.e., coal. From the point of view of the state, only the royalty and cess on the coal is available to them whether the coal is used within the state or outside. Allowing generation capacity results in land acquisition and R&R problems without any corresponding revenue or benefits. As seen by them, any small local economic benefit due to activity at the plant and its township is more than offset by local pollution and R&R costs. Some other states have used their resources advantage to bargain for free share of capacity from investors. Some have favoured private sector to public sector because it is easier to bargain for the same with private sector than public sector. There are instances of unilaterally increasing water cess on the CPSU plants and thus creating a difficult situation by the non cooperative State Governments.

Besides reluctance of the states to allow generation capacities without substantial local benefits, there are other inter-state issues as well. Some states in North East are not very keen on transmission through their states for evacuation of power as the transmission tariffs are loaded to the region where the lines are, even if the region does not require that investment. Right of way in such cases creates difficulties.

Gas Availability and Gas Utilization Policy

As on 31st March 2008, capacity of around 13000 MW gas-based generation existed in the country. Another 1100 MW capacity was ready for want of commissioning and around 1000 MW of liquid fuel capacity was capable of running on gas. All these required around 77 million standard cubic meters per day (MMSCMD) of gas supply to operate at 90% capacity utilization. As against this, only around 39 MMSCMD gas (including R-LNG) was made available to the sector. Overall supply itself was estimated to be of the order of 100 MMSCMD and despite approx. 40% supply to the sector, the gas availability was only around 50% on an average. A similar situation albeit resulting in less demand –supply gap was and is prevalent in fertilizer sector, another anchor costumer of natural gas. The maximum impact of this shortage in relation to requirement has been borne by the electricity sector. Notably it is also the largest consumer of natural gas.

The availability of gas in India has been mainly from there distinct sources- (i) the gas produced from fields operated by ONGC/OIL before NELP era, (ii) the gas from JVs and private sector under NELP, and (iii) the gas from imported LNG. The price of the first one is administered (APM gas) and its share under overall demand growth is declining. The gas from other sources is priced differently and has been high in last few years being reflective of high crude/energy prices globally. Natural gas prices world over increased dramatically in 2003-July 2008

period. The newer sources of natural gas are particularly vulnerable to changes in the international price increases. In any case, the fixed price long-term contracting in case of domestic sources is much less riskier in terms of availability at a fixed price than when such contracts are across countries. This was demonstrated when Russia stopped supplies to re-negotiate its long term contracts with buyers. Imported LNG is difficult to contract at fixed price for very long periods though Petronet has been attempting to do so. Besides price volatility of imported LNG or price of NELP gas, the availability also remains an issue at this juncture. This is especially so with allocations of 120 MMSCMD exceeding domestic supply of around 77 MMSCMD and around 26 MMSCMD of gas from imported LNG as of March 2008. Currently, the Government of India allocates the available gas and has laid down priority uses. In addition to the available gas, domestic supply of gas is expected to increase to the tune of 40 MMSCMD from early part of 2009 once the Reliance starts production from D-6 field in KG basin.

For the impending D-6 production and other NELP (or free gas as opposed to APM gas) gas, the government (EGOM) has established the priority uses for which the gas produced by private players can be sold. The priority, however, does not involve any price preference to any of the priority sectors. In this decision of May, the first priority without any quantity restriction has been given to fertilizer sector. The second priority with a cap (of 3 MMSCMD out of expected 40 MMSCMD gas from D-6) has been given to gas-based LPG plants. Power generation has been given third priority with a cap (of 18 MMSCMD out of 40 MMSCMD) and also priority on any residual gas after covering PNG (piped natural gas) and CNG (compressed natural gas) with a cap (of 5 MMSCMD out of 40 MMSCMD). The utilization policy recognizes that gas-based generation plants require much more than 18 MMSCMD, but has given higher priority to fertilizer and LPG plausibly keeping in mind food security issue and move towards cleaner cooking fuel to save bio-mass and to avoid polluting fuel alternatives for cooking/transport. Same priority would apply to gas produced NELP blocks. The production from D-6 field would ease the situation particularly when the gas is available to plants through pipeline wherever gas-based plants are located. Some plants, particularly off pipeline plants on liquid fuel capable of running on gas may have to wait. Going forward, additional domestic production may further ease the situation but it is clear that there are competing usage of gas which are likely to make increasing demand going further such as fertilizer, LPG, PNG/city gas etc. Also, additional domestic supply may just be enough to utilize existing capacities optimally unless imported pipeline/LNG is factored in or newer domestic reserves are found. As a policy, it would be optimal to wait for such possibilities at reasonable price before more gas-based generating capacities are allowed to come up otherwise it will increase the risk of stranded assets at the cost of consumers. Currently, there is no framework for controlling gas-based generation capacity whereas the allocation priority/linkage is assigned by the government to all gas-

based plants. In any case in a shortage situation and with pro-rata gas allocation within the sector, no merchant capacity would come up with gas based plants unless it can get the gas allocated. This aspect is, however, not clear in the gas utilization policy announced in May 2008. For example, if the gas by the private gas producer is sold to a new power generator to meet the priority even if existing capacity is idling, the policy would have been complied with even though it is socially suboptimal. The allocation should have been in favour of existing capacity to avoid stranded capacities in power sector. The practise of uniformly pro rata allocating the shortage is wasteful of resources and adds to cost in regulated industries power and fertilizer. It is also highly distortionary since user industries have widely varying costs of adjustment to non-availability of gas.

In case of imported gas, particularly LNG, price rather than availability per se is a bigger issue. The LNG prices still tend to be linked to liquid fuels and that makes them volatile. At high prices like those prevalent in the recent past, the cost of electricity generation using gas becomes exorbitant and difficult for consumers to afford. The implication is that adding capacity based on imported LNG for base load is also not advisable unless long-term prices can be locked in, which is difficult to envisage based on past experiences and the behaviour of markets. Such long-time fixed price contracts also increase contract failure risks.

Other Perceived Bottlenecks

Other than state's interest and willingness, there are issues related to fuel supply linkages, clearances and security concerns cited by the states and players as the reasons for inadequate thrust on developing potential in some of the states and areas. In some areas such as North East, the risks due to security concerns as perceived by the private sector are high. The coal and rail linkages given for domestic coal based plants are another area of concern. In case of Karnataka, for one of the plants at Raichur, the linkage has been assigned with Mahanadi Coal fields for which the coal is moved by rail to Paradip from where it is shipped to Chennai and is moved once again to Raichur by rail in the absence of direct rail linkage. It was also pointed out in Karnataka that they were asked to negotiate directly with Singreni. The utilities are not very clear about the rationale of allocation made by the relevant Central Government bodies for fuel supply (domestic coal mine and associated rail linkages). Even though the current framework of the Act and the Policies has freed the generators from obtaining approval for setting up generation capacity, there are host of other generic clearances required for setting up the capacity. Some of these are at the Central level and some are at State level. It is perceived by some players that there is a need to review and eliminate some of these whereas other clearances need to be expedited. In particular, environmental and forest clearances are perceived as taking too much time and also the queries and clarifications sought by them, many a time are perceived to be too theoretical and of little practical import. In some

cases there was little appreciation of the larger positive externalities on the environment arising out of hydro projects, the focus being limited to local impact. In case of hydro projects in North East the problem of security is perceived as one important impediment besides the lack of transmission capacity. Unless the transmission costs are fully paid for by the load centres rather than by those where transmission assets are physically located, there would be disincentive for the states where such potential exists to take or support initiatives in this direction. Some states like Uttarakhand have taken the initiative to propose “Uttarakhand Integrated Transmission Network” to enable evacuation of power from planned hydro generation in an integrated manner. There should be an enabling framework to recover cost of such network from the users of generated power rather than state consumers even though the network would be physically located in the state. This issue is taken up subsequently in transmission pricing issues.

The way forward

The Electricity Act 2003 by delicensing generation and removing techno-economic clearance for setting up capacities, the National Electricity Policy by emphasising provision of adequate returns on investment, the procurement guidelines by its insistence on competition between public and private sector after five years, and the UMPP initiative by reducing risks associated with clearances, land acquisition and in the case of captive mine based UMPPs by the provision fuel linkages, have all already created favourable climate for investment in generation capacity. Nonetheless, there are some remaining issues which need to be dealt with in case the remaining bottlenecks were to be eased-

- As discussed above, there is reluctance among the states to allow capacities to come up unless the state itself needs power. In such cases, there is expectation of getting free power or some revenues for allowing the capacity to be set up. Currently, the states can collect duty on sale of electricity and hence do not get any revenue from sale of electricity outside the state. To overcome this problem, either the state needs to be incentivised or a collective framework initiated by the Centre such as UMPP need to be created to reduce these problems for would-be investors. Central and State indirect taxes in the case of all productive activity (excise, sales taxes and service tax) are now effectively on value added basis, a VAT on electricity generation would be in order in keeping with tax reforms. This would additionally provide a vehicle for states to fiscally gain from generation located within their administrative territory, and to a significant extent would counter the unwillingness of many states to use the natural resources within their territory for use to export.

- There is a need to review the basis of domestic coal and associated rail linkages given to the domestic coal based plants. Greater transparency in revealing the basis of such allocation would reduce perceived risks and also may increase social welfare by making the allocations more optimal from the point of social costs and benefits. Indeed free pricing of coal is due in the sector and its lack is one of the reasons for the under exploitation of coal and for the dependence of Coal India on budgetary support for investments. The gap between imported and domestic coal prices create rents and hence the need to administratively allocate domestic. Coal prices need to freed up and private investments allowed, with royalty being the basis of bids for access to coal blocks. While this would raise the cost of coal for power in the short run, as investments take place and vast amounts of Indian coal are brought on to the market at low cost of production by the private and public sector units, an equilibrium without the need for administrative allocation would emerge.
- The clearances required for setting up any capacity need to be reviewed, single-window clearances or prior coordination as in case of UMPPs would reduce the risks perceived and also would reduce the time taken for completing the projects. Some of the regions where security risks are perceived as high, any capacity addition using potential available in those areas have to be exploited by CPSUs rather than relying on private sector.
- There is a need to have transmission pricing framework whereby the costs associated with the transmission network expansion required to bring additional generation to be borne by the end users primarily rather than by the consumers of the geography, where such investments are made.
- Given the low utilization of existing gas based capacity, it is important that new gas-based capacities are discouraged otherwise existing capacities will be utilized even less and will become stranded. Though the generation has been delicensed, no new gas-based capacity on domestic sources is likely to come up in the near future if the gas from newer sources were to be allocated to existing capacities. This is because of poor utilization of otherwise efficient existing capacities due to lack of availability of domestic gas in relation to demand.
- In this context, there is a case to review gas utilization policy as it only sets the priority of allocation of domestic gas from private producers. It may result in new gas-based generating stations using the incremental gas produced but may leave existing plants idling and capacities stranded. Since generation has been delicensed under the EA2003, no prior approval is required for setting capacity. The cost of existing already partly utilized capacity is being and will continue to be borne by the consumers in addition to the cost of new capacity. That would be socially wasteful and against consumer interest!
- The past experience of takeover of poorly performing plants such as Tanda, Unchahar etc. by NTPC resulted in dramatic improvement in the performance of these plants. In addition to new capacities, there is a need to

facilitate such takeover if the state sector plants continue to perform poorly despite potential. From consumers' point of view, it would be much better if the poorly performing plants were to improve rather than adding capacity for an equivalent generation and hence, incentives/disincentives need to be created to either improve the performance in a time-bound manner or takeover/privatization. The former option may be better as it would be less controversial as well.

- All these may become more important going forward as the "hot IPO markets" of 2006 and 2007 exist no more and the equity markets for providing fresh risk capital may not revive till global recession is over. In the absence of high risk appetite of the markets, promoters will be extra careful with their own money having to depend more on their own funds than in the recent past.

5.2 Competitive Procurement of Power, ABT and High Price of Traded Power

Competitive Procurement is envisaged in the Act and the Policies

One of the key objectives of guidelines issued by the Central Government, as detailed earlier in this report, is "promotion of competitive procurement of electricity by distribution licensees". Competition in generation and to facilitate the same unbundling of the sector, independent transmission utility and load dispatch centres, and trading are cornerstones of the Electricity Act 2003. In fact, procurement guidelines clearly state that the public sector entities in generation such as NTPC will also have to bid competitively to generate power for new capacities to be added by them rather the existing model of generating and supplying electricity under the Bulk Purchase and Sales Agreement (BPSA) framework. Section 66 of the Electricity Act also provides for development of electricity market (s) by the regulators under the framework of Electricity Policy to be specified by the Central Government.

The Reality Today

On one hand, distribution utilities have been using short-term contracts whenever the power requirement goes up and have been willing to pay to Rs. 8 per kWh or even more. On the other hand, system frequencies hover between 48.5 -49 Hz indicating overdrawal. Since the beginning of power exchange in last few months, the price of traded power has also been hovering between Rs. 8-10 per kWh. All these indicate lack of adequate contracted capacity by the distribution utilities.

Reasons for High Price of Traded Power

Despite these objectives laid out, there are issues in organizing competition in generation, which need to be addressed in the context of electricity sector anywhere including in India. These are discussed below. This discussion also brings out as to why distribution licensees making losses are unlikely to contract for adequate capacity (unless forced to) resulting in high price of traded power.

- In any unbundled electricity sector with separation of generation, competition in generation can be induced done in two ways. It is possible to create competition for capacity and for the energy produced (electricity generation) separately. An alternative is to induce competition on the combined price for supplying capacity as well as energy. This issue is particularly relevant because capacities in the sector use different sources of energy such as coal, nuclear, hydro, gas, wind, liquid fuels etc. Some of these have very low variable costs and others very high. These technologies also differ in the fixed cost associated with capacities created and also in the flexibility with which the outputs of plants can be increased or decreased. Traditionally, one of the arguments in favour of vertically integrated utilities has been that their profit maximizing (or cost minimizing) behaviour results in adherence to merit order. When regulated under price cap or cost plus regulation, they have no incentive in not maintaining merit order. Merit order refers to use of low variable cost capacities first, subject to flexibility and network constraints while supplying electricity and switching on (dispatching) higher cost generation for peak loads. Merit order dispatch does not factor in the fixed costs associated with the capacities as they are sunk and irrecoverable. Merit order based dispatch is consistent with maximization of social welfare as it results in saving of scarce resources (fuel) for supplying any given demand.
- In case the market and competition is organized with capacities being traded separately from the energy with capacity contracts not linked with production of energy (generation of electricity), then the buyers and sellers (generators) would have to compete separately for capacity and energy. In such a case, the dispatch of energy is likely on the variable cost consistent with “merit order”. In the absence of a central market, this objective is achieved through “two-part” generation tariffs or prices. One part of the tariff in any two-part tariff covers the fixed costs and the other variable costs or energy costs. Analogously here, one part of the cost of procurement arise on account of the market price /contract price for capacity contracted and another due to the market price / contract price paid for energy. Dispatch or scheduling decisions in such a case is based on variable costs or on the bids for energy delivery (energy part of the tariff) and not on total costs / prices/tariff.
- In an energy-only market, the generators which are cost-effective (on total cost basis) are expected to enjoy “rents” if they get paid through spot prices. Conversely, the marginal capacities (peak load types with high total costs) are exposed to greater risks and the only way they can hope to recover their

capacity costs in an energy-only market is through very high “spot” prices. The buyers would be very keen on long-term contracts with the cost-effective generators but the generators would not be so keen. On the other hand, the marginal generators would be keen on long-term contracts but the buyers won't be overly interested. If an energy-only market starts with tight capacity situation, the marginal (peak load) capacities are unlikely to come up till spot prices are sufficiently high. Later, the spot prices in an energy-only market are expected to be volatile if there is growth in demand. This argument against energy-only market does not hold if there is excess capacity in the system or if there is scope for creating more cost-effective capacities than the ones existing. If the former condition prevails, capacity creation is a risk and the end effect is that some capacities will get stranded and this would result in lower cost to the consumers at the expense of investors in costly capacity. In the latter scenario, capacities will get created and will push some of the existing capacities to marginal level.

- Based on the analysis above, the choice of inducing competition on energy-only basis (as opposed to capacity and energy separately) in generation depends upon whether there are assets (capacities), which need to be stranded (without any payment by the consumers) or whether there is a need to assure capacity charges so that more capacity comes up. In Indian context, if one were to go on the basis that capacity creation going forward is more important (due to unmet demand and growth in demand at rates higher than 5% that is likely to be there over the next 30 years at the very least) than making existing capacities stranded, then it makes sense to have both capacity and energy markets. If the market does not have enough capacity contracted and single part tariff competition is allowed, everyone has interest in avoiding paying payments related to contracted capacity for peak load and would like to free ride on the system. Formally, the framework in Indian context, whether it is the tariff policy or ABT or the procurement guidelines, recognizes the importance of “merit order” and have “two-part” or “multi-part” tariffs to preserve the same. However, the dispatch of traded power or power procured for short-term is based on composite or single tariff, where the preservation of “merit order” is not assured nor is it probable. More than the “merit order”, the lack of insistence on capacity contracting for power in the presence of ABT regime and short-term trading creates incentives for not contracting capacity for longer periods. And this may indirectly affect the quality of supply as discussed below.
- While ABT has been introduced to deter overdrawal from the grid and merchant power or short-term contracts are now allowed to contract for energy, there is no formal insistence on buying capacity (though in effect ABT is motivated by the same concern). Since there is no capacity cover requirement in participating in the UI market, there would be a tendency on the part of buyers to buy the power when their requirements have high value (political or economic) in the short-term market even at high prices rather than make

commitments by contracting for capacity. One would guess it is 'optimal' to pay UI charges than pay for capacity charges if the period for which energy is required is uncertain and short. It should therefore not be surprising if very short-term traded power is priced close to maximum UI charges in peak periods! The fact that distribution utilities have high losses, that they can shed load arbitrarily (on non-economic considerations) makes it easier for them to overdraw rather than contract for providing reliable supply as that would have the impact of increasing cost of supply resulting in consumer resistance on one side and possible higher financial losses due to unacceptably high commercial losses in case they were to supply reliably without shedding load.

The way forward

Based on the discussion above, it is evident that the following issues need to be addressed in the policy and regulatory framework to promote competition and for provisioning of improved quality of supply.

- Currently, there is no explicit provision in the Act or the policies, which requires that the distribution licensees adequately contract for their power requirements or capacity except for their obligation to supply reliable and quality power based on performance standards laid out by the ERC (section 86(1i)). In fact, the procurement guidelines require taking approval for procuring more than projected requirements but not for ensuring adequate procurement.
- Unless the ERC can insist and enforce either the performance standards in terms of limits on load-shedding or adequate contracting by the distribution licensee, any loss-making, high commercial loss laden distribution licensee is unlikely to contract for more than the bare minimum required to avoid payment of capacity charges. Instead it would prefer UI route or short-term traded power to be used whenever absolutely required (for political or other similar reasons) and to shed load otherwise. The above need not be true for profit-making utilities since they would proactively contract and serve all their customers in the pursuit of profits. Most distribution entities under State control of their operations and facing both shortage and losses adopt the practise of distributing the shortages across all consumers rather than maximising the supply to those who pay and do so at rates significantly above the cost of supply. Doing so could have increased their revenue flows and even allowed them to improve subsidisation. But given their 'logic' of administratively allocating power cuts, there is little desire to contract for capacity with a view to improve the situation of supply during the peak hours. While under section 23 of the Electricity Act, the SERCs can issue direction on equitable distribution and under section 86 (1i) can specify quality levels, non-compliance can at best only evoke penalty ex post.

- In the current framework, there is no incentive for anyone to contract for or to invest in peak power as the capacity charges would have to be paid for or recovered for the day despite using the capacity for only a short period of time. The peaking power or such short-term power would have to be supplied at high prices to recover full costs over a short period of time. But for the load shedding, the peaking power would have been even more costly.
- To incentivise adequate contracting and to disincentivise load shedding and overdrawing, provisions available to ERCs in the Act may not be very effective as they are based on instances of violation of performance standards if they are part of regulations. Instead, tariff fixation itself should penalize and reward such behaviour. That means lower tariffs should be allowed if UI or load shedding is resorted to and higher tariffs in case reasonable power has been contracted.
- Not allowing high cost of short-term procured power or UI charges are unlikely to be effective as the utility would still be better off not contracting as the absolute amount would be low if used for very short period and load shedding is resorted to otherwise.
- High cost/price of electricity for base load periods and high price for peak periods reflects different problems in the electricity sector. While the former is a consequence of lack of adequate supply relative to the base load demand, the latter is a consequence of capacity cost recovery by merchant plants that are not paid for during idle period. Capacity addition and the operating efficiency are the reasons for the former and very sharp peak loads are reasons for the latter. The regulators, therefore, must insist on demand side management measures to flatten the load curve through time of the day tariffs and energy efficiency measures in the short run. This would in a situation of markets mean movement away from UI to actual price discovery. This would also force up frequency to convergence at 50 hertz and not let it vary between 48.5 and 50.5 as it does today.

5.3 Trading in Power and Its Regulation

Provisions Related to Trading in the Act

In the Electricity Act 2003, trading has been defined as “purchase of power for resale thereof”. The act under section 12 requires anyone interested in trading to obtain licence. Distribution companies are exempt from this requirement under section 14. Under sections 38, 39 and 41, CTU/STUs and transmission licensees are not allowed to trade in electricity. By implication, any trader in the sector can either be an explicit trading licensee or a distribution licensee. Section 79 and 86 of the act empower the CERC and SERCs respectively to regulate the trading margin if they

deem it necessary. Based on the provisions in the Act, the CERC defined the terms and conditions for inter-state trading licence, and also put in place the trading margins for inter-state trade at 4 paise / kWh.

Problems in Regulating Trading Margin

Firstly it is not clear that regulation of trading margin is desirable if the objective is to increase competition. Instead, increasing competition may be the best way of reducing trading margins. Even if it is assumed desirable, there are difficulties. If a distribution licensee were to buy power with the intention to trade at a higher price to others, it may not gain commercially but it can use the trading to subsidize its own consumers at the cost of others, which is allowed as on date. Regulating trading margin is not feasible in such a case. Instead of trading, i.e., purchasing for resale, it can also retain or create capacity suitable for trading. For example, Purulia pumped storage capacity in West Bengal is with the distribution utility which can be used to generate peak power. Generators, particularly merchant plants similarly can sell power at high price without any regulations unless ERCs specify maximum price at which distribution licensees can buy from generating companies through short-term contracts under section 62. Generators can acquire trading licence for themselves or may trade through their sister concerns or may use UI to inject power, depending upon what is commercially most advantageous to them.

Another issue, which creates difficulty in regulations, is that any transaction can be put through multiple traders, it is not clear whether trading margins for each of them would be allowed and many such layers can be allowed or used before the power is sold to end consumers.

The way forward

Given the nature of trading and difficulties involved in regulation of trading, trading margin regulation provisions should not be used. The only way the price difference between cost and sale can converge is when competition increases, supply responds and demand adjusts. High trading profits point to opportunities and limiting the same only kills the incentive to move power from surplus to deficit areas. It also limits the response of non-merchant investments to stretch out the capacity utilisation of their plant on a steady basis. Margin limits on trading is an anathema to the development of markets. Similarly, there cannot be limitations on the number of layers through which traded power can be put through.

5.4 Developing Market in Electricity Sector

Issues in Creating Wholesale Markets

Gross Pool or Net Pool (PX/ISO) Model

Wholesale electricity markets were initially organized as tight or gross pools for example in Chile and UK. In a gross pool, all transactions are mediated through the pool whereas in a net pool, only imbalances are mediated centrally through the market. The bilateral contracts provide the basis of a net pool and such contracts are facilitated through Power Exchange(s) (or PX). While most markets world over operate as Gross Pool, UK has moved over to a bilateral contract driven market under New Electricity Trading Arrangements. Nord Pool is also a voluntary pool and hence can be classified as a net pool. Most of the other markets in US, South America, Australia and Philippines are organized as gross pools. The advantage of a gross pool are that the spot price formation is more robust and to the extent these prices are important signals of marginal cost and utility of the electricity, the case for a gross pool is stronger than a net pool. The risks associated with spot price movements can be easily mitigated if bilateral financial (but not physical) contracts are also allowed. Absence of such contracts can lead to problems as was witnessed in Californian crisis. Extensive use of such contracts also reduces the incentive to game the market for the generators.

The risk to any generator in case the generator is “constrained off” due to congestion, can also be mitigated by using “financial transmission rights” (FTRs) as is prevalent in several US markets and also WESM of Philippines. In case the generator holds the appropriate FTR, then the profit foregone by the generator is available to him through congestion charges by holding FTR. Organizing markets or the sector as gross pool or net pool also has implications for whether the dispatch is based on energy costs (bids) or the bids based on recovery of capacity and energy costs. Gross Pools can have separation of capacity and energy markets but not net pools particularly if the net pool is relatively small and is seen as “imbalance” market. Organizing competition in generation on gross pool or net pool also has implications for the level of powers and controls for the system operator(s). Gross pool calls for greater control on network by the system operator. Both these issues are discussed in greater details later. Currently in India, the framework in the sector is mainly based on bilateral and multi-lateral contracts between generators and buyers (DISCOMs). The scheduling though is through RLDC/SLDCs in a centralized manner similar to a gross pool. Unlike a gross or net pool, currently there is no compulsory or voluntary bidding by the generators to discover “spot” prices. The “imbalance” market currently is through ABT (availability based tariffs) and UI charges to discover the equivalent of “spot prices” linked with frequency, a proxy for on cost and value (supply and demand) of electricity. The imbalance is

with reference to day-ahead schedule to supply and draw power for every 15 minute slot. Entities participating on the supply side – generators and embedded generators in distribution entities cannot hold back available capacity from the schedule. The “spot prices” are pre-specified at each frequency around 50 hertz change as the frequency falls (excess demand or undersupply) or rises (excess supply or under drawl).

Separate Markets for Capacity and Energy or Energy-only Market

As discussed earlier, ABT is not a robust solution to the objectives of creating incentives for capacity addition and simultaneously preserving merit order in dispatch. An alternative to ABT would be to tie-up existing capacity and energy contracts between generators and DISCOMs as they exist and create a market on gross pool basis with separate capacity and energy markets, and prices emerging for both. This would allow the existing contracts to be used for effective prices to be paid by the DISCOMs but would allow emergence of spot markets for capacity and energy. The DISCOMs should tie-up the capacity before they requisition for energy. In case not tied-up, they have to pay for capacity as well as energy simultaneously. Another alternative would be to not make it mandatory for all of the capacity or the energy to come on to the market but to allow even only an “imbalance” market based on bids and offers. Both options would necessitate moving away from frequency and pre-fixed prices to price discovery. Both options would require greater control on system operators (or load dispatch centers) and players in the sector. In India, despite recognizing the importance of two-part tariffs in dispatching /scheduling generators, currently the trades take place on combined tariffs. While bulk of the scheduling /dispatch decisions are based on variable costs, the traded power (on energy-only basis) actually gets to be scheduled on total cost basis. The new breed on merchant power plants, coming up under the new policy framework (Case I and II) , are also likely to be scheduled on total cost basis (or contracted energy charges under long-term PPAs rather than on real-time bid basis). In any case, there is no bidding to reveal “true” marginal costs on real time basis.

Independent System Operator and Its Role

For any kind of competition to emerge at the wholesale level, the transmission network has to be owned and managed by player(s), who have no commercial interest in the competitive market. The same is true for distribution network for competition at the consumer level. The network operator cannot exercise any kind of bias vis-à-vis buyers and sellers. His behaviour has to be governed by the need for energy balance, system reliability, assurance of control (and similar other objectives) being met on real time basis. Subject to these

objectives and constraints, any commercial outcome should be as good as any other for the system operator.

To achieve the above in the context of competition, system operator is not allowed any other interest in the sector (and at times is not even the owner of transmission network it manages) but is allowed full control on the operation of network subject to regulatory oversight. The idea of Independent System Operator and Open Access has been key to promotion of competition in an unbundled electricity sector. Any such ISO requires complete control over the network and should be able to issue binding instructions to dispatchable entities (generators and loads) even though it may have no commercial interest. In India, currently the system operators (RLDCs/SLDCs) are only involved in scheduling and dispatch decision and do not have similar control. More importantly, they are not truly independent of the entities which have commercial interests (DISCOMs and generators) due to historical reasons. And since much of the sector consist of state-owned entities, and the personnel manning the RLDCs/SLDCs are drawn (typically on deputation) from these SOEs entities. Any behaviour and actions that could go against the interest of SOEs in generation and distribution are generally abhorred.

Market Power

One of the major concerns of the policy-makers and the public has been the possibility of exercise of market power by the generators by quoting a very high price of marginal plants in case very few generators are competing in the spot market. While quoting high is not likely if there is enough competition (and capacity), this danger lurks in case the marginal plant(s) likely to be scheduled can be guessed correctly and if demand side response is weak (due to inelasticity of demand or due to small quantum of dispatchable load). The exercise of market power is less likely if there are enough capacities and players and also if most of the capacity is on long-term financial contracts. In the latter case in the context of a gross pool, where every generator has to bid, the incentive to game is considerably reduced as the gains from gaming and setting high spot prices are low. In WESM Philippines market for example, only 10% of the offers need to be outside bilateral contract. The incentives are very high if the bilateral long-term financial contracts are not allowed, one of the weaknesses of Californian market, which led to the problems in 2001. Another way to lessen this problem would be to specify a price cap, as in case of Australian market. How high this price cap should be given price inelasticity of demand is a call to be taken by the policymakers and regulators? If it is set too low, the purpose of market price (to signal scarcity value) is defeated and keeping it very high increases the incentives to game the market. Given the demand-supply situation in India, it is not easy to create spot markets without

eliminating gaming opportunities to start with . However, if all existing long-term contracts are retained as financial contracts then the incentive to game would be very low for the existing generators if they were to bid in the spot market. This would also not impose any tariff shock to the retail consumers. Only some pre-defined consumers, who are on TOD meters, may be expected to bear the risks associated with spot market prices. More importantly since the shares of agricultural and industrial demand are high, and incomes of households are low, there is significant demand side price elasticity. This is good for the price discovery process since more than only the prices having to respond in case of shortages demand can respond through re-scheduling to off peak periods, and by acceptance of power cuts and interruptions etc. Nevertheless the peak prices in any well designed market would be significantly higher than current UIs but the response through capacity additions can also be expected to be large since growth of demand can be assumed. So if the supply side is allowed to respond to the same dynamically then such high prices would not remain for long. In a situation of growth a capacity created ahead of demand need not remain unscheduled for long. Thus markets may be more optimal and serve the social purpose better in India.

Wholesale and Retail Market Inter-linkage

A major problem witnessed during Californian crisis was related to the lack of the required linkage between wholesale and retail markets. If the high wholesale prices are not allowed to be passed through by the regulation to the retail level (as was the case in California), the distribution utilities are destined to become bankrupt in case wholesale prices remain high. This is particularly so if the DISCOMs and suppliers have to buy from spot markets and are not allowed to hedge through financial contracts. If the demand side bidding is not allowed or the demand side is protected from the changes in supply-demand situation, the prices are only determined by the cost of supply and not the value of electricity in alternative usage. At least large users should face the prices of using electricity at any given point in time for the markets to adjust on the demand side as well. This is possible if there is time-of-the day-metering and a framework, which allows demand to respond to emergent demand-supply situation.

Transmission Pricing and Investments

One of the problems cited in the context of unbundling the sector and making generation competitive is that unlike a vertically integrated utility which can jointly optimize the investments in generation and transmission (by keeping the sum of life cycle costs of both the lowest possible), there is no equivalent framework for investment decisions in an unbundled sector. An optimal location for generation depends on transmission network capacities and configuration and an optimal transmission network depends on the generation locations and

capacities assuming load-centers as given. An example of this problem is network congestion leading to less costly generator being constrained off. If the transmission pricing framework allows for pricing electricity factoring in congestion, then the price would provide appropriate signals for transmission network strengthening but not for generation. The nodal pricing mechanism in such case would signal the need to remove congestion but would also signal locating generation plants closer to the nodes having higher prices due to congestion. In case global optimum for generation and transmission requires a new location and transmission network expansion to that location, a central planner is required and the markets are not expected to achieve such optimum on their own. This problem is meaningful and serious if the network is not very dense and requires expansion as in case of India at the cross-regional level. In addition to congestion related charges, the wholesale markets should determine the loss factor depending upon the location (or node) of withdrawal. Currently, the losses are pooled which may not discourage loss increasing flows and may also not encourage loss reducing flows

The way forward

To summarize, the following issues need to be addressed for development of markets-

- ABT based management of imbalances does not ensure the long and medium term response of the system to overcome consistent imbalance in one direction (shortages). This is because investment decisions cannot be made on the imbalance revealed by the ABT unless these imbalances become very large and reflect themselves in the form of persistent low frequency, over draws, and high cost of traded and peak power. ABT cannot provide a vehicle to link competition for the market (involving investment and entry decision) to competition in the market (i.e., with regard to operational decisions) through the competition for dispatch.
- At present, while bulk of the scheduling /dispatch decisions are based on variable costs, the traded power (on energy-only basis) actually gets to be scheduled on total cost basis. The new breed on merchant power plants, coming up under the new policy framework (Case I and II), are also likely to be scheduled on total cost basis (or contracted energy charges under long-term PPAs rather than on real-time bid basis). In any case, there is no bidding to reveal "true" costs on real time basis.
- An alternative to ABT would be to tie-up existing capacity and energy contracts between generators and DISCOMs as they exist and create a market on gross pool basis with separate capacity and energy markets, and prices emerging for both. Another alternative would be to organize the imbalance market on net pool or energy-only basis but to accept high price volatility in imbalance market.

- In a gross pool, the DISCOMs should tie-up the capacity before they requisition for energy. In case not tied-up, they have to pay for capacity as well as energy simultaneously but separately. In the net pool, it would not be mandatory for all of the capacity or the energy to come on to the market but only an “imbalance” market based on bids and offers is required. The bids and offers would be on energy-only basis without separate capacity charges for electricity procured through market. Both options would necessitate moving away from frequency and pre-fixed prices in the spot market to price discovery. Both options would require greater control on system operators (or load dispatch centers) and players in the sector by the regulators. Over draws and under injections would have to be settled on real time basis through market prices rather than frequency linked prices.
- The exercise of market power in a bid and offer based real time spot market as opposed to ABT based imbalance market is less likely if there are enough capacities and players and also if most of the capacity is on long-term financial contracts. In the latter case in the context of a gross pool, where every generator has to bid, the incentive to game is considerably reduced as the gains from gaming and setting high spot prices are low once the existing contracts are considered as financial contracts whereby the generator may decide to buy from the or generate depending upon the price already contracted. Any gains from high prices are notional as the generator with existing contract has to pass on these gains to buyers.
- The concern of exercise of market power in Indian context is real given the demand-supply situation in India. It is also recognized that it is not easy to create spot markets without eliminating gaming opportunities. However, if all existing long-term contracts are retained as financial contracts then the incentive to game would be very low for the existing generators if they were to bid in the spot market. This would also not impose any tariff shock to the retail consumers. Only some pre-defined consumers, who are on TOD meters, may be expected to bear the risks associated with spot market prices. Another way to lessen this problem would be to specify a price cap, as in case of Australian market. How high this price cap should be given price inelasticity of demand is a call to be taken by the policymakers and regulators? If it is set too low, the purpose of market price (to signal scarcity value) is defeated and keeping it very high increases the incentives to game the market.
- For the markets to respond to real time prices, the wholesale prices need to be passed on to the end consumers at least to large consumers through TOD metering and TOD tariffs.
- The real time markets would also require real time system operator support in determining congestion and security constraints (so that infeasible contracts are not entered into) and the transmission prices need to be such that they reflect marginal losses and congestion charges if there are any congestion in the system.

5.5 Open Access and Reduction in Cross-subsidies

Open Access to Promote Competition

The Electricity Act, under section 42, clearly spells out phased introduction of open access for consumers and reduction in cross-subsidies by SERCs. In a subsequent amendment, the deadline for declaring open access for consumers having load of more than 1 MW has been fixed as January 2009. Though SERCs are allowed to fix a cross-subsidy surcharge, yet the National Electricity Policy emphasizes the need for not fixing the surcharge at a level where the competition envisaged through open access in the Act becomes meaningless. Clearly, the open access of wires to be used by certain category of consumers has been seen in the Act and in the policy as a way of introducing the competition among generators and suppliers (distribution licensees).

The Reality Today

Quite a few (such as Karnataka, Tamil Nadu, West Bengal, Assam etc) SERCs have declared open access regulations for certain categories of consumers (usually above 1 MW). The cross-subsidy surcharges vary from zero in case of Maharashtra, Haryana, Tamil Nadu and Uttarakhand to the order of Rs 0.5-1.50 per kWh in other states. In most cases, very few consumers applied for open access and practically no one is availing open access even when granted. Typically, wherever open access request were made, transmission constraints were cited as the reason for denying open access even when the consumer was already connected and the load was being served by the distribution utility. Distribution utilities, in concert with the transmission utility, were not very keen on allowing open access despite regulations put in place by the SERC. Even when allowed, such consumers have refrained from using the open access allowed due to various reasons such as reluctance of SLDC/STU in wheeling power, perceived threat of distribution utility and also tariff rationalization attempts by SERCs by not allowing industrial tariffs to go up.

Reasons for Not Using Open Access

In our interaction on the ground, the following reasons were cited for not using open access- (a) level of cross-subsidy surcharge in relation with the tariff, (b) lack of availability of firm long-term power at competitive price from the market, (c) cost and reliability of standby power arrangements in the event of contract failure, (d) asymmetric bargaining power of the utility to create hassles on day-to-day/ real time basis, (e) Non-arm's length relationship between distribution

licensee and the STU/SLDC, and (f) the stance of the SERC to reduce cross-subsidy. These are elaborated below.

As pointed out the surcharge declared by the SERCs are of the order of Re. 0.5-1.50 per kWh. Given the fact that the tariffs in some of the states such as West Bengal are low and the firm power from outside is either not available or costly, it does not make too much economic sense for the consumers to avail open access. Some of the consumers, for example in Tamil Nadu, are availing open access for their own capacities (captive or wind etc.) but not for third party sale. Any consumer opting for open access has to also worry about standby arrangement in case the contracted power does not materialize. In such cases, they have to ask for standby arrangement from the incumbent distribution licensee and have to pay at tariffs equal to “temporary connection charge”. The utility is also seen to be not friendly in such cases by the consumers and there is a fear of utility either directly or in conjunction with STU/SLDC affecting the quality of supply thereby imposing costs on the consumers. Such fears are not completely unwarranted as is discussed later in issues related to independence of STU/SLDC and constraints related to enforcement by SERCs. There have been several cases before SERCs and CERC where the open access has been denied by the load dispatch centres. In a case (24/2007) where Tata Power Trading Co wanted to wheel the power generated by M/S. Nava Bharat Ventures Ltd located in Orissa, the WRLDC refused open access for 27 MW through ERLDC and Orissa SLDC because of lack of consent from OPTCL (the STU). It is on record that ORTCL wanted the Nava Bharat to sell power to state utilities despite the order from OERC. STUs have tried to create grounds such lack of SCADA and PLCC which will purportedly result in difficulties in settlement of UI charges. This is despite the fact that there is no reasons of online monitoring of injection/drawal except special energy meters. There have been cases involving Karnataka STU (KPTCL) by Ugar Sugar Works, Shree Doodhganga Sugar Co-operative (Petition # 114, 116/2007) where the CERC had to reiterate that the STU and the SLDC should act in an impartial manner concerning open access as per the law and regulations. Still, there are pending cases against KPTCL / Karnataka SLDC (petition # 147,153.156, 157/2008) including matter of wilful disobedience of order of CERC. There have been also cases pending against Tamil Nadu SEB (petition 121, 158/2008) and Rajasthan STU (petition 60/2008) in the CERC. All these point to reluctance and inability of STU/SLDCs to act as independent system operators.

The way forward

There are several issues, which need to be resolved if open access to wires of transmission and distribution utility were to be used by the end consumers to bring about competition in the sectors. Some of these are related to independence of STU/SLDC and the power of SERC to enforce regulations while dealing with a state government owned and controlled distribution utility. These are discussed

separately in other sections of this report. Besides these, the following need to be addressed to ensure open access to be implemented in the spirit of the Act:

- The cross-subsidy surcharge needs to be lowered so that the end consumers may find it economical to avail of the open access. While this has been done by several states, other states' SERCs need to review and lower the same.
- The standby charges also need to be reviewed and should be reasonable if the objective is to promote competition through open access.
- Besides surcharge and other charges, there is a need to ensure that the SLDC/STU are not acting in the interest of the distribution licensee and that there is no implied threat by the utility on the ground in terms of reliability or quality of supply.

5.6 Transmission Pricing Issues

As pointed out by the tariff policy, there is a need to evolve a national tariff framework for transmission tariffs, which are sensitive to quantum, direction and distance of flows. Currently and in the past, the transmission tariffs for the intra-state network are based on pooled cost of the network in the state and charged from consumers based on through put of the system as a per kWh charge. Similarly, the losses are pooled over the state system and the cost associated with losses is also recovered from consumers based on throughput as a per kWh charge. Obviously, the present framework is not sensitive to direction and distance of flow of electricity and the charge is same irrespective for all within the system. The inter-state system is also based on same principle called "postage stamp" pricing by aggregating the costs within a region and allocating it to utilities based on the proportion of their use of the inter-state system. Such a pricing regime obviously does not provide incentives to the users of the grid to take optimal long run or short run decisions in terms of location of generation or consumption. It also does not provide any incentive to the grid operator to improve efficiency of grid or investments for future. The postage stamp pricing also creates disincentives for those states and users to block expansion of the network whose demand is not growing as they have to pay proportionate cost of expansion despite not partaking the benefit of expansion.

Issues in regulation and pricing of electricity transmission

Transmission of electricity needs to be regulated like any other natural monopoly to prevent abuse of market power. Unlike other investments or networks such as gas, telecom etc., which may be amenable to contestable markets, there are considerable economies of scale and scope in providing electric transmission

services. Transmission has additional characteristics – load flow- that makes it very different from other natural monopolies like gas distribution or electricity distribution network. Its regulation influences the behaviour in other markets- generation and ancillaries, supply and demand. Typically dense transmission networks unlike distribution networks cannot be broken up into smaller entities. Spatial separation may not be possible unless the network is sparse. The standard solution to regulation of an entity having natural monopoly entails capping the effective return of such entity through rate-of-return, price cap regulations or eliminating the incentive for abuse of market power through public ownership. So is the case with transmission services in electricity sector world over. The objective of these regulations is that the prices should reflect short run and long run marginal costs of resources used to produce the output. However, regulating the electric transmission entities imposes certain constraints and raises issues peculiar to them. Firstly, electricity, following Kirchoff's law, flows on parallel paths and gives rise to loop flow problem. In addition unlike some other commodities, it is not amenable for storage. In an integrated network, the loop flows can create negative as well as positive externalities by the action of players upstream and downstream. This needs to be handled by the transmission service provider in terms of operating decisions as well as priced to achieve economic efficiency (merit order). If as a regulated entity, the transmission service provider charges price, which does not take into account such loop flows, then the consequences of actions of players are not internalized by them, affecting merit order dispatch. Secondly, the transmission prices need to capture the line losses and system constraints through prices to promote efficient investment, generation and consumption decisions upstream and downstream in the long run as well as short run. The prices should send signals, which facilitate optimal location decisions geographically for generation and consumption of electricity in short-run and long run. Thirdly, like any regulated monopoly the transmission pricing should provide adequate returns on the assets to the owners so as to avoid stranded costs. Fourth, the pricing should signal and help in management of network and optimal investments in transmission resources. Lastly, the pricing regime should be simple and transparent to act as an effective signal. Though the wish list seems intuitively simple, there are several complex issues in simultaneous attainment of this wish list, which has attracted considerable attention in the sector. The problem with the above wish list is that the objectives at times could be contradictory for any given pricing regime, depending upon the network characteristics and constraints. As the marginal costs in the short run are a small part of total/ average costs (due to large upfront investments required); the short run marginal costs differ substantially from long run marginal costs. Similarly, marginal losses are approximately double that of average losses on a network. Nonetheless, transmission pricing on the basis of marginal costs is optimal for consumption and generation decisions.

Three Basic approaches

The three basic approaches towards transmission pricing have been- (a) postage stamp, (b) distance related, and (c) nodal pricing. Out of these three approaches, the postage stamp approach is the simplest and has been widely used including in India. In case of postage stamp pricing, a fixed amount per unit of energy is charged for a given amount of energy to be transported over the network irrespective of the distance or voltage level. The objective of such a pricing is to simply allow the transmission service provider and grid owner to recover all the costs associated with the ownership and operation of grid. Such a pricing regime has limitations spelt out earlier.

The distance based pricing approach is as the name suggests, based on distance between generator and the customer. The approach is based on assumption that the power flows through shortest route on the network. It provides incentive to locate the generation close to customers even if there is spare capacity on the transmission network. In the process, it can hamper merit-order dispatch by favoring costlier generation as long as it is close to the customers. Based as it is on an invalid simplistic assumption, it doesn't discriminate between congestion causing flows and congestion relieving flows.

The last of three basic approaches, namely, nodal pricing is based on short run marginal cost of transmitting electricity over a network. It is based on an explicit system model, which takes into account losses as well as constraints. The entire network is conceived of as nodes, demand or generation. The model schedules the optimal generation reflecting losses and system constraints after taking into account actual flows for a given demand and supply schedule. The demand and supply schedule is drawn on the basis of bids in the context of competitive markets for generation and supply. The model works out the transmission prices at each node for the optimal generation reflecting marginal costs associated with losses and constraints for each node. Nodal pricing, though relatively complex compared to other basic approaches, reflects appropriate marginal costs and results in correct geographical signals for the upstream and downstream parts of the sector in the short run. By itself and in general however, nodal pricing will not be adequate to recover all costs associated with the network. If the network is unconstrained, then the nodal prices will reflect marginal line-losses and would lead to capital costs being stranded. Worse still, nodal price based revenues for the transmission provider can create perverse incentives to earn through creation of bottlenecks. Though nodal prices may signal appropriately the need for network expansion or strengthening to remove constraints, they cannot be the basis of recovery of costs associated with investments as *ex-post* nodal prices will be different from *ex-ante* nodal prices. In case of interconnected networks, the nodal prices may not even adequately signal the need for investments if the best

way to remove network constraint is by way of investment on some other network. Despite these shortcomings, nodal prices, as earlier pointed out, reflect short run marginal costs associated with transmission resources for upstream and downstream parts of the sector by explicitly accounting for line losses, externalities and network constraints. In order to recover sufficient revenues for transmission resources however, standard regulatory interventions are required.

While the first approach of postage stamp pricing is neither distance nor direction sensitive, the second approach of MW mile is sensitive to distance but not the direction of actual flows. First two approaches also do not distinguish between short-run and capacity costs. The third approach of nodal pricing factors in all short run costs such as losses and congestion and is therefore sensitive to direction and distance but it ignores capacity or sunk costs to be recovered. The sunk costs of network also need to be recovered but it is difficult to allocate the sunk costs as these costs are joint fixed costs. They can be allocated on the basis of distance or reliability, which a network facilitates. They can also be allocated with some arbitrary combination of the two based on the relative weight assigned. Besides arbitrary allocation of sunk costs, all these methods do not provide basis for expansion of network or investment in network even though nodal pricing approach does signal where the congestion are for given supply and demand patterns on the network. Nodal prices also create uncertainties for the generators and consumers in case the flow pattern changes and network gets congested on the links, which affect them. To reduce this risk, financial transmission rights have been proposed and used in some markets.

New approaches for long term transmission access

Recent developments in transmission pricing have focussed their attention on development of long term transmission rights, consistent with short-run price efficiency attainable through nodal prices. These are viewed as critical for the players to insure themselves against locational price risk faced in the spot market and for signalling investment in network. Recognizing that point-to-point access transmission contracts may turn out to be infeasible, a number of new approaches have been suggested to allocate transmission right. The transmission prices based on point-to-point rights clearly would not take into account the externalities caused by loop flows. The transmission rights in the context of power trading proposed are *financial* or *capacity-reservation based*. Similarly, *point-to-point* and *flow-based* right have been suggested.

Noting that nodal pricing and proposed link-based transmission congestion contracts by themselves are not enough to create optimal incentives for socially optimal investment in transmission, the concept of *incremental surplus subsidy* for investments in the transmission sector has been proposed by a few academicians. The basic idea is that the transmission asset owner / service providers is allowed

for one period the entire surplus made available in the system from the investments, so that he has incentives to undertake socially optimal transmission investments. After one period, the returns are capped. After reviewing the developments in transmission pricing and transmission rights, some other have concluded that the ISO (independent system operator, of the transmission resources) will have to continue coordinating grid investment decisions in the near future.

The Way Forward

Recognizing the problem of recovering sunk costs through transmission tariffs, one possible framework for transmission tariffs can have following elements:

- (a) Connection charges related to specific and dedicated assets related to a particular set of beneficiaries to recover capital costs,
- (b) Capacity charges for the network (as opposed to specific assets) to recover capital cost based on typical flow patterns based on distance of flows or contract path method, and
- (c) Nodal pricing based charges to reflect congestion and losses.

The proposed framework will allow recovery of sunk costs in the form of capital costs of both dedicated as well as network assets. It will also signal the marginal costs of causing congestion on specific links by having a nodal pricing based short run charge. The revenue collected from the nodal pricing based charges can be used to reduce the network related capacity charges. Since the congestion costs are not passed on to the consumers in the absence of timing of the day pricing as well as absence of electricity markets, the congestion charges can be scaled up to reflect the social costs of congestion as well as to promote grid discipline. The rationale for making distinction between dedicated assets and network assets is that network assets can be conceived of as common resource. The utilization as well as strengthening of network should not be dependent on one or a set of beneficiaries. Though systems and procedures for co-ordination required for such investment need to be spelt out by the regulator, the free-rider problem faced in such situations can be taken care of by denying veto power of any beneficiary on such decisions. Having tariff framework linked with capacity charges for the entire network, as opposed to specific lines or part of the network will also pave the way for development of transmission highways and network strengthening as the recovery of tariffs will be through proportionate capacity charges for the network assets and not on the basis of bulk-power supply agreements, as is the case today. While in case of dedicated assets, the specific beneficiary (generation or supply utility) will

pay the capacity charge, the network capacity charges will be payable only by the supply utilities or licensees collectively in the proportion of their use of system in terms of kWh of power drawn. By incorporating the typical flow pattern while allocating capacity costs, the recovery of costs can be made distance sensitive. If reliability brought by the network is also considered, 20-30% of all capacity costs can be allocated to all consumers irrespective of distance but the remaining can be based on MW mile approach or average distance of flows based on "typical" flow patterns. One way to do would be to allocate the capacity charges to reflect the length of links in network attributable to a particular beneficiary based on contract-path simplification. The proportion of average of shortest contract paths used by a beneficiary could be used to reflect the physical lines used by a beneficiary.

The objective of both connection charges for specific asset as well as capacity charges is to provide for recovery of sunk (capital) costs. The remaining element proposed is nodal pricing based charges are meant to recover to signal the cost of congestion and line losses. Based on explicit system model and actual dispatch schedules, the nodal prices can be computed periodically. In the event of congestion, the nodal prices will reflect marginal cost of power at each node as discussed earlier in this paper. The nodal prices are based on demand and supply bids at each node in the network. As electricity markets may take time to evolve in India, the nodal prices can be worked out based on *actual marginal operating costs of generators* scheduled for meeting a given level of demand at different nodes of network. The nodal prices so arrived at can be used determine transmission charges to be recovered from demand nodes as the difference between the weighted average cost of generators scheduled and the price at a particular demand node. Simultaneous disclosures of the information about generators, which have been "constrained-on" (asked to operate despite being costlier due to congestion) and "constrained-off" (asked to back down despite being cheaper) due to network constraints, will help is strengthening of network as well as location planning for generation and consumption. To simplify the implementation of the last component the transmission charges for the last element can be also worked out in a relatively static manner and for different regions/zones if the flow patterns do not change frequently. The latter approach of regional/zonal pricing based on typical flow patterns can be easily integrated with capacity cost allocation to determine a simple and static transmission pricing. Such pricing, once computed, will have only two components except for any specific asset required for a set of beneficiaries- (a) scaling factor linking percentage of transmission costs to be absorbed in a region based on percentage of throughput/peak demand in that region, (b) percentage of losses and congestion charge for that region linked with the percentage of throughput/peak demand in that region. These can be specified for different ranges as well. For example, the losses may be different for different levels of throughput/peak demand in a region.

To sum up, the following may be issues in going forward on transmission pricing issues-

- There is a case for incorporating costs associated with transmission network expansion or strengthening to be factored in while evaluating the cost of adding new generation capacity at alternative locations. These costs should be borne by the beneficiaries of those who are going to consume the power from that capacity.
- Some proportion of the capacity costs (capital and O&M costs) related to other existing transmission assets should be allocated based on some distance related measures based on typical or average flow patterns on the network given loads and generators. Load flow studies can help in approximating the average load. Some proportion of these costs should be recovered from all consumers as network also enhances reliability for all consumers and its function is not limited to evacuation of power.
- Losses and congestion costs should be recovered at different levels from different nodes or zones depending upon the marginal loss induced by increase of load at that node or in that zone. These can be computed dynamically using load flow software or if the load flow pattern does not change significantly over a period of time, the basis could be typical load flow pattern. These charges can be reviewed as and when the load flows are expected to change due to addition of generation capacity, network changes or changes in demand pattern across nodes/zones.

5.7 Competition among Distribution Companies

State Governments want Uniform Tariff

Some states which had already unbundled the sector even before the enactment of the Electricity Act in 2003 along with some others, which have since then done so, opted for creation of multiple distribution utilities within the state instead of a single distribution utility. This, in principle, could have facilitated competition among them in terms of operating performance if not for consumers and the market. In reality, things have turned out to be different in states where all the distribution companies are owned and controlled by the State Government. There are two factors, which have resulted in practice entities not competing in terms of providing benchmark to each other but merely technical and legal separation. Firstly, administratively these entities have been unified by the State Government with common directors on boards, direct engagement of State Government officials in the board or as the CEO, centralized human resource policies including transfers etc. (in some cases by the Government and in some others, by the centralized residual SEB). Secondly, the State Governments have

been sensitive to keeping tariffs uniform in the entire state despite differences in consumer mix or operating performance of a region of the state or the utility. The State Governments have been resorting to dynamic capacity allocation to change power purchase costs for different utilities keeping it lower for adverse consumer mix (more agriculture or rural) distribution utilities and higher for others. In this process, the pressure on utilities which would have shown poor performance has been eased through lower purchase cost and higher subsidies thereby lessening the incentives for reform. States such as Assam have been thinking of merging multiple distribution utilities created earlier. The absence of multiple licensees and lack of competition among them also makes intra-state ABT envisaged in National Electricity Policy and declared by various SERCs less meaningful as the entities realize that ex-post settlement through power purchase cost would neutralize any gains or losses through intra-state ABT.

The way forward

It is clear that unless the State Government wants competition among its distribution companies in terms of performance and wants to create pressure on them to deal with adverse consumer mix related problems and wants to limit the subsidy available to the utility, it is difficult to promote competition among various utilities for better performance. If the States have the will and are ready to allow each utility to show results and face the consequences, only then can effective competition emerge. These issues are also related to allowing competing and multiple distribution licensees within an area, as enabled in the Act. The following measures would be required if the competition within an area and across a State has to emerge. The political will of the State Government to let distribution companies compete in terms of performance with only board level influence as the Shareholder. This may entail fixing capacity allocations, subsidies and other support in advance for many years and to allow them to show results based on their performance. The upfront allocations can be done to minimize tariff variations within the State but not necessarily being exactly the same. With abolition of freight equalization schemes, the public has learnt to accept small variations in prices at different locations.

5.8 Competition through Captive generation

Provisions in the Act and the Objectives

Section 9 of the Electricity Act clearly allows any captive generation plant to either construct dedicated transmission lines or to avail open access to existing transmission lines subject to availability of adequate transmission capacity as decided by the CTU and STU. In case of any dispute, the concerned ERC has to adjudicate whether adequate transmission capacity exists or not. The Act also

liberalises the definition of captive generation as capacity created by an entity, or a co-operative or an association of persons for self-use.

The objective of the Act was to create competitive pressure so that the utilities do not load such consumers (industrial) with high cross-subsidies and arm twist them for the use of network in case they required to . These objectives were set in a context where large number of industrial users in power-intensive or power-critical industries had already created captive capacities to avoid high cross-subsidy built in tariffs and to improve the quality of supply to their units. Most of these were located close to the unit, which even if sub-optimal from the point of cost of generation, avoided use of network. Most of these also were hooked on to the network for using and injecting power from and into the Grid. Typically, the terms of injecting power were not favourable as they did not have any bargaining power vis-à-vis the utility.

The Reality Today

Captive power in India in terms of installed capacity is estimated to be more than 17-18,000 MW. While most of it may be not available for the Grid, the standby capacity can be used in the Grid to some extent. For that the key issue is open access and in some cases, the transmission tariffs. The open access issues are intimately linked with the attitude of the State and the independence of system operator (RLDC/SLDC), which has been discussed separately in this section. The other important issue at times has been the nature of transmission tariffs. In case of a postage stamp transmission tariff, the captive capacity has to pay for the cost of the entire transmission system for taking the power even across the road! In a specific instance in Gujarat, the STU demanded the same from a captive generator for taking the power for self-use across the road. Of course, the Act provides for dedicated transmission lines but constructing such line(s) in turn requires obtaining right of way and approvals for crossing a public road from the State Government. If the State Government is not supportive or refers the same to STU, the bargaining power of the state-owned utilities (and STU) comes to the fore. The case of Nava Bharat in Orissa where the SLDC refused open access is another example discussed later in the report.

Despite not very favourable environment for using captive power and allowing open access, there has been some success as well in using captive power to overcome energy shortage in Pune. In a unique experiment initiated by the CII Pune, a mechanism was evolved by which the city of Pune was relieved from load shedding since June, 2006. This project did not evolve any extra allocation from the grid nor did it put any financial burden on the State. It was an innovative mechanism by which the energy shortage was met through generation /

consumption by leading industries in Pune through their captive / stand by generating sets. The citizen also benefitted through zero load shedding and paid for this facility. The use of captive power capacity in case of Pune was possible as the express feeders supplying to industry were exempt from load shedding which had idle captive capacity assessed to be of the order of 90-100 MW from around 30 such CPPs. The costs of generation from these units was of the order of Rs 8.5-11 per kWh. Since Maharashtra was having shortage of electricity and MERC had declared load-shedding in all areas categorized under six categories based on AT&C losses, Pune was having load-shedding of 3-4 hours every day. Under this initiative, costly CPP power was used to supplement the available power. The consumers of certain categories, as approved by the MERC, were charged an additional Rs. 0.42 per kWh in addition to the tariff approved by MERC for the MSEDCL distribution areas. This worked for a while (for about 3-4 months) but since the fuel costs of CPPs went up and the power shortage increased, and because in reality the CPP capacity made available was only 50-60 MW. In the second phase, as the energy shortfall increased in Maharashtra, a tripartite arrangement has been worked out between a trader, distribution company and a franchisee was worked out to supplement the power in the area by buying costly power for the area covered in Pune and the same was allowed as “reliability charge” by MERC. The above experiment, while not completely successful in meeting its initial objectives, pointed out a few key lessons-(a) that it is possible to use CPPs provided there is a framework for them to recover costs; (b) that consumers are willing to pay for quality power; and (c) that tariffs can be linked with the quality of supply.

The Way forward

To encourage captive capacities being created optimally and to use them for peaking power, the key issue is that of open access and the required framework for the same. Some of the measures required for achieving open access in the spirit of the Act have been discussed elsewhere in the report. Some of the specific measures required for captive capacities are-

- Review of all captive capacities, which have agreements with the SEBs or utilities by the ERCs to make sure that the terms are at least as favourable as alternative sources of power including ABT.
- Encouragement by the SERCs and the State Governments to use captive power for peaking load and meeting energy shortages in line with “Pune Model”. Despite limitations of the Pune model, utilization of idle captive capacities is desirable as the alternative entails addition of new capacity, which may be wasteful for peaking power if required for very short periods.
- The direction over longer term is clear enough. Open access must become a reality for all consumers above 1 MW, and captive must be allowed to participate through open access. They should also be allowed to participate

in the UI market. In the longer term as the UI/ABT is replaced by spot prices, the captive like all others must be allowed to participate in the spot market.

5.9 Competition through Multiple Distribution Licensees

Provisions in the Act and the National Electricity Policy on Multiple Distribution Licensees

Under Section 14 of the Act, licences can be given to two or more entities for supplying electricity in the same geographic area. The National Electricity Policy states that the smallest unit of area could be an urban area defined by municipal council /corporation or a revenue district. With the smallest area so defined, there should have been much interest in getting into distribution.

No Second Licensee in Reality

In reality, there has been no interest in acquiring second licence in any area despite defining the smallest area in the policy at an attractive enough level so as to avoid adverse consumer mix areas and associated problems. There have been two major reasons for no one evincing interest in second distribution licence. Firstly, unlike transmission utility and open access provisions in the act where the wires of have been opened for any eligible player or consumer to access, there is no such provision for the second licensee. In other words, any such licensee would have to develop its own network, which is costly and is not even desirable from the point of social costs. It is defensible only in cases where the distribution system has not been developed by the existing licensee despite having the license. It can also happen in cases where the state of the system is extremely poor and it may be better to develop the principal distribution network anew through a party other than the incumbent. The Act, it seems, consciously has envisaged the entry of players for cases only. The competitive pressure on an existing utility is also envisaged through the “trading” route whereby any trader can effectively act as supplier and can use the open access provisions to compete with the existing utility without creating its own network or without assuming USO obligations.

The second reason for lack of any interest in areas, where the incumbent is a state utility, is that the competition is not seen on even playing field with STU/SLDC being part of the State Government. With perceived symbiotic relationship between distribution utility and other arms of the State Government entities, the advantage is seen to lie with the incumbent utility. This is also one of the important reasons for traders not competing with the existing utilities as “suppliers” even if open access is allowed and the surcharge is low.

If competition in distribution were to be realized as envisaged in the Act and the National Policy, the following steps may be required-

- Allowing access to wires and distribution system to competing distribution utilities for the use of their assets at a charge which compensates them for their investment and provides adequate return. This, however, mean computing wheeling charges for each area where competing licensees are allowed. This would mean variation in end consumer tariffs within a state unless subsidized by the State Government. For that, there has to be political willingness on the part of the State Government.
- The State Government has to be seen as supportive of competition with its own utility and should be able to accept variation in tariffs across State. The independence of STU/SLDC has to be signalled credibly by having only arm's length relationship between them and the State Government and with distribution utility.

5.10 Reduction in Distribution Losses

Starting with realization in mid 1990s that the distribution side is the weakest link in the sector with AT&C losses of more than 40%, one of the major objectives of the reforms has been to reduce these losses so that overall viability of the sector can be improved for attracting investments. It is obvious that without adequate revenues coming from the end consumers either the state would to continue investing in the sector or would have to be ready to provide guarantees to the private sector for them to create capacities upstream. On the distribution side, it was realized that the problems were twofold- (i) high unaccounted for energy (commercial losses), and (ii) high technical losses due to poor state of the distribution system due to lack of resources and organizational weaknesses.

To address these, in early 2000s, the APDRP - a programme of the central government which was in the nature of performance budget- was created. Essentially the programme made available funds to SEBs /DISCOMs to improve the technical aspects of their distribution network, meter extensively the same, and improve consumer values. Linked to the disbursement were targets for reduction in T&D and AT&C losses, raising revenue per unit of input and such other defined measures. MOUs were again signed even at the circle level and the central government set up professionals to monitor the progress at the circle level. States could hope to win large grants if they showed substantial improvements.

In the Electricity Act 2003 too, under section 55(1), it is clearly mandated that "No licensee shall supply electricity, after the expiry of two years from the appointed date, except through installation of a correct meter in accordance with

regulations to be made in the this behalf by the CEA". Similarly, the Electricity Policy clearly states that while reorganizing the SEB, distribution utilities so created should not be burdened with past liabilities and need to have a clear road map to restore the viability of distribution utility by reducing losses. Clearly, the need for reducing distribution losses- both commercial and technical has been the cornerstone of objective of any reform initiative in the sector. The elements envisaged are also amply clear- 100% metering, energy accounting and identification of feeders and consumers (where losses are high), incentivising and facilitating measures to control theft and losses at various levels.

The Impact and the Reality Today

Under the APDRP, the AT&C and T&D losses defined on the energy flows outside of agriculture were closely monitored. The flows to agriculture being determined through an assumed /estimated drawl per HP of pump capacity connected in a certain distribution territory. Realized improvements varied across states, but nearly all circles showed some improvements in terms of reduction of technical losses since the physical distribution network could improve, new transformers replaced and portions of the network that were old repaired.

But the non-technical losses, despite the provision of police powers to DISCOMs under the new dispensation (state acts or through the EA2003), reduced only in a patchy way and that too in the larger cities where the confounding effect of agricultural supply /drawl was less of a concern, where revenue implications were higher and where political interference is usually less due to media glare. In many areas the savings of energy made on account of technical improvements only meant greater financial losses since no attempts were made to reduce or cap the supplies to the agricultural sector. Agricultural metering also a part of the APDRP did not make much progress and even where it did, the meters were not necessarily functional. With the vast amount of data flowing in from meters of consumers, transformers, feeders and substations, the MIS in SEBs /DISCOMs improved somewhat but not substantially enough to give true control over the business. Most ERCs and DISCOMs whom we met do not have confidence in the reported T&D losses. There are problems of NA/NR (not available / accessible or nor read) and defective meters even when there is metering. This result in billing on the basis of assessed consumption and can be easily used to transform on paper theft into collection problem and vice versa. The energy accounting and billing system is not integrated at most states and hence it is difficult to pin-point problem areas more precisely. We also came across states where the feeder level meters are reported defective and meters being not read. The only way out for this would be automated meter reading at least up to 11 kV level.

Many states in order to control and limit the flow to agriculture without hurting rural household supply carried out extensive feeder separation programme. This had been part of the APDRP, and states like Gujarat took the matter to its logical conclusion by separating all agricultural feeders and building new feeders called JGY feeders to take power to the rest of the village. This gave the managers some control over the network and staff could be called upon to account for losses in non-agriculture in a more meaningful way. Some other have implemented Feeder renovation program and have made use of technologies related to cables and equipment like use of ABC, HVDS or RLMS on pilot or extensive basis. Most of the States keen on reform and as per the objectives of APDRP have implemented metering at up to 11 kV feeders level and have done almost complete metering of end consumers other than agricultural connections. These states have also progressed in outsourcing and improving collections, meter readings and call centre support for consumer complaints. There has been some progress in consumer indexing as well. Some have installed SCADA at major urban centres.

Overall T&D and AT&C losses after having come down nearly all over India by 5 to 15%, but have not fallen further except possibly in a few states. Over the same period many state governments have been making good in part or full the losses as 'direct' subsidy payments to the DISCOMs/ SEBs in the form of cash/ excise subventions. Thus there has been a slow but significant shift of the losses on to the budgets of the government since the capacity of the state system to internalize the losses has only been falling as erosion of net worth has taken place. Reform in some cases meant reducing subsidies even as the government focused on fighting theft. The idea in that the supplies to agricultural sector would be limited to a certain number of hours every day. And for the rest of the electricity sector the officers of the state DISCOMs were held accountable. In such a situation it is possible that the managers through supply of less than the stated hours, or by restricting in many ways (transformer failures, line fault) the actual drawl of electricity could enhance the flows to other segments to show both loss reduction and improvement in the financial realization. The improvement via theft reduction in the urban areas would have been more difficult. In fact, if load-shedding were not resorted and all the consumers were to get 24 hours supply, the losses-both physical and commercial would be more than at present.

The pressure from regulators to reduce the losses has worked weakly at best. This is not to deny that most regulators have in their tariff orders generally sought to put targets on T&D /AT&C loss reduction. Such targets were not only not seen as binding by the regulated, but there was little that the regulator could do if the targets were not achieved other than imposing financial penalties. In any case, if the State owned distribution entities refused to do much about reducing losses and metering, there is little the regulator could do since his weapon of de-licensing the entity would have been quite incredible. The only other weapon of financially

penalties in any case is not very meaningful due to lack of commercial interest as far as state-owned distribution entities are concerned.

Current subsidy cost is over three to four times the benefit that farmers actually enjoy and find useful. This means if the subsidy were delivered in a non-distortionary manner, vast savings could be realised. Unless the marginal use prices to the farmer are reflective of true costs he would not use electricity with care, and his demand would be infinite or very large and so rationing, with all the ills would be involved. Thus in 8 hours supply, the entire agricultural network is used only for a third of the time, inflating the capital cost three times. Similarly the wires have to be of much higher capacity since when there is supply on a feeder for 8 hours, the flow gets concentrated in that period, also increasing line losses. The price difference (price based subsidy) means that even in principle, there cannot be accountability to revenue, since the revenue implication for the same amount of energy is variable depending upon the load from the various tariff categories. The arbitrage between low (zero) price of electricity and higher priced electricity to other consumers allows utilities to hide theft and diversion. This is at the root of the governance problem at the lower levels in SOEs. Connivance and hiding theft and diversion is rampant. Systematic metering in a tree like fashion from the substation downwards to the transformer is no solution either since there is no accountability, unless feeders for every category of consumers are separated and there is instantaneous reading of the meters down a feeder. This would involve impossible costs. Already the feeder separation and associated metering down the line expenditure of the Gujarat government for instance is over Rs. 12,000 crore, of which at least Rs. 9,000 crore is avoidable and only a 'perverse' response to the perverse situation caused by tariff distortion (that can and needs to be corrected). The annualised cost of this ignoring maintenance and O & M costs is about Rs. 900 crore a year. This along with the subsidy grant of Rs. 1500 crore given by the Gujarat Government is a whopping Rs. 2400 crore for subsidising the farmer. The true benefit they get would be no more than a third of this amount.

Yet the activity of feeder separation, excessive metering, massive investments in IT, HVDS and one transformers for each farmer are 'privately' profitable while being a humongous social waste.

The Way forward

We first deal with the immediate changes that need to be made. Next we bring out the measures that would truly liberate the sector from the distortions caused by price-based subsidisation. This is one of the most important and vexed issue as far as reforms in the sector are concerned. It is clear that despite substantial measures initiated at the central level to reduce commercial losses and to incentivise and

enable the State Governments to focus on the same through APDRP, provisions in the Act on theft and special courts, unless there is political will at the State level the attainment of this objective would be difficult. Over a period, electricity has been converted into a “public good” through political interventions, even though it is essentially a private good. Changing the behaviour of key constituents the other way is not easy and requires extensive enforcement support and political will for the same. While some states (AP, Gujarat, WB, Maharashtra etc.) have made attempts in that direction, most others have not felt the need as strongly. Practically all have focussed on areas or areas which are critical from the point of revenues and politically least sensitive such as larger cities or HT/Industrial consumers. Even while leaving agricultural connections unmetered, the states could do the following-

- To start with, there is a need to have consistency across time-periods and utilities in the way the distribution loss and efficiency measures are computed and reported, which is currently not the case. Transmission losses need to be separated from distribution losses. Currently, the magnitude of distribution losses is not clear with AT&C loss being end product of technical losses, commercial losses and collection efficiency. While reporting input and realized energy, traded energy should be excluded as it can bias the measure and technical, non-technical losses and collection efficiency need to be separately measured consistently. One of the problem area in this in the presence of billing on assessed basis.
- Regulators have yet not been able to either form baseline estimates of all the three relevant measures of efficiency in most cases or do not have confidence in the same. Greater thrust on the same is required by segregating technical losses through first estimating technical losses feeder wise through simulation or through feeders having no commercial losses and then subtracting it from AT&C loss to arrive at a product of commercial loss and collection efficiency.
- The feeder level meter readings should be automated. Gujarat and Rajasthan have reportedly completed AMR (automated meter reading) for feeder level metering. There is a need to reduce and monitor defective as well as reported NA/NR readings. The energy accounting system should be integrated with billing system.
- The economics of use of AMR needs to be worked out for large consumers. It might be more effective above certain connected load to have AMR for such consumers than current system. Once determined, a time bound program should be mandated for all utilities to resort to AMR for such consumers.
- Linking quality of supply (including load-shedding) with the losses and collections on a feeder. Even though the policies spell it out, ERCs and the State Government have not attempted this linkage. Obviously, such a measure requires political will but with the support of ERCs, this linkage can be and should be implemented. In fact, an order by MERC (Maharashtra) requiring higher load shedding for consumers of high loss areas was legally

upheld. Such measures may create strong social pressures on defaulting consumers or those who indulge in theft/unauthorized use. MERC has also allowed reliability charge to recover cost of procuring costly power for quality power in Pune, which is also an effective way of differentiating tariffs for quality of supply.

- Initiatives like feeder separation for agriculture, use of ABC conductors and HVDS system have been able to reduce losses and are economically viable if introduced based on the characteristics of the load and consumer profile. Selective use of these may be required to create new possibilities for loss reduction.
- Supporting stringent measures on theft and creation of Special Courts as provided in the Act. Even though the Act provides for stringent measure including criminal and civil liability in cases of theft, the State Governments have not been too keen on the implantation of these provisions across the board. Some have informally told the distribution utilities to not initiate criminal measure for the first time defaulters.
- Stronger linkage of rewards and punishment of distribution company's employees, engineers and managers with the losses for the areas under their control. The linkages currently are weak and given the extensiveness of the problems, the utilities have limited degrees of freedom. In a state like Assam, the average age of employees is 54, due to lack of recruitment for several years and to expect too much effectiveness from such measures is unrealistic. Nonetheless, it is difficult to envisage the improvements without such accountability. Similarly, there is a case for implementing MYT framework to incentivise loss reduction for the distribution utilities.
- Another way out is to create competition through multiple licence, open access and captive generators so that it creates enough pressure on the distribution utility to reduce losses and improve efficiency. The experience of Maharashtra in select areas where private entities were handed over distribution on behalf of the distribution entity as a franchisee also points at the possibility of using private entities in reducing the losses provided state is willing to provide enforcement support.
- It goes without saying that for all this to happen the State Government not only needs to have political will but would have to create governance structures to minimize / eliminate political interference in the sector despite temptations to do so off and on. In fact, the least that the state government and the local governments can do is to timely pay the bills as across the states, the payment from them remains outstanding for considerable periods of time!
- Some of the state governments have policies, which are still reflective of the mind set of treating utilities as non-commercial entities despite corporatization and unbundling. These include policies on procurement where the utility is expected to give preference to or have certain %age of

order going to entities located in the state (for example, Gujarat). The evaluation of bidders is also done on pre-tax basis. The costs associated with such policies in the form of higher prices/taxes paid by the utility are ultimately borne by the consumers and such policies need to be reversed. The regulators also need to protect the consumer interest in such cases even though such initiative can be undermined by issuing policy direction under section 108.

- Another example of such type is non-filing for tariffs by state government utilities (Tamil Nadu) or by filing tariff with ARR based on no/low returns (Haryana) on equity. Such policies or interventions are against the viability of the sector and better way of subsidizing would be by paying subsidies to the utilities or consumers rather than subverting principles of commercial operation of the sector. The only workable solution would be direct subsidy to the farmers with the price of electricity going up to the cost to serve.
- Current price based subsidies should be replaced by direct subsidies to customers who are subsidized. This is absolutely necessary in the case of farmers in their use of IP sets.
- Direct subsidies can be provided by endowment transfers to each electricity-using farmer which can be fixed upfront. With the transfer (coupons, credit on a chip card or credit card, or a specially designed electricity access card which goes on a meter) the farmer can buy the electricity he needs up to his endowment every month. For consumption over his entitlement he pays at the regulated rate which is the cost to serve (price cap). Hence the allocative price for his decision to use electricity is its true price.
- The endowments are made tradable between farmers and across time and are also discountable by the government at current rates of tariff (minus a small discount cost).
- The DISCOM collects the coupons or the credits on chip/ credit cards that are transferred; besides cash payments made by farmers and other consumers and the total constitutes the revenue earnings of the DISCOMs. The coupons /transferred credits on chip cards are presented to the government for cash transfers by the DISCOM.
- Once identification and issuance of access cards/ chip cards/ credit cards is made, the disbursement of subsidy can be put on autopilot through a private vendor (typically a credit card operator or a mobile phone service provider) at a cost no more than a few percentage of the total subsidy transfer by government
- The current HP of the IP set with the farmer times a certain standard of drawl per HP can approximately be the first announcement of the subsidy due to the farmer. The same after due scrutiny and constrained by village level information on actual power drawn over the last year, and adjusted for land use and rainfall, after subject to challenge through the use of private information (information available with each farmer about other farmers) can be put down as the entitlement for the particular farmer valid over the next 10 years.

- The programme to transform all current price based subsidies to endowments /entitlements can be announced at the state level to enhance the political gain from the move since the farmers in standing to make real gains would lend support. If the programme is credible and well structured the resistance to metering would not be there. It is important that such as campaign should have the support and acceptance of farmer lobbies and political groups.
- States can lay out the current spending on subsidies plus over half the cross subsidies as the total endowment. This would enhance the benefit to farmers while all the distortions in price based subsidies go away. Once the current subsidies are so defined they are capped in energy terms and should increase only to the extent the cost of power goes up. Thus over the longer period the cost of subsidization would be small part of the total cost of supply since demand of unsubsidized electricity would steadily go up.
- The current ballooning expenditures in feeder separation and the very large distortions in water and electricity use can be overcome. Most importantly such non distortionary system that can make feasible management control and accountability within DISCOMs is vital for overcoming the governance failure.
- The same would also be politically rewarding since the farmers would actually gain significantly over the current system.

5.11 Prompt payment of Subsidy by the State Government

Provisions in the Act and National Electricity Policy

Section 65 of the Act provides for the State Government to pay promptly and in a manner specified by the SERC , any subsidy declared for any consumer or class of consumers to the distribution licensee. Even though section 108 provides powers to the State Government to give directions to the utility, yet section 65 explicitly states that notwithstanding any such direction under section 108 the State Government has to pay subsidy according to the ruling of SERC. The Electricity Policy in addition to emphasising the need to make advance payment to the utilities as per the section 65 of the Act also mentions that each category of consumer should also pay at least 50% of cost of supply.

The Reality today

Despite section 65 of the Act, several State Governments have not been making payment in advance to the state-owned distribution utilities. We came across one instance (Karnataka) where reportedly section 108 directions were given

on subsidy payment despite explicit provision in the Act that such direction cannot be issued in conflict with section 65 of the Act. In fact, most of the states do not have to issue any such directive as the state-owned distribution utilities are unlikely to complain to anyone including SERC for non-payment by their owners! Unless ERCs were to insist by demanding proof of payment, there is no one to bother. Some of the states have also adjusted their subsidy payment against the outstanding loans due from the utilities on account of past liabilities transferred to the state governments as part of the recommendations of the Ahluwalia committee report. This is against the stated policy objective of not saddling the distribution utilities with liabilities of the past. While the subsidy payment promptly may not affect much the reforms per se, prompt and advance payment of subsidy helps utilities in financial terms and also bring about a certain discipline in the state's decision to subsidize based on its own financial condition. Also by not limiting the subsidy to 50% of cost of supply and along with reluctance (and difficulty) in metering all consumers, it weakens the spirit of reforms. The metering issue and resultant problems in energy accounting are dealt with elsewhere in the report.

The Way forward

To bring about the kind of discipline envisaged in the Act and the Policy, it is unrealistic to expect that the state-owned utilities would insist on advance payment and the State Government on their own would make such payments. The only way out would be to:

- Empower further the ERCs to insist on demanding proof of payment (by the Government) from the utilities and change the tariffs accordingly if the payment has not been made. This, however, may be difficult in current scenario as SERCs do not feel empowered enough and besides imposing penalty on the utility, have limited means of enforcement to ensure that utilities charge tariffs as specified. This can also set them on a course of collision with the State Government.
- Alternatively, there can be another structure which can be put in place by the Central Government through policy backed by monitoring, which incentivises limiting subsidies and prompt payment of the subsidies.
- Paying utilities for the subsidy cost is necessary in the context of price based subsidisation. But this does not solve the problem of distortions both on the user side and on the side of the utilities. Thus waste at the level of farmers, rationing with all the attendant evils and arbitrage situations that create rents would continue. Utilities would have strong incentives to over claim the subsidy since there is no independent verification of the subsidy cost possible. Therefore the first best solution to the subsidy problem not envisaged as of now in the Act or policy framework is “direct subsidy” (as outlined earlier) to the intended beneficiaries.

5.12 Independent STUs and SLDCs

Independence of STU and SLDCs is critical for competition

Wherever competition in generation or supply has been envisaged and attempted in the sector, it has been with the recognition that the transmission network and “wires” should be available to all the competitors on a non-discriminatory basis. For this purpose, the sector needs to be unbundled with transmission and system operations separated from other activities in the sector. The Electricity Act 2003 and reforms in India have also recognized this by structurally unbundling the sector with independent CTU/STUs as transmission utilities and NLDC/RLDCs/SLDCs as system operators.

For any kind of competition to emerge at the wholesale level, the transmission network has to be owned and managed by player(s), who have no commercial interest in the competitive market. The same is true for distribution network for competition at the consumer level. The network operator cannot exercise any kind of bias vis-à-vis buyers and sellers. His behaviour has to be governed by the need for energy balance, system reliability, assurance of control (and other similar objectives) being met on real time basis. Subject to these objectives and constraints, any commercial outcome should be as good as any other for the system operator. Any such ISO requires complete control over the network and should be able to issue binding instructions to dispatchable entities (generators and loads) even though it may have no commercial interest.

Without independent transmission and system operator, it is not possible to have effective competition in the sector as it is well-known that the system operator and transmission can easily affect the outcomes and distort the competition in favour of the competitor whom it colludes with. In the Act and the policies this aspect has been kept in mind. For example, the National Electricity Policy states that CTU/STUs/RLDCs/SLDCs need to provide all intending users information on the transmission capacity and load flow studies. Nonetheless, these intentions have not translated themselves into effectively independent transmission utilities or load dispatch centres.

The Reality today

In India, currently the system operators (RLDCs/SLDCs) are only involved in scheduling and dispatch decision and do not have similar control. More importantly, they are not truly independent of the entities which have commercial interests (DISCOMs and generators) due to historical reasons. And since much of the sector consist of state-owned entities, and the personnel manning the SLDCs are drawn (typically on deputation) from these SOEs or their successor entities

behaviour and actions that could go against the interest of SOEs in generation and distribution are abhorred.

States that have, unbundled and have not sought extensions for implementing the Act, have also declared separate entities as STU and SLDC as required under the Act. But while separate entities have been created in line with the letter of the Act, the newly created STU and SLDC have not been kept at arms length from other state-owned entities in generation or distribution as would have been appropriate with the spirit of unbundling and the Act. In almost all cases, there are direct linkages structurally or mechanisms for all state-owned entities to coordinate under the power/energy ministry. In some cases (for example, Karnataka), the MD of STU is the Chairperson of all distribution companies. In some others, the residual SEB (for example, Gujarat) is the coordination mechanism across entities created post unbundling. In some cases, personnel can be moved from one entity to another essentially meaning that they conceive of their roles not in any particular entity but as part of erstwhile SEB. The creation of multiple entities is seen as fulfilling just the technical requirements imposed from above and mitigated by various coordination mechanisms. This clearly is violation of the spirit of Act, and would not have been possible had the entities been privately owned. The unfortunate consequence of the above has been that the STU/SLDC have been sympathetic to their sister distribution utility and interest of the State Government in matters related to open access and competition. As mentioned earlier, in quite a few cases in the beginning STUs cited transmission capacity constraints when open access applications were filed. In case of SLDCs also, they are not perceived to be independent entities. This was affirmed in case of Orissa, where SLDC and Orissa Power Transmission Corporation Ltd. (the STU) denied M/S. Nava Bharat (to sell its captive power to M/S. Reliance Energy Trading with end customer being Andhra Pradesh Utilities) open access not because there was any congestion in the system but because GRIDCO (Grid Corporation of Orissa), another state utility on the basis of opinion of Department of energy, Government of Orissa was of the opinion that such surplus power ought to be sold to the State at the rate fixed by OERC. It was brought out by M/S. Nava Bharat in the case before CERC that GRIDCO independently was interested in entering into an agreement with them for sale of surplus power which they denied. In effect, this case shows that the Orissa SLDC and STU did not act as independent system operator despite OERC's orders. Finally, the CERC had to intervene.

The Way forward

To promote independent system operations, which is key to promotion of competition and realization of any benefits from competition and open access, several measures may have to be initiated. Despite these measures, the stance of the State Government is going to remain critical unless all the downstream and upstream entities are in the private sector, an unlikely scenario for most states.

- The State Governments have to let go at least the STU and SLDC as part of their administrative framework of Ministry of Power and Energy. Organizational and reporting structure for these entities, ideally, should be different and they should have no KPIs other than reliable and secure system operations within the framework put in place by the SERC.
- Ring-fencing STU and SLDC may require administrative, financial and organizational changes so that they can operate independent of the other entities purely on technical and operational considerations without any commercial and geographic interests in mind.
- Manning of SLDC is critical in terms of training and protecting them from ire of any other entity and they should be completely accountable internally or to the SERC. Extensive training for independent system operation, setting up means of coordination and control and equipment for achieving the same should be taken up urgently as it is critical for effective and efficient functioning of SLDCs.
- The data on transmission system capacity, load flow studies and decision-rules for determination of “non-discriminatory” open access should be displayed on the web-sites of SLDCs on real time basis, wherever required.

5.13 Privatization Models

Orissa’s Sale of 51% Equity in DISCOM

Even though today it is evidently unsuccessful model, for the sake of completeness we review the features of Orissa’s attempt to privatize distribution. After initiating reforms process by unbundling the sector and constituting the OERC in 1996 whereby the OSEB was unbundled into GRIDCO (Grid Corporation of Orissa), Orissa Power Generation Corporation (OPGC) and OHPC (Orissa Hydro Power Corporation), the state embarked on privatization of the sector in the state. This unbundling process resulted in up valuation of assets with entities as compared to the values on the books of OSEB. In 1998, 49% of the equity stake in OPGC was sold to a private operator, AES, at Rs. 603 crore. The entire distribution system of Orissa was divided into 4 distribution companies as subsidiaries of GRIDCO in 1996 itself. In the absence of clear separation and accounts of each of the four DISCOMs and to quickly privatize, initially short-term distribution operations agreement (DOA) approach was followed wherein the investments were to be made by GRIDCO but the private entity (in this case, BSES) was expected to provide key managerial staff. The approach failed and the contract had to be terminated as GRIDCO felt that BSES failed to perform whereas BSES felt that it had no control over the organization and employees. Based on this experience, it was decided to sell 51% stake of DISCOMs to private players based on competitive bids. Prior to bidding, the tariffs were determined by OERC at 35% T&D loss level

against the request of 41% by GRIDCO. Very few players bid for the privatization in 1999 and for three DISCOMs, awards were made to BSES despite initial condition of not more than 2 DISCOMs per player and one distcom went to AES outside the bidding process as there were no bidders. The private players in the very first year 1999-2000 realized that the billing in the DISCOMs was only 44% of input energy and collections were meagre at 77%. The state government post reforms stopped paying subsidy, realized funds from sale of its stake in OPGC and the government departments continued to delay payments. The unsustainable losses resulted in liquidity problems for the DISCOMs which stopped payments to GRIDCO, which in turn delayed payment to generators.

Delhi's Privatization Based on Bids for AT&C loss Reduction

In case of Delhi, the state government first unbundled the erstwhile DVB (Delhi Vidyut Board) into one generation company, one transmission company and three distribution companies all under a holding company, which will hold equity in all these companies. Delhi privatization of the three DISCOMs in 2001, entailed the bidders bidding for AT&C loss reduction with the winning bid of highest loss reduction over five year time-frame getting 51% equity stake at face value. Under its policy direction, the state also declared that all three DISCOMs would charge same retail tariffs till 2006-07 and the tariffs determined would be such that the distribution licensees would earn at least 16% provided they meet their loss reduction commitment. The government also provided a loan of Rs 2600 crore to cover the gap between its revenue requirement and the revenue it would get from the DISCOMs based on bulk supply rate tariff to be determined by the DERC, constituted before privatization. The methodology for bulk supply tariff ensured the revenue requirement of DISCOMs would be met (by fixing the power purchase costs) and the gap would be with the Transmission Company, for which the loan was being extended to it at liberal and negotiable terms by the government. During the process of bidding, it also clarified that there would be minimum loss reduction for each year and the gains from loss reduction over committed reduction would be shared 50:50 between the utility and consumer. During the bidding process, finally only two bids were received. One bidder had bid for all three and another for two DISCOMs. All had quoted less than minimum commitment specified. Subsequent to renegotiations, the bidders increased their commitments with some minor adjustments in terms and conditions of the agreement and all the three DISCOMs were offered with commitment of AT&C loss reduction of 17% over five years. The DERC had already declared opening AT&C loss figures, which were 48.1% for two DISCOMs and 57.2% for the third one.

By the end of 2006-07, all three DISCOMs were able to reduce AT&C losses to the target levels, including for each year (except for the first year in the DISCOMs with highest loss level). While one private player reportedly reduced loss levels very close to the targets, the other one reduced it by a fairly wide margin from 48.1% to 23.54% in 2006-07. In the very next year 2007-08, that player has been

able to reduce it further to 18.44% level. DERC has set the loss level to be reduced further down to 17% for two DISCOMs and 21% for the third one by 2010-11 under MYT tariffs. Though there were initial complaints about the quality of supply and fast meters etc., yet by and large the privatization in Delhi has been able to improve the network, reduce losses and reduce the burden on the state. Delhi DISCOMs, however, are still not near the performance regularly achieved by the private utilities, which have been operating as licensees for long, in cities like Mumbai, Ahmedabad, Surat and Kolkata in terms of loss levels.

Karnataka's Proposed Distribution Margin Approach

In 2002, a report by a consultant appointed by the Karnataka Government came out with a similar approach for privatization of distribution utilities. The state had already unbundled the sector in 1999 and constituted the KERC. Under this approach, there were to be two components of revenue to the distcom- (i) base revenue, and (ii) incentive charge. The base revenue would be, the amount retained from gross revenue receipts adequate to cover the cost of operations and a low return on equity. The base revenue would be allowed to be adjusted for any risk created by or controlled by the state government. The operator had to collect certain minimum gross revenue otherwise there would be a penalty. In case the operator was to collect more, there would be an incentive charge payable as percentage of additional revenue. The bidding would be on the basis of minimum incentive charge and all other revenue requirements would be determined by the regulator under a MYT framework. The winner would have been awarded 51% of the equity of the distcom. Due to difficulty of estimating baseline numbers, and in implementing MYT, moral hazard and contractual disputes in risk shifting provisions, the proposal was not favoured by the KERC and eventually was not followed through.

Maharashtra's Model of Distribution Franchisee

In 2006, Maharashtra's distribution utility (MSEDCL) decided to experiment with franchisee approach as permitted by the Electricity Act. A franchisee is the agent of distribution licensee and derives all rights and obligations from the licensee as per the act. MSEDCL chose Bhiwandi, a power loom town close to Mumbai with a population of 1 million, for appointing franchisee. The town had estimated T&D losses of 45% and collection efficiency of 68% with 55% power being used by the power loom sector. The franchisee was to be appointed for 10 years and was required to make minimum investments for system and network improvement in the town and to perform all functions of distribution licensee using assets of the licensee and to take the employees of the licensee at its discretion. The franchise was awarded to Torrent Power on the basis of highest levelized price it quoted for the power to be supplied by MSEDCL. The price (levelized) quoted was Rs 2.04 per

kWh as against the realization of Rs. 1.44 per kWh. The quoted price is to be adjusted for any tariff increase allowed by MERC. Of course, as a franchisee, it could only charge the consumers the tariffs set by the MERC for MSEDCL. Any assets created by the franchisee were to be taken back by the MSEDCL at their depreciated value the end of the contract. This model became operational in January 2007 but ran initially into rough weather due to power shortages in the state and extensive load-shedding by MSEDCL affecting Bhiwandi as well. After initial hiccups, including resistance by the employees of state utilities, the performance of Torrent in Bhiwandi has been impressive. It has been able to reduce losses by about 30% in two years, has invested more than minimum required and has replaced meters en masse with electronic meters outside the premise and in a sealed box. Based on the experience, the state has plans to use the same model for some of its high-loss urban centres and the next area identified is some parts of the city of Nagpur.

Review of Alternative Models

Based on the successes and failures, it is evident that privatization is more likely to succeed in commercialized urban areas where quality of supply is more important to consumers than just the access to cheap or “free” electricity. It is also easier to monitor and enforce anti-theft measures in such areas and political resistance or concerns due to enforcement are also likely to be less. Such areas can have 100% metering as they do not have agricultural loads. Between Delhi model of private control of distribution licensees and franchisee model of Maharashtra, the risks and rewards are higher in the former for the private player and are lower in the latter due to “in-built” walk-out option and lack of investment in buying the equity if the performance guarantees taken from the private player are not very onerous. The Orissa and Karnataka model for distribution utilities with heterogeneous consumers spread over large areas require extensive State Government support, which can never be taken for granted by the bidders given conflict of interest post privatization. Therefore, such models are unlikely to work unless the loss levels are brought down, agriculture related issues are dealt with and sector is commercialized and is free from political interference.

More importantly the nature of the contract needs recognition. In Bhiwandi the contract with the private party was in money terms for the revenue (that the private party would give to the MSEDCL) per unit of input given the mix of consumers, their payment profiles, the tariffs and their demands. The bidder was internalising risk associated with demand, and collections. The contract being of a revenue cap type with the bidder having the mandate to keep collections in excess of revenue bid adjusted for tariff and consumer -mix changes to the MSEDCL, there were high powered incentives to go after thieves, work against connivance and marshal greater flows to paying customers. Therefore, the contract being not cost plus, but relatively clean with all improvements affecting both the top and bottom line of the bidder, it could work. The contractor not only went after the

thieves, but improved the supply to the industry in its territory, and to consumers in general, since the tariff for all consumers except the few farmers in the territory was well above the bid price per unit of electricity. The company had strong incentives to maximise the throughput through its system, being only limited by the supply that the MSEDCL could make. The very high returns the company could make was commensurate with the risks being taken up.

The Way forward

Given the experience of privatization attempts, the following may be the way forward as far as privatization is concerned-

- Sale of equity approach followed by Orissa would not work in the sector till the loss levels are brought down, agriculture related issues are dealt with and sector is commercialized and is free from political interference. Even then, any bid which increases the asset base without any investments is against consumer interest as seen in Orissa where assets were revalued upwards.
- For very large commercial urban centres, Delhi model creates better risk allocation and higher rewards as it entails minimal state interventions.
- For other commercial urban centres, franchisee model may be better due to lower risks for the private sector and the consumers continue to pay tariffs being paid by other non-privatized areas within the jurisdiction of the distribution licensee.
- Further franchising on the lines of MSEDCL's Bhiwandi experiment has much potential, especially if the DISCOM franchising out can also lay out a promise to improve and increase the supply as the revenue realisation goes up. A further development of the same to link the bid prices to weighed average of tariffs in the distribution territory being pursued by the MSEDCL is also in the right direction. But nevertheless the limitations in the model that it is based on the company internalising any 'internal' price arbitrage (misreporting consumer mix) within its distribution territory has to be realised.

5.14 Regulatory Independence and Powers

Providing Enforcement Support is Critical for Independence of Regulators

The Electricity Act 2003 puts onerous responsibilities on the ERCs for regulating the sector. Their role and functioning as per the act needs to be facilitated by the Central and State Governments by making rules, policies and by creating institutions which would enable promotion of competition, improvement

in operational and commercial viability of the sector and in protection of consumer interests. Of course, the Governments have the power to issue directions in the public interest to the players in the sector but these are meant to be exercised as an exception rather than as a rule. World over, the regulators rely typically on three instruments- (i) power to grant and revoke licence, (ii) financial rewards and penalties for desirable and undesirable behaviour respectively, and (iii) changing the extent and intensity of competition through entry and exit barriers. These have been provided for in the Electricity Act as well. Independence of regulators is ensured by the enforcement support of the state through law, through means of financial independence and through terms and conditions for appointment as a regulator including constraints on subsequent employment. These have also been provided for in the Act. Among the instruments available to a regulator, the most potent is the enforcement support offered by the state similar to what is available to courts in any modern state.

Conflict of Interest in Providing Enforcement Support to a Regulator regulating SOEs

The enforcement support given to the regulators is typically easier to get if the regulated entities are private sector entities. Even when the regulated entities are state-owned, the enforcement support is not difficult in case the state-owned entities are purely state-owned for historical reasons but are not seen as instrumentality of the state or a means for political intervention. In the context of electricity sector in India today, where most of the regulated entities are state-owned and controlled and are seen as instrumentality of the State Government's political agenda, to provide enforcement support to an independent regulator creates contradictions.

Clarity of Understanding on Role of Regulators

Typically, a regulator needs to have the enforcement power and the power to resolve disputes arising out of regulations in the regulated sector. Therefore, the regulators are quasi-judicial bodies having the power to adjudicate. But unlike a court, which usually will take up matters based on complaints and limits itself to the issues raised in the complaint, a regulator may have to look into issues arising out of a complaint in case they impact the regulated sector in terms of competition, consumers' interest and the like. It can not limit itself to the point raised in a dispute if the ruling on that has bearing on the sector in a manner not consistent with law or regulations even if such issues are not raised explicitly. The lack of this understanding is best exemplified in the civil case 2898 of 2006 in the Hon'ble Supreme Court wherein Tata Power appealed against the judgement of ATE rejecting its contention that it is entitled to supply electricity to any consumer in the territory of Reliance Energy in Mumbai. Reliance had earlier objected to the contention of Tata Power in MERC and MERC even after agreeing with Tata Power that the license conditions did imply right to supply to any consumer without

obligation to do so argued that this interpretation would result in uneven level playing field as a distribution licensee has universal service obligation as per the law and regulation. The Supreme Court accepted Tata Power's contention and rejected the ATE order and also stated that the MERC should not have gone into the issue of level playing field as Reliance had not prayed for the same and Reliance argument was based only on the license conditions for Tata Power.

Similar issues on clarity arise between regulations and policy. The latter is with the Government but there could be a very thin line between the two. If the policy making stretches itself considerably, it weakens the scope of regulations.

The Reality Today

While several states have constituted SERCs and most of them have become functional, there are still issues in terms of getting the kind of support and acceptance the SERCs should get from their respective governments. In some cases like Tamil Nadu, the tariffs determined by the TNERC in 2003 were rolled back to 2001 levels by the Government in 2006, after which no ARR has been filed by the TNEB. This happened in a context where SERC even though started in 1999 was not functional till 2002 as it had just one member! In case of Karnataka, the subsidy payments were withheld and utilities did not complain as they work under the State Government. There are state-owned utilities, which have filed for tariff petitions foregoing returns on capital thereby willing to undermine their financial viability just to keep tariffs low, presumably because the state so wished! In such cases, what would be the role of the regulator is not clear and what instruments does it have to ensure sensible behaviour? In other states too, there have been confrontations between the State Government or legislature and the SERC. The most conducive relationship in the States, which have had no such instance of open confrontation, is at best cordial but not overly supportive. Some of the state regulators also felt that the no inputs are taken from them and there is no consultative framework for evolution and review of policies. Similarly, some of the state government officials whom we met felt that even though act provides for consultation with the state governments for the policies to be framed by the Central Government, yet there is no framework for consultative evolution and review of policies.

The Way forward

Till the idea of independent regulations, which is new to the country as such, finds acceptance at the state level, it is important to strengthen these institution in terms of acquiring the kind of enforcement support, which they deserve for performing their roles effectively. A multi-pronged approach in educating various arms of the state, delimiting their exercise of power in relation with an independent

regulator, and empowering them with status and resources befitting their role is called for. Part of the problem has been with the regulators as they have tended to avoid conflict with the State Government. While tact is important in such matters, conceding too much ground for a fledgling institution could be also easily seen as a sign of weakness. Besides operational independence and enforcement powers, the regulators need to have financial resources and expertise to perform their roles effectively. These have been dealt with later in the report. For increasing their operational independence, there are various measures required. Some of these could be:

- There is need to have a framework for process of consultation between the SERCs and the Central Government to exchange views for evolution and review of policies. A parallel and similar framework may be useful for consultation with the state governments.
- Periodic review of regulatory independence by FOR or CERC or MoP. This would point out the problem areas and can be disseminated widely.
- Allowing challenge to some of the actions or non-compliance of various legal and policy measures of the State Government/ utilities in a court of law by non-interested parties.
- Insulating the SERCs from direct pressure of State Governments through creation of Independent Forums constituted at National Level rather than State Advisory Committees. The recommendation and deliberations of such a body should be in public domain and it should review the SERCs' functioning without giving any binding recommendations.
- There is need to evolve greater clarity on the understanding of role of regulators among key stakeholders. Regulators are not merely adjudicating and dispute resolution bodies even though that is an important function. Therefore, their ruling are not limited to just the complaint but also their impact on the sector. While they have to follow due process of law, that itself is not the yardstick by which they can conduct themselves. Similarly, the policy making should be careful to not interfere extensively with the scope of regulation in the sector.
- While regulators have to operate within the space provided to them under law and policies, they need to bring out the contradictions in the law and between the law and the policies in a way that allows efficiency and competition to be nurtured.
- While the issue of independence of regulation is well recognised in policy circles and in the debate, the question of the form of regulation is not raised often enough.

5.15 Regulating Private Sector Players and Utilities

State-owned Utilities vs. Private Utilities

With increasing presence of private players and a strong public sector presence, regulating the sector in India has its own challenges. In the previous section of this report, we focussed on the interface between the state and the regulator in the sector in which the state did not have to deal with an independent regulator. In this section, we focus on the issues relevant to regulating private sector players. In a fundamental sense, the state's interventions, pressures and therefore strategies of the utilities owned by the state in dealing with the regulator, are guided by public or political interests and compulsions of the state and may trade off commercial viability /commercial orientation to achieve those ends. The coercive power of state and the regulators dependence on the state may weaken the regulatory institutions, which need to be protected from such proclivities of the state. Unlike the political and public interests and compulsions, the main objective of any regulated entity owned and controlled by the private investors is commercial. Its interest would be guided by the possibility of enhancing its profits while doing the business in the sector rather than any other objective. It is therefore likely to do all that it can do, which is permitted by the law and by the regulator to maximize its profits.

Issues in Regulating Private Utilities

There are several issues in regulating private regulated entities, which are well known. Firstly, in cost-of-service or cost plus regulatory environment, there is a commercial incentive for the entity to pad up costs, both capital and revenue expenditure or not to be concerned about being cost-effective. Secondly, if the environment permits, a private entity is more likely to systematically under report revenue or over report expenditures by siphoning out cash from the entity. Thirdly, it is likely to try and find and exploit commercially any loopholes, incompleteness and inconsistency in laws and regulations more than a public entity. Fourthly, it would be willing to walk-out from its obligations if incrementally it is beneficial to do so, unlike a public entity which may have to continue due to its broader obligations to the public. Lastly, it is more likely to attempt "regulatory capture" by trying to influence favourable rulings or inconsistent rulings with a view to exploit them legally whenever commercial interests are involved.

In principle, the problem of padding up of cost can be corrected by prudence checks done by the regulator. Again in principle, the problem of siphoning out cash or value by over invoicing expenditures and under invoicing or under reporting revenues can be take care of by the auditors ensuring that all transactions are at arm's length. In reality, both these are difficult to ensure as the regulators and the

auditors find it difficult to detect such manipulation given number of transactions involved, regulatory or audit overload and lack of policing orientation and power. Their roles do not envisage extensive investigation for forming their judgement but are more on sample checks carried by them on the documents presented before them. They can seek documents but have in reality no time, power or inclination to verify the veracity of documents but to accept them at face value beyond a point. Faced with these problems, it is therefore argued that price cap regulations are better in this respect and avoid the incentives for padding up. Competitive procurement of services with simple pay-offs to the bidders also has similar advantages. The effectiveness of price cap regulation is however not as forceful for the problem of over invoicing expenditures and under invoicing revenue in case the promoters/ controlling group in the entity is interested in walking out after milking the entity. That depends on the broader environment in terms of whether such transactions can be traced ex post, how such economic crimes are dealt with and how severe is the penalty on detection.

Third problem of exploiting incompleteness of laws and regulations in also much less in price cap (RPI/CPI-x) kind of regulations or competitive bidding based procurement, as they are simple and less prone to misinterpretation and inconsistencies. They also make for low cost regulation, reduce the regulatory risks considerably and provide a way to link entry and expansion (investment decision) to the operational decisions. They provide strong incentives for cost control. Even with SOEs, these incentives would not vanish altogether. Within the cost plus framework, the onus is on the regulators and policy makers to ensure completeness and consistency in the regulations and laws respectively. Case laws can also help in ensuring that problem of interpretation is minimized.

For the walk-out by the regulated entity or the controlling group/ promoter(s) from the entity requires conditions of license, wherever required, factoring in this possibility and are designed to ensure smooth transition besides defining liability of the controlling group in such an event. Continued positive payoffs in the future also help in preventing such a possibility in most cases. In other words, if the business remains viable for the promoters they are less likely to walk-out. Planning for contingency in such a case in the form of an alternative “back-stop” promoter such as state also helps in mitigating consequences should such an event materializes.

The “regulatory capture” by direct influence requires code of conduct on the part of regulators to avoid conflict-of-interests from arising. Due diligence is also required for ensuring consistency so that loopholes are not created to the benefit of regulated entity. To sum up, the following may be useful in controlling the problems in regulating private utilities and entities-

- Regulating private sector has its own issues distinctly different from public entities as private sector is likely to exploit any commercial opportunity

offered by the laws and regulations such as padding up costs, over/under invoicing or reporting, walking-out in case advantageous, and attempting regulatory capture for commercial gains as opposed to political gains.

- Using price cap or “competitive bidding” based on simple payoffs minimizes the incentives of the private sector regulated entities to pad up costs. They should be used wherever feasible instead of cost plus regulations.
- Prudent checks and strict auditing (may be cross auditing) may help to an extent in detecting over invoicing expenditures and under invoicing revenues. Yardsticks and benchmarks for specific cost and revenue items may be used to regulate rather than actual costs to deter such behaviour.
- The terms of licensing conditions and long-term contracts should explicitly recognize the possibility of walk-out by the entity or promoter and such possibilities should be minimized by ensuring that it is not optimal for any one to walk-out by ensuring continued commercial interests. Contingencies should be planned as mitigation to avoid any serious implications should such an event happen and the liabilities on such behaviour should be enhanced as a deterrent.
- Case laws and due diligence is required as much as possible to avoid exploitation of incompleteness and inconsistencies in the laws and regulations.
- To avoid regulatory capture, code of conduct should be spelt out by the regulators and enforced to avoid conflict-of-interest situations. Rules and regulations should be cross-checked for incompleteness and inconsistencies, so as to avoid their exploitation by the regulated entities, before they are issued.

5.16 Regulatory Resources: Financial

Besides operational independence and enforcement support required by a regulator, any regulator has to be financially independent so that the regulator is not affected by its concerns for managing his office and would have the required resources to perform his role effectively. The electricity act provides for setting up of a regulatory fund, preparation of budget and accounts under the supervision of the Parliament or the Legislature. In some cases, for example Tamil Nadu, the SERC gets its funds on a quarterly basis from the State Government through the office of Chief Electrical Inspector. It is important for the functional autonomy and independence of the regulators that they be financially independent subject to oversight by the CAG and the legislature rather than be dependent on the State Government for receipt of funds. Though the problem has been as severe for any other regulator, the others also cited meagre resources, both financial and human resources, as one of the constraints for their effective functioning. It is important,

therefore, to move towards treating ERCs as autonomous institutions from financial point of view subject to oversight by the CAG and the legislature rather than being dependent on the receipts from the Government on regular basis. For this, the regulatory fees charged by them should be allowed to build a corpus of some reasonable amount.

5.17 Regulatory Resources: Human Resources and its Development

Most ERCs have Personnel of Deputation and Retirees

The Electricity regulators require a combination of skill sets in terms of human resources to perform their roles and functions effectively. They require technical, legal, economic and financial expertise and experience. Most of the regulators in India have found difficult to attract the required personnel with these skill sets of suitable quality and have been mostly manned by personnel on deputation and retirees. Most of those who have come on deputation have chosen to come due to reason of location, as ERCs are located in state capitals. On deputation, their compensations are lower due to absence of perquisites and incentives, which might be higher in their parent governmental organizations. Almost all ERCs find it difficult to get people with legal and finance expertise. While sixth pay commission covered the members of the regulatory commissions in its report, the compensation structure of other officers of the regulator also warrants a review for the regulators to attract quality staff, without which regulatory effectiveness and force cannot be expected to evolve. The more effective ERCs have tended to use external consultants, which is contingent on having enough budget and is not a perfect substitute of in-house capability.

Lack of Development of Human Resources

Not only the ERCs are understaffed or find it difficult to attract quality HR, they have been no major efforts in the direction of building capability for regulations in terms of training and exposure to regulatory economics, advances in financial markets and corporate finance, changing accounting standards, advancement in technologies in the sector and in businesses and developments in law. There is also a problem of lack of exposure and orientation for independent regulation among the regulators as most of them were previously working for the government or the utility which they are supposed to regulate in their new role.

Clearly, there is a need to have an orientation training for the regulators covering basics of regulatory economics, accounting, finance, use of IT and law and wherever required technical training. This should also include exposure to practices of independent regulations in India and abroad. Similar and more focussed training programs in each of the functional disciplines of law, finance, accounting, IT , engineering and economics may be required for the staff members. Senior staff

members also require greater exposure to practices elsewhere. In order to address these problems, the following may be a way out-

- Review of compensation and career path to attract quality officers with expertise in regulatory economics, law, finance and engineering skills. There is need to either review the provisions in the act which allows the government to set the terms and conditions of appointment or to set the scales different from the government, ERCs being autonomous bodies.
- Need to strengthen the staff at the ERCs particularly in professional categories.
- Provision of adequate budget for employing external consultants whenever required.
- Provision of budget for at least 2 weeks training per officer at a reputed institution or regulator within India or abroad.
- An orientation training program for all regulators covering basics of regulatory economics, finance & accounting, law and use of IT along with exposure to practices of independent regulators in Indian and elsewhere.
- Similarly, thrust needs to be given to training at all levels among the staff with more of perspective and competency development training at junior level and exposure at senior levels.

5.18 Harmonization of Regulations across SERCs and Building Case Law

In Indian context, where regulation in the sector is relatively new and where the principles behind regulatory orders and case laws are yet to evolve, it is important that the rulings of the ERCs and the appellate tribunal are as consistent as possible for the players and entities in the sector or interested in the sector . This will minimize regulatory risks. While the broader issues have been dealt with in the act itself, on specific issues stance of regulatory commissions and the appellate tribunal need to consistent and known widely so that each order and ruling contributes to the evolution of regulatory and legal principles invoked by the regulators. For ensuring consistency, there is a need to harmonize the regulations in terms of principles, methodologies and arguments across various regulators and the appellate tribunal. The ruling should be carefully argued in the tradition of legal orders so that they can be applied in similar situations. Currently, there is a feeling that some of the rulings across ERCs and that of AT are not consistent enough for building such case laws. To achieve this objective, the following may be useful-

- An initiative by FOR or some centralized body to act as repository of rulings by SERCs and AT, which is accessible to public as well as regulators.

- Regulators and AT to adopt a practice of citing all relevant rulings while building arguments for ruling in a particular case and laying out the reasons for agreeing or not agreeing with the previous rulings and orders.
- These would require research support to the regulators, for which adequate HR and budgetary resources may have to be provided.

6.0 Summary of Conclusions and Recommendations

6.1 Successes and Achievements so far

In this study reviewing last ten years of reforms in the Electricity sector in India, we tried to analyze the initiatives taken in last ten years, their impact and the successes and failures in attainment of the objectives set forth in reforms process. Given the complexity of the situation in the sector on the eve of reforms, the fact that the electricity sector is in the concurrent list of Indian constitution and that the state governments have to be a partner in the process, it is hardly surprising that the achievements are so far mixed. Before pointing out issues which need to be addressed and where the achievements have been not very high, we would like to point out some notable successes:

- As far capacity addition is concerned, the UMPP initiative and procurement guidelines for procurement through competitive bidding have given a major fillip to private sector participation in addition of capacities.
- Trading in power has started and induced by the price of traded power including that of exchange, has attracted private sector interest in merchant plants without PPA or with only part of the capacity contracted out through PPAs.
- ABT has been implemented and has been successful to the extent of creating financial consequences of overdrawl from the Grid.
- The availability and PLF of CPSU as well as state-sector generating plants have been improving over the years.
- The gestation period of thermal capacities has been brought down by CPSUs particularly by NTPC.
- Technology and equipment reliability of indigenous equipment supplied by BHEL has improved.
- Almost all states, with very few exceptions, have constituted SERCs and most of these SERCs have become functional.
- Several states have unbundled and reorganized their SEBs, some of them prior to and some after enactment of the Electricity Act.
- APDRP has resulted in much required investment in distribution systems in circles where APDRP has been implemented.

- There has been substantial progress in improving inter-regional and intra-regional transmission capacity and four of the five regional grids are synchronized now.
- There has been private sector interest in transmission projects as well under the new guidelines.
- Several states, which have taken reforms seriously, have brought down distribution losses and have been able to control losses at least net of subsidy (see annexure 4&5).
- In most of the reforming states, collection efficiency has improved and also losses in relatively large urban areas and on industrial feeders have come down.
- In some of the reforming states like Gujarat, schemes for feeder separation to provide 24 hours supply to rural areas independent of supply to agricultural pump sets have been implemented. RGGVY with similar objectives is being implemented by some of the reforming states.
- Keen on reforms states have also improved billing, consumer complaint system and have used outsourcing some of the functions to increase their efficiency. Partly, these initiatives have also been driven by long period of not recruiting anyone at staff and officer levels.
- While privatization in Orissa did not succeed, Delhi privatization model has been successful in terms of reducing losses, investing in the network and reducing the burden on State. After initial outcry, the acceptance among the public also has increased.
- There have been some attempts at private sector involvement in distribution in Madhya Pradesh and Maharashtra in urban centres which prima-facie, have delivered results.

6.2 Areas of Concern

Despite these achievements, there are several areas of under achievement in terms of fulfilment of objectives of the reforms. These areas of concern are:

- Capacity additions in the sector in the past have been inadequate and the energy shortages including peak level shortage continue.
- The basis of coal linkages is not clear (in the sense of optimality) even though the guidelines on priority exist. Some of the clearances required for setting up capacities are seen cumbersome and unnecessary.
- Some of the States having coal resources are not keen to promote generation capacities meant for consumption outside without getting any thing in return, for example- free power, addition revenue etc.
- The price of traded power has been high given the shortages and so has been the over drawl from Grid with frequency hovering between 48.5-49 most of the time.

- Several states have not yet unbundled the sector, a prerequisite for promotion of competition.
- Distribution (AT&C) losses continue to remain high at an unacceptable level.
- Agricultural connections are by and large unmetered and the problem of subsidy to the agriculture has not been dealt with.
- Because of unmetered connections and the quality of data, SERCs still find it difficult to determine baseline estimates of consumption across categories and extent of T&D losses.
- Financially the distribution entities remain weak at an aggregate level despite state subsidies.
- State Government still are not used to the idea of independent regulations and have continued to intervene in the sector beyond subsidization. In some states, the transfer and postings in utilities are still decided by the Secretariat.
- Some of the state government are not paying subsidies as per section 65 of the act and the distribution utilities owned by the government do not complain.
- Most of the SERCs do not feel empowered enough due to lack of support from their State Government and potential conflict with the state.
- The SERCs also find it difficult to attract quality human resources and lack the financial resources to perform their onerous roles effectively.
- Even though open access has been declared by the SERCs in quite a few states, there has been attempt to block the same by the state utilities and practically no one is availing open access even when granted.
- Though states have unbundled the sector, the STU and SLDC have remained closely linked with other state utilities organizationally and administratively for them to act independently as envisaged.
- In order to have uniform tariffs across the state, the State Governments have dynamically allocated PPAs or power allocations across distribution utilities and subsidies. This has weakened the spirit of competition even in states where multiple distribution utilities were created.
- Despite provision in the Act, no State has been able to have more than one distribution licensee in any area.

6.3 Recommendations

While recognising that the issues in the sector in a federal structure requires redressal from different arms of the state and the regulators at various levels, we list some of the specific measures which we believe will contribute to alleviation of some of the concerns listed above. The specific measures are listed under the broad categories covered in section 5 of this report.

Adding and Utilizing Generating Capacity

- As pointed out, there is reluctance among the states to allow capacities to come up unless the state itself needs power. In such cases, there is expectation of getting free power or some revenues for allowing the capacity to be set up. Currently, the states can collect duty on sale of electricity and hence do not get any revenue from sale of electricity outside the state. To overcome this problem either the state needs to be incentivised or a collective framework initiated by the Centre such as UMPP need to be created to reduce these problems for would-be investors.
- The electricity sector like any other secondary activity ought to have taxes on value added basis for central and state governments, so that on production within the states there are incentives, even when the sale is outside the state. This would as it should put state governments in competition to produce more electricity by using their natural resources effectively. This would also independently follow out of carrying through the tax reform that was initiated in 1993. In other words, the proposed GST should be extended to electricity and state governments at standard rates should be allowed to tax value added in the sector.
- There is a need to review the basis of domestic coal and associated rail linkages given to the domestic coal based plants. Greater transparency in revealing the basis of such allocation would reduce perceived risks and may also increase social welfare by making the allocations more optimal in a social cost benefit sense.
- Ideally coal sector reform is long overdue and the current artificially held low prices of coal should go. Investments need to flow into the sector and competition and low cost of mining with entry of new players are necessary to put thermal generation on a sustainable and low cost basis in India.
- The clearances required for setting up any capacity need to be reviewed, single-window clearances or prior coordination as in case of UMPPs would reduce the risks perceived and also would reduce the time taken for completing the projects. Capacity addition in some of the regions where security risks are perceived as high, have to be exploited by CPSUs, and it would not be possible to bring in private sector without bringing in perversities and rent opportunities as long as these risks remain unaddressed.
- There is a need to have transmission pricing framework whereby the costs associated with the transmission network expansion required to bring additional generation to be borne primarily by end users rather than by the customers located in regions where the transmission network has to expanded or developed.
- Given the low utilization for existing gas based capacity, it is important that new gas-based capacities are discouraged. Otherwise, existing capacities will be utilized even less and will become stranded. It is important to first

provide all the gas required for existing plants to be able to use their capacities fully before gas is allocated to new capacities.

- In this context, there is a case to review gas utilization policy as it only sets the priority of allocation of domestic gas from private producers. It may result in new gas-based generating stations using the incremental gas produced but may leave existing plants idling and capacities stranded. Since generation has been delicensed under the EA2003, no prior approval is required for setting capacity. The cost of existing already partly utilized capacity is being and will continue to be borne by the consumers in addition to the cost of new capacity. That would be socially wasteful and against consumer interest!
- The past experience of takeover of poorly performing plants such as Tanda, Unchahar etc. by NTPC resulted in dramatic improvement in the performance of these plants. In addition to new capacities, there is a need to facilitate such takeover if the state sector plants continue to perform poorly despite potential. From consumers' point of view, it would be much better if the poorly performing plants were to improve rather than adding capacity for an equivalent generation and hence, incentives need to be created to either improve the performance in a time-bound manner or takeover/privatization. The former option may be better as it would be less controversial as well.
- All these may become more important going forward as the "hot IPO markets" of 2006 and 2007 no more exist and the equity markets for providing fresh risk capital may not revive till global recession is over. In the absence of high risk appetite of the markets, promoters may be extra careful with their own money than they were in the recent past.

Competitive Procurement of Power, ABT and High Price of Traded Power

- Currently, there is no explicit provision in the Act or the policies, requiring that the distribution licensees adequately contract for their power requirements or capacity except for their obligation to supply reliable and quality power based on performance standards laid out by the ERC (section 86(1i)). In fact, the procurement guidelines require taking approval for procuring more than projected requirements but not for ensuring adequate procurement.
- Unless the ERC can insist and enforce either the performance standards in terms of limits on load-shedding or adequate contracting by the distribution licensee, any loss-making, high AT&C loss laden distribution licensee is unlikely to contract for more than bare minimum requirement to avoid payment of capacity charges but would prefer UI route or short-term traded power to be used whenever absolutely required (for political or other similar reasons) and to shed load otherwise. The above is not true for a profit maximising utility as it would proactively contract and serve all its customers in the pursuit of profits. Save few, most distribution utilities

currently do not make profits by supplying more power or by fully meeting demand 24 hours. While under section 23 of the Electricity Act, the SERCs can issue direction on equitable distribution and under section 86 (1i) can specify quality levels, non-compliance can at best only ex post evoke penal.

- In the current framework, there is no incentive for anyone to contract for or to invest in peak power as the capacity charges would have to be paid for or recovered for the day despite using the capacity for a short period of time. The peaking power or such short-term power would have to be supplied at high prices to recover full costs over a short period of time. But for the load shedding, the peaking power would have been even more costly.
- To incentivise adequate contracting and to disincentivise load shedding and overdrawing, provisions available to ERCs in the Act may not be very effective as they are based on instances of violation of performance standards if they are part of license conditions or regulations. Instead, tariff fixation itself should penalize and reward such behaviour. That means lower tariffs should be allowed if UI or load shedding is resorted to and higher tariffs in case reasonable power has been contracted.
- Not allowing high cost of short-term procured power or UI charges is unlikely to be effective as the utility would still be better off not contracting as the absolute amount would be low if used for very short period and load shedding resorted to otherwise.
- High cost/price of electricity for base load periods and high price for peak periods reflects different problems in the electricity sector. While the former is a consequence of lack of adequate supply relative to the base load demand, the latter is a consequence of capacity cost recovery by merchant plants that are not paid for during idle period. Poor capacity addition and wanting energy efficiency are the reasons for the former and very sharp peak loads are reasons for the latter. The regulators, therefore, must insist on demand side management measures to flatten the load curve through time of the day tariffs and energy efficiency measures in the short run.

Trading in Power and Its Regulation

- Given the nature of trading and difficulties involved in regulation of trading, either trading margin regulation provisions should not be used or the definitions of inter state and intra state trading needs to be defined tightly along with stipulation on how many layers through which traded power can reach end consumer(s).

Developing Market in Electricity Sector

- ABT based management of imbalances does not ensure the long and medium term response of the system to overcome consistent imbalance in

- one direction (shortages). This is because investment decisions cannot be made on the imbalance revealed by the ABT unless these imbalances become very large and reflect themselves in the form of persistent low frequency, over draws, and high cost of traded and peak power. ABT cannot provide a vehicle to link competition for the market (involving investment and entry decision) to competition in the market (i.e., with regard to operational decisions) unlike market determined prices.
- At present, while bulk of the scheduling /dispatch decisions are based on variable costs, the traded power (on energy-only basis) actually gets to be scheduled on total cost basis. The new breed of merchant power plants, coming up under the new policy framework (Case I and II), are also likely to be scheduled on total cost basis (or contracted energy charges under long-term PPAs rather than on real-time bid basis). In any case, there is no bidding to reveal “true” costs on real time basis.
 - An alternative to ABT would be to tie-up existing capacity and energy contracts between generators and DISCOMs as they exist and create a market on gross pool basis with separate capacity and energy markets, and prices emerging for both. Another alternative would be to organize the imbalance market on net pool or energy-only basis but to accept high price volatility in imbalance market.
 - In a gross pool, the DISCOMs should tie-up the capacity before they requisition for energy. In case they do not, they have to pay for capacity as well as energy simultaneously but separately. In the net pool, it would not be mandatory for all of the capacity or the energy to come on to the market but only an “imbalance” market based on bids and offers is required. The bids and offers would be on energy-only basis without separate capacity charges for electricity procured through market. Both options would necessitate moving away from frequency and pre-fixed prices in the spot market to price discovery. Both options would require greater control on system operators (or load dispatch centres) and players in the sector by the regulators. Over draws and under injections would have to be settled on real time basis through market prices rather than frequency linked prices.
 - The exercise of market power in a bid and offer based real time spot market, as opposed to ABT based imbalance market, is less likely if there are enough capacities and players and also if most of the capacity is on long-term financial contracts. In the latter case in the context of a gross pool, where every generator has to bid, the incentive to game is considerably reduced as the gains from gaming and setting high spot prices are low once the existing contracts are considered as financial contracts whereby the generator may decide to buy from the or generate depending upon the price already contracted. Any gains from high prices are notional as the generator with existing contract has to pass on these gains to buyers.
 - The concern of exercise of market power in the Indian context is real given the demand-supply situation in India. It is also recognized that it is not easy to create spot markets without eliminating gaming opportunities. However,

if all existing long-term contracts are retained as financial contracts then the incentive to game would be very low for the existing generators if they were to bid in the spot market. This would also not impose any tariff shock to the retail consumers. Only some pre-defined consumers, who are on TOD meters, may be expected to bear the risks associated with spot market prices. Another way to lessen this problem would be to specify a price cap, as in the case of Australian market. How high this price cap should be given price inelasticity of demand is a call to be taken by the policymakers and regulators? If it is set too low, the purpose of market price (to signal scarcity value) is defeated and keeping it very high increases the incentive to game the market.

- For the markets to respond to real time prices, the wholesale prices need to be passed on to the end consumers at least to large consumers through TOD metering and TOD tariffs.
- The real time markets would also require real time system operator support in determining congestion and security constraints (so that infeasible contracts are not entered into) and the transmission prices need to be such that they reflect marginal losses and congestion charges if there is any congestion in the system.

Open Access and Reduction in Cross-subsidies

- The cross-subsidy surcharge needs to be lowered so that the end consumers may find it economical to avail of the open access. While this has been done by several states, other states' SERCs need to review and lower the same.
- The standby charges also need to be reviewed and should be reasonable if the objective is to promote competition through open access availed by the end consumers.

Besides surcharge and other charges, there is a need to ensure that the SLDC/STU are not seen to be acting in the interest of the distribution licensee. It is also important that the incumbent does not use the excuse of reliability and quality of supply to deny open access.

Transmission Pricing Issues

- There is a case for incorporating costs associated with transmission network expansion or strengthening to be factored in while evaluating the cost of adding new generation capacity at alternative locations. These costs should be borne by the beneficiaries of those who are going to consume the power from that capacity. The framework should be such that it does not inhibit investment in generation capacities or transmission network expansion by

making them hostage to *ex ante* unwillingness of the users to pay for transmission costs.

- Some proportion of the capacity costs (capital and O&M costs) related to other existing transmission assets should be allocated based on some distance related measures. These distance measures can be determined from typical or average flow patterns on the network given loads and generators. Load flow studies can help in approximating the average lead. Some proportion of these costs should be recovered from all consumers as the network also enhances reliability for all consumers and its function is not limited to evacuation of power.
- Losses and congestion costs should be recovered at different levels from different nodes or zones depending upon the marginal loss induced by increase of load at that node or in that zone. These can be computed dynamically using load flow software or if the load flow pattern does not change significantly over a period of time, the basis could be typical load flow pattern. These charges can be reviewed as and when the load flows are expected to change due to addition of generation capacity, network changes or changes in demand pattern across nodes/zones.

Competition among Distribution Companies

- The political will of the State Government is required to let distribution companies compete in terms of performance with its role being only through the board and as a the shareholder. This may entail fixing capacity allocations, subsidies and other support in advance for multiple years. This would allow the accounts of DISCOMS to meaningfully reflect commercial performance. The upfront allocations can be done to minimize tariff variations within the State but not to necessarily make tariffs identical. With the abolition of freight equalization schemes in other products as coal and oil, the public has the experience to accept small variations in prices at different locations.

Competition through Captive generation

- Review of all captive capacities, which have agreements with the SEBs or utilities by the ERCs to make sure that the terms are at least as favourable as alternative sources of power available to the SEBs and their successor DISCOMs, including through the ABT.
- Encouragement by the SERCs and the State Governments to use captive power for peaking load and meeting energy shortages in line with “Pune Model”. Despite limitations of the Pune model, utilization of idle captive capacities is desirable as the alternative entails addition of new capacity, which may be wasteful for peaking power if required for very short periods.

Competition through Multiple Distribution Licensees

- Allowing access to wires and distribution system to competing distribution supply utilities for the use of their assets at a charge which compensates them for their investment and provides adequate return. This, however, mean computing wheeling charges for each area where competing licensees are allowed. It would also mean variation in end consumer tariffs within a state unless subsidized by the State Government. For that, there has to be political willingness and acceptance of competition on the part of the State Government.
- The State Government has to be seen as supportive of competition with its own utility and should be able to accept variation in tariffs across State. The independence of STU/SLDC has to be signalled credibly by having only arm's length relationship between it and the State Government and/or with DISCOMs/GENCOS.

Reduction in Distribution Losses

- To start with, there is a need to have consistency across time-periods and utilities in the way the distribution loss and efficiency measures are computed and reported, which is currently not the case. Transmission losses need to be separated from distribution losses. Currently, the magnitude of total distribution losses is not clear with AT&C loss being end product of technical losses, commercial losses and collection efficiency. While reporting input and realized energy, traded energy should be excluded as it can bias the measure and technical, non-technical losses and collection efficiency need to be separately measured consistently. A problem that stands in way of such separation even at the aggregate level is the presence of billing on assessed basis.
- Regulators have yet not been able to either form baseline estimates of all the three relevant measures of efficiency in most cases, nor do they have confidence in the use of current measures. Greater thrust on the same is required by segregating technical losses through first estimating technical losses feeder wise through simulation or through feeders having no commercial losses and then subtracting it from aggregate losses to arrive at a product of commercial loss, technical loss and collection efficiency separately.
- The feeder level meter readings should be automated. Gujarat and Rajasthan have reportedly completed AMR (automated meter reading) for feeder level metering. There is a need to reduce and monitor defective as well as reported NA/NR readings. The energy accounting system should be integrated with billing system.

- The economics of use of AMR needs to be worked out for large consumers. It might be more effective above a certain connected load to have AMR for such consumers. Once determined, a time bound program should be mandated for all utilities to resort to AMR for such consumers.
- Linking quality of supply (including load-shedding) with the losses and collections on a feeder. Even though the policies spell it out, ERCs and the State Government have not attempted this linkage. Obviously, such a measure requires political will but with the support of ERCs, this linkage can be and should be implemented. In fact, an order by MERC (Maharashtra) requiring higher load shedding for consumers of high loss areas was legally upheld. Such measures may create strong social pressures on defaulting consumers or those who indulge in theft/unauthorized use. MERC has also allowed reliability charge in order to recover cost of procuring costly power for quality supply in Pune, which is also an effective way of differentiating tariffs using quality of supply.
- Supporting stringent measures on theft and creation of Special Courts as provided in the Act. Even though the Act provides for stringent measure including criminal and civil liability in cases of theft, the State Governments have not been too keen on the implantation of these provisions across the board. Some have informally told the distribution utilities to not initiate action under the criminal provision of the law for the first time defaulters.
- Stronger linkage of rewards and punishment of distribution company's employees, engineers and managers with the losses for the areas under their control. The linkages currently are weak and given the extensiveness of the problems, the utilities have limited degrees of freedom. In a state like Assam, the average age of employees is 54, due to lack of recruitment for several years and to expect too much effectiveness from such measures is unrealistic. Nonetheless, it is difficult to envisage the improvements without such accountability. Similarly, there is a case for implementing MYT framework to incentivise loss reduction for the distribution utilities.
- Another way out is to create competition through multiple licencees, open access and captive generators so that there is enough pressure on the distribution utility to reduce losses and improve efficiency. The experience of Maharashtra in select areas where private entities were handed over distribution on behalf of the distribution entity as a franchisee also points at the possibility of using private entities in reducing the losses provided the state is willing to provide enforcement support.
- It goes without saying that for all this to happen the State Government not only needs to have political will but would have to create governance structures to minimize / eliminate political interference in the sector despite temptations to interfere in the process of action against theft and defaulters. In fact, the least that the state government and the local governments can do is pay the bills their own bills on time. The payment from the government, municipalities and their departments remains outstanding for considerable periods of time!

- Some of the state governments have policies, which are still reflective of the mind set of treating utilities as non-commercial entities despite corporatization and unbundling. These include policies on procurement where the utility is expected to give preference to or have certain percentage of orders going to entities located in the state (for example, Gujarat). The evaluation of bidders is also done on pre-tax basis. The costs associated with such policies in the form of higher prices/taxes paid by the utility are ultimately borne by the consumers and such policies need to be reversed. The regulators also need to protect the consumer interest in such cases even though such initiative can be undermined by issuing policy direction under section 108.
- Another example of such type is non-filing for tariffs by state government utilities (Tamil Nadu) or by filing tariff with ARR based on no/low returns (Haryana) on equity. Such policies or interventions are against the viability of the sector and better way of subsidizing would be by paying subsidies to the utilities or consumers rather than subverting principles of commercial operation of the sector.

Movement to Direct Subsidies

- The only sustainable way to overcome the distortions and reduce the cost of subsidisation to only a small fraction above the delivered subsidy is to subsidise the farmer through entitlements or endowments that allow him to access the subsidy and which are tradable.
- There is a need to move towards endowments based subsidisation, and away from price based subsidies.
- The current measures of excessive feeder separation, excessive meterisation impose avoidable social costs, since they would not have to be incurred in a regime of direct subsidies. Policy and regulation which have favoured such technological and investment heavy approaches to the problem are opening the doors to a high cost system and the increasing the “directly unproductive activity” in society. The solution lies in exit from the use of lower prices to subsidise, to direct entitlements.

Prompt payment of Subsidy by the State Government

- Empower further the ERCs to insist on demanding proof of payment from the utilities and change the tariffs accordingly if the payment has not been made. This, however, may be difficult in current scenario as SERCs do not feel empowered enough and besides imposing penalty on the utility, have limited means of enforcement to ensure that utilities charge tariffs as

specified. This can also set them on a course of collision with the State Government.

- Alternatively, there can be another structure which can be put in place by the Central Government through policy backed by monitoring, which incentivises limiting subsidies and prompt payment of the subsidies.
- Of course, the first best solution to the subsidy problem not envisaged as of now in the Act or policy framework is “direct subsidy” to the intended beneficiaries.

Independent STUs and SLDCs

- The State Governments have to let go at least the STU and SLDC as part of their administrative framework of Ministry of Power and Energy. Organizational and reporting structure for these entities, ideally, should be different and they should have no KPIs other than reliable and secure system operations within the framework put in place by the SERC.
- Ringfencing STU and SLDC may require administrative, financial and organizational changes so that they can operate independent of the other entities purely on technical and operational considerations without any commercial and geographic interests in mind.
- Manning of SLDC is critical in terms of training and protecting them from ire of any other entity and they should be completely accountable internally or to the SERC. Extensive training for independent system operation, setting up means of coordination and control and equipment for achieving the same should be taken up urgently as it is critical for effective and efficient functioning of SLDCs.
- The data on transmission system capacity, load flow studies and decision-rules for determination of “non-discriminatory” open access should be displayed on the web-sites of SLDCs on real time basis, wherever required.

Privatization Models

- Sale of equity approach followed by Orissa would not work in the sector till the loss levels are brought down, agriculture related issues are dealt with and sector is commercialized and is free from political interference. Even then, any bid which increases the asset base without any investments is against consumer interest as seen in Orissa where assets were revalued upwards.
- For very large commercial urban centres, the Delhi model creates better risk allocation and higher rewards as it entails minimal state interventions.
- For other commercial urban centres, franchisee model may be better due to lower risks for the private sector and the consumers continue to pay tariffs being paid by other non-privatized areas within the jurisdiction of the distribution licensee.

Regulatory Independence and Powers

- There is need to have a framework for process of consultation between the SERCs and the Central Government to exchange views for evolution and review of policies. A parallel and similar framework may be useful for consultation with the state governments.
- Periodic review of regulatory independence by FOR or CERC or MoP. This would point out the problem areas and can be disseminated widely.
- Allowing challenge to some of the actions or non-compliance of various legal and policy measures of the State Government/ utilities in a court of law by non-interested parties.
- Insulating the SERCs from direct pressure of State Governments through creation of Independent Forums constituted at National Level rather than State Advisory Committees. The recommendation and deliberations of such a body should be in public domain and it should review the SERCs' functioning without giving any binding recommendations.
- There is need to evolve greater clarity on the understanding of role of regulators among key stakeholders. Regulators are not merely adjudicating and dispute resolution bodies even though that is an important function. Therefore, their rulings are not limited to just the complaint but also have to be concerned with their impact on the sector. While they have to follow due process of law, that itself is not the yardstick by which they can conduct themselves. Similarly, the policy making should be careful to not interfere extensively with the scope of regulation in the sector.

Regulating Private Sector Players and Utilities

- Regulating private sector has its own issues distinctly different from public entities as private sector is likely to exploit any commercial opportunity offered by the laws and regulations such as padding up costs, over/under invoicing or reporting, walking-out in case advantageous, and attempting regulatory capture for commercial gains as opposed to political gains.
- Using price cap or "competitive bidding" based on simple payoffs minimizes the incentives of the private sector regulated entities to pad up costs. They should be used wherever feasible instead of cost plus regulations.
- Prudent checks and strict auditing (may be cross auditing) may help to an extent in detecting over invoicing expenditures and under invoicing revenues. Yardsticks and benchmarks for specific cost and revenue items may be used to regulate rather than actual costs to deter such behaviour.
- The terms of licensing conditions and long-term contracts should explicitly recognize the possibility of walk-out by the entity or promoter and such possibilities should be minimized by ensuring that it is not optimal for any

one to walk-out by ensuring continued commercial interests. Contingencies should be planned as mitigation to avoid any serious implications should such an event happen and the liabilities on such behaviour should be enhanced as a deterrent.

- Case laws and due diligence is required as much as possible to avoid exploitation of incompleteness and inconsistencies in the laws and regulations.
- To avoid regulatory capture, code of conduct should be spelt out by the regulators and enforced to avoid conflict-of-interest situations. Rules and regulations should be cross-checked for incompleteness and inconsistencies, so as to avoid their exploitation by the regulated entities, before they are issued.

Regulatory Resources: Financial

- Treating ERCs as autonomous institutions from financial point of view subject to oversight by the CAG and the legislature rather than being dependent on the receipts from the Government on regular basis. For this, the regulatory fees charged by them should be allowed to build a corpus of some reasonable amount.

Regulatory Resources: Human Resources and its Development

- Review of compensation and career path to attract quality officers with expertise in regulatory economics, law, finance and engineering skills. There is need to either review the provisions in the act which allows the government to set the terms and conditions of appointment or to set the scales different from the government, ERCs being autonomous bodies.
- Need to strengthen the staff at the ERCs particularly in professional categories.
- Provision of adequate budget for employing external consultants whenever required.
- Provision of budget for at least 2 weeks training per officer at a reputed institution or regulator within India or abroad.
- An orientation training program for all regulators covering basics of regulatory economics, finance & accounting, law and use of IT along with exposure to practices of independent regulators in Indian and elsewhere.
- Similarly, thrust needs to be given to training at all levels among the staff with more of perspective and competency development training at junior level and exposure at senior levels.

Harmonization of Regulations across SERCs and Building Case Law

- An initiative by FOR or some centralized body to act as repository of rulings by SERCs and AT, which is accessible to public as well as regulators.

- Regulators and AT to adopt a practice of citing all relevant rulings while building arguments for ruling in a particular case and laying out the reasons for agreeing or not agreeing with the previous rulings and orders.
- These would require research support to the regulators, for which adequate HR and budgetary resources may have to be provided.

Exhibit 1:

The List of Officials met during the Study

1. Dr. Pramod Deo, Chairman, CERC
2. Sh. Bhanu Bhushan, Member, CERC
3. Sh R. Krishnamoorthy, Member, CERC
4. Sh. Alok Kumar, IAS, Secretary, CERC
5. Sh. Sushanta K. Chatterjee, Dy. Chief (RA), CERC
6. Sh. K.P. Pandey, Chairman, KERC
7. Sh. H. Sashidhara, Secretary, KERC
8. Sh. S.M. Jaamdar, IAS, MD, Karnataka Power Corporation Ltd.
9. Sh. A.N. Ramesha, Director (Technical), Bangalore Electric Supply Co. Ltd.
10. Sh. G.V. Balaram, GM, Bangalore Electric Supply Co. Ltd.
11. Sh. E. C. Arunachalam, TNERC.
12. Sh. R. Balasubramanian, Secretary, TNERC.
13. Sh. A.K. Sachan, IAS, Member (Finance), Assam SEB, MD, Lower Assam Dist. Co. Ltd. & Central Assam Dist. Co. Ltd.
14. Sh. Sunil Mitra, Additional Chief Secretary, Department of Power and Non-Conventional Energy Sources, West Bengal Government.
15. Sh. K.L. Biswas, Secretary, WBERC
16. Sh. P. Ray, WBERC
17. Sh. M.K. De, Chairman & MD, WBSEDCL.
18. Sh. P.K. Chakrabarty, ED(Corporate), WBPDCCL
19. Sh. Utpal Bhattacharya, ED (Corporate Service), CESC Ltd.
20. Gargi Chatterjea, GM (Regulatory Affairs), CESC Ltd.
21. Sh. Berjinder Singh, Chairman, DERC
22. Sh. K. Venugopal, Member, CERC
23. Sh. Amarendra K. Tewary, IRS, Secretary, DERC
24. Sh. H.G. Garg, Director (Law), DERC
25. Sh. B.K. Sahoo, Director (Engineering), DERC
26. Sh. Harish K. Ahuja, Deputy Secretary (Power), Delhi Government
27. Dr. Pawan Singh, Director (Finance), Delhi Transco Ltd. & Delhi Power Co. Ltd.
28. Sh. Arup Ghosh, COO, NDPL.
29. Sh. Arun Kanchan, Chief Executive, BSES Yamuna Power Limited.
30. Sh. Rajeev Chowdhury, DGM (Regulatory Affairs), BSES Rajdhani Power Ltd.
31. Sh. Anand Kumar, Member, UERC
32. Sh. V.K. Khanna, Member, UERC
33. Sh. Prabhat Kumar Sarangi, Secretary, Uttarakhand Government.
34. Sh. R.P. Thapliyal, MD, UJVNL

35. Sh. T. Panda, Director (Finance), Uttarakhand Power Corporation Ltd.
36. Sh. J.M. Lal, Director (Operation), Uttarakhand Power Corporation Ltd.
37. Sh. V.P. Raja, IAS (Retd.), Chairman, MERC.
38. Sh. A. Velayutham, Member, MERC.
39. Sh. Prafulla S. Varhade, Director (Elec. Engg.), MERC.
40. Sh. M. Palaniappan, Consultant, MERC.
41. Sh. N.C. Amzare, Maharashtra State Electricity Distribution Co. Ltd.

Exhibit 2: Plant-Load Factor in India in Early 1990s (%)			
Year	SEB Stations	NTPC Stations	All-India Average
1980	n.a.	—	44.7
1990-91	51.3	61.67	53.89
1991-92	49.6	70.39	55.4
1992-93	54.1	70	57.1
1993-94	56.5	78.09	61
1994-95	55	76.6	60

Source: NTPC and Annual Reports of the Ministry of Power

Exhibit 3: Financial Performance of SEBs in early 1990s (Rs. crore)			
	Losses Before Subsidy	Subsidy from Government	Uncovered Losses
1991	3080	1497	1580
1992	4020	1202	2820
1993	4560	3182	1380
1994	5060	2354	2710
1995	6130	5127	1000

Source: Virendra K Sharma, *Electricity India Vision 2027*, Galgotia Publications, New Delhi, 2004

Exhibit 4: Transformation, Transmission and Distribution Losses since 2000-01 (%)					
State/UT	2000-01	2001-02	2002-03	2003-04	2004-05
Haryana	39.82	39.22	37.65	32.07	32.11
Himachal	23.38	25.55	21.16	22.76	28.90
J&K	45.39	48.85	45.55	45.54	41.08
Punjab	26.58	27.70	24.42	25.96	25.42
Rajasthan	29.76	43.06	42.61	43.74	44.68
UP	36.94	37.62	34.16	35.17	34.39
Uttarakhand		32.39	25.17	49.23	39.3
Chandigarh	25.41	24.97	24.06	39.06	30.37
Delhi	44.27	43.97	45.82	43.66	45.40
BBMB	4.32	4.81	5.20	1.22	0.98
Gujarat	28.14	26.87	28.52	24.20	30.43
MP	46.07	44.55	43.31	41.44	41.30
Chattisgarh		33.75	37.86	42.55	28.06
Maharashtra	33.81	37.28	34.01	34.12	32.40
D&N Haveli	39.84	27.22	40.26	15.10	16.00
Goa	28.70	25.18	40.26	45.05	35.97
Daman & Diu	11.38	7.52	14.95	16.88	15.56
AP	36.63	26.81	30.11	27.73	23.96
Karnataka	34.93	33.83	24.57	23.29	26.08
Kerala	18.44	32.21	27.45	21.63	22.48
Tamil Nadu	15.72	16.06	17.31	17.16	19.28
Lakshadweep	6.71	10.94	11.29	11.85	10.20
Pondicherry	7.93	12.0	21.10	11.60	18.15
Bihar	17.86	51.70	37.98	36.66	38.88
Jharkhand		26.39	21.19	25.35	19.62
Orissa	44.91	47.34	45.36	57.09	44.02
Sikkim	24.98	31.73	54.85	54.99	50.49
West Bengal	29.44	31.67	25.93	31.01	28.54
Andaman & Nicobar	17.49	29.20	19.78	25.95	12.63
DVC	4.75	3.63	3.34	2.69	2.69
Assam	40.71	42.78	38.30	39.31	51.76
Manipur	58.49	62.35	63.66	65.18	70.61
Meghalaya	20.97	22.66	21.92	16.73	28.35
Nagaland	24.60	52.32	56.71	55.00	48.26
Tripura	43.89	40.38	40.64	46.44	59.54
Arunachal Pradesh	34.41	53.58	38.95	47.54	42.96
Mizoram	45.42	49.77	46.91	55.54	66.14
All India	32.86	33.98	32.54	32.53	31.25

Notes: (a) This exhibit is from the IIPA report on "Impact of restructuring of SEBs" originally attributed to the CEA. (b) As is evident from the table, the data quality is suspect. For example, Bihar had reported losses 17.86% in 2000-01 whereas it became 51.7% in 2001-02 and later around 38%. Similarly in case of Nagaland, it moved from 24.6% in 2000-01 to 52.32 in 2001-02 and stayed at those levels. The problem is with energy accounted for on assessed basis, which continues to be the case for some states. The assessment can also vary year to year making any analysis meaningless

Exhibit 5: Commercial Profit/Loss of State Power Utilities with Subsidy since 2000-01 (Rs. crore)					
State/UT	2000-01	2001-02	2002-03	2003-04	2004-05
AP	-932	284	855	1467	1231
Assam	-379	-549	-587	-631	-907
Bihar	-670	-1167	-1456	-1511	-1606
Delhi	-1055	--	-881	-1609	-584
Gujarat	-2604	188	101	-343	649
Haryana	-1548	-919	-5	187	-392
Himachal	-92	-120	-98	83	-58
J&K	-990	50	-1112	-996	-1032
Karnataka	76	213	103	412	621
Kerala	-348	-682	138	-211	-117
MP	-2800	-2197	11	1015	-296
Maharashtra	-1404	-451	-368	415	2209
Meghalaya	-34	-24	-55	65	-23
Orissa	-212	36	-475	422	464
Punjab	-1477	-1415	-40	1528	1315
Rajasthan	615	-1581	-626	-412	-578
Tamil Nadu	-1197	-4457	700	-494	-139
West Bengal	-1009	-1181	-94	183	713
UP	-1734	-1395	-295	-1004	-3557
All India	-17794	-16725	-4846	-2268	-3438

Notes: (1) This exhibit is from the IIPA report on "Impact of restructuring of SEBs" originally attributed to the Planning Commission and PFC. (2) As is evident from the table, the losses net of subsidy declined over the period. Part of the reason has been the greater willingness and compulsion for payment of subsidies by the state governments during the period. (3) Without subsidies, the corresponding numbers were -25259 crore in 2000-01 and -22129 crore in 2004-05. (4) Periods later than 2004-05 have seen improvements in select states which have continued focus on reforms in the sector. The finalization of accounts still remains a problem in quite a few states and the corresponding statistics on all-India basis are available with considerable lag.