Stanford-CMU Indian Power Sector Reform Studies

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"The most challenging unbundling of all would be that of the bureaucracy"

– Editors' comment, India Infrastructure Report 2002.

0. Summary

India's power sector is undergoing significant reforms, beginning in 1991, which are changing and diminishing the role of the government, which functioned earlier as the near monopoly integrated utility. From being government departments, the State Utility Boards (SEBs) are being unbundled, and the role of the government might be recast as the regulator and (last resort) financier, with operations in the hands of companies, especially private companies or privately controlled companies.

The SEBs have been the entities responsible for delivery of power to consumers, and though there was modest generation capacity within Central generation companies (public sector companies) like NTPC, the overwhelming majority of transmission and distribution lay in the hands of the SEBs. SEBs were government (mis)managed, and their tariffs were not only well below their true costs, they were skewed with heavy subsidies for agricultural consumers (who consume almost a third of the power today). In fact, agricultural consumption is unmetered today, and thus, unknown with any high level of confidence. The agricultural sector, subsidized in most aspects in attempts to control food prices (and cultivate a powerful vote bank), is possibly the greatest challenge facing the power sector in India.

SEBs never functioned like efficient companies, despite the 1948 Act that created them mandating their garnering 3% Rate of Return on their asset base. Instead, the utilities are making massive losses, in the billions of dollars per year, partially because of tariff skews and irrationality and partially because of poor tariff collection and high

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losses (technical transmission and distribution losses are some 15 or more percent, while "commercial" distribution losses – theft – are about 15%; no one knows the true numbers). The performance of the utilities has been very poor, with blackouts and brownouts a regular feature in Indian life. Because of this, and also facing higher tariffs – set high to cross-subsidize agricultural and domestic consumers, industrial and commercial users have extensively switched to captive power, or self-generation. This further worsens the utilities situation, losing their main paying customers. In the end, the absolute subsidies required by the sector, unavailable in state budgets, has grown to billions of dollars, measured in the percent-plus range of GDP.

Because of significant financial difficulties faced by the SEBs (and in the state budgets, which financed the SEBs), 1991 saw the enactment of legislation, the 1991 Electricity (Supply) Act, which opened up the sector to private participation, primarily in generation. IPPs were heavily encouraged through preferential policies (like guaranteed 16% returns, post tax, in US$ if applicable), but very little capacity addition came about. Power sector reforms were a mirror of overall economic liberalization and reforms in India in 1991, which were triggered by a severe balance of payments crisis, which led to India abandoning years of controlled growth. Foreign direct investment was especially targeted in the power sector, given the limits on domestic savings. These were facilitated by the 1990s' increase in capital movements (globalization), worldwide rise of IPPs, and the increased use of combined cycle power plants operating on natural gas (or liquid fuel). To grow India's capacity by 100,000 MW, a ten-year target, India looked to draw investments of some 150 billion dollars.

However, much of the initial policies focused on generation at the expense of other segments of the power sector. Even within generation, public sector entities were given lowered budgets (and incentives – 12% versus 16% for IPPs). The increase in private generation was very limited, and its costs were often too high for the SEB to bear. The Enron (Dabhol) episode only heightened people's concerns with and opposition to power sector reforms, especially foreign participation. The power purchase agreement (PPA) was secret and arrived at without competition (through a Memorandum of Understanding), allowed for very high (30%) returns (on paper), and the utility had committed to 90% offtake from a massive generation station, levels it could not justify in terms of least cost dispatch. The opposition was so intense that the state government briefly took the utility to court to stop the PPA. Clearly, other reforms beyond just "generation at any cost" were required, as the power situation in India went from bad to worse through the mid 1990s. Because the fundamentals had deteriorated so badly, foreign interest in India's power sector (not just generation), high during the early 1990s, had all but come to a halt by the mid to late 1990s.

The subsequent reforms begin in the mid-1990s (in Orissa, extending later to other states, and the center in 1998) focusing on structural changes in the power sector, with the establishment of independent Electricity Regulatory Commissions as quasi-judicial bodies. These reforms were often driven by the World Bank, who made them a pre-condition to assistance, and there was a worldwide trend towards such reforms (perhaps part of the TINA mentality – There Is No Alternative). The state utilities were or are in the process of being unbundled, largely through corporatization as public sector companies. Privatization has been limited, with just Orissa (the initial reformer) and Delhi, in 2002, privatizing distribution, with *competition* only for the privatization process, not for retail tariffs.

While generation has been competitive on paper, with SEBs even previously taking power from central generation stations, the structure was never levelized (with internal generation facing only marginal costs from a dispatch perspective). Even with reforms, while theoretically competitive, bulk supply is still expensive, with a flat rate tariff based on generation (or availability, now, instead of load factor). Most of the power purchases by states from outsiders have been based on bilateral PPAs, which are reasonably rigid in terms of guaranteed offtake, tariff, escalation of cost components, and long lifetimes. Without a good system for instantaneous supply-demand matching (through detailed forecasts and load duration curves, if not real-time markets), power was always considered to be something measured just in raw kilowatt-hours, with no distinction made for time of day, source, marginal costs, etc. This structural deficiency continues somewhat even with reforms, as all the numbers discussed are average numbers, with little appreciation for *marginal* cost pricing, long-term or short-term.

Today, the average cost of supply is approximately 3.5 rupees/kWh (a little over 7 cents), while the average revenues are only 2.5 rupees/kWh. Even with an increase in tariffs with reforms (and less government interference in setting rates), the average cost of supply is also expected to go up for several reasons (hopefully offset somewhat by lower losses). Firstly, the average cost of supply today is a historical number (and not correctly calculated in government publications), and newer capacity, regardless of ownership or even fuel, will cost measurably more, around Rs 2-2.4/kWh. Reforms will not change the cost of generation unless it truly becomes more competitive, and further reductions are unlikely to occur as long as power purchase agreements are the norm, which lock in prices. Secondly, as the utilities are privatized (or even corporatized and forced to act like businesses, making a profit, or at least lacking government subsidies), the costs per subsection of the industry (transmission, distribution, and even generation) will increase. The increase in tariffs because of reforms and the quest for profitability might be 30 paise/kWh, if not more.

Another structural deficiency with the system, even under reforms, focuses on efficient grid operation, discipline, and dispatch. While the states have financial implications for such activities, the control is ostensibly at the regional level (as India does not have an integrated national power grid). Generators today often don't back down, as this reduces their returns, which have been based on load factors. After reforms, the Central Electricity Regulatory Commission (CERC) instituted a modified bulk tariff mechanism to address such issues, which is based on availability instead of actual generation. This goes some ways towards improving the system, but has flaws based on time constants, and perhaps creating an unequal playing field (being applicable to central and inter-state generation stations, not instate).

The current thrust of reforms is on the distribution sector, reducing losses and increasing efficiency. This might just be a precursor to privatization, but there is a goal to full electrification by 2012. This is a laudable but difficult goal, given that over half the households lack electricity today. In contrast, government publications till recently celebrated rural electrification as approaching 100%. This ignored the fact that that this measure was only at the village level, with a single connection as satisfactory criteria.

Reforms do not adequately address the issues of access and affordability, especially considering private companies entering the field.

Given India is a large nation, with 28 states, different states will and do behave differently. This dynamic, with increased competition between states (and greater devolution of powers away from the center) is a positive sign in the reforms and development process. Detailed analysis of the World Bank led Orissa reforms, which are considered to be a failure, have led to a number of lessons for other states. In Delhi, the private companies were chosen based on their bids not for the assets but in terms of how much they would reduce the losses over 5 years. Other states are moving ahead with reforms despite (often violent) protests, and this remains a major political issue at the state level.

It is important to consider that many of the policies in place today are meant to be temporary, e.g., subsidy for many classes of consumers, payments to operating companies through explicit subsidies provided in state budgets, or even the use of a single-buyer model ("TransCo") within the state. In the future, the goal is towards some form of power market, especially as indicated in the pending Electricity Bill 2001, which allows for open access to the system for all private players. However, the transition period will be quite important as it sets the benchmarks for future operation. E.g., if valuations for privatization are high, they will also be allowed higher absolute returns by the regulator.

Some of the questions that guide the analysis and are covered in the chapter include:

- Will reforms lead to economic viability of the system? Will this come through tariff increase or cost control (or both)?
- What is the best role for the regulator, and are they equipped to be fair, transparent, and independent regulators?
- If we open the sector up to privatization (distinct from retail competition), who will come in? Are there enough players? What returns do they want or expect?
- Should rapid privatization of viable (urban) areas be done quickly, or will such cherry-picking harm the overall system? To what extent should there be pooling of costs (both at the generation level, and at the retail level)? How fair and effective are such systems?

The analysis indicates several important ingredients for successful reform. For starters, initial assumptions must be realistic and accurate, as must targets for the participants. This was one of the major failures in Orissa, where the losses were significantly higher than thought, and the growth of paying customers did not materialize. In addition, there needs to be sustained government support for reforms, ranging from things varying from anti-theft legislation, to managing SEB unions, to overcoming public opposition in general. In addition, if the newly corporatized (or privatized) entities are to behave like companies, any gap between average tariff and average cost of supply must be met through explicit government subsidies (which, ideally, should be target driven and time-bound).

At the end of the day, India's reforms have thus far gone a fair ways towards the ingredients necessary to reaching the goals of increased access, efficiency, and viability, but they have not yet directly done so. These reforms, necessary but perhaps not sufficient, will be the focus of enormous effort and expenditure by the government, funding agencies, and companies in the coming decade.

1. Introduction and Background

India's electric power sector has grown substantially since independence, from 1,362 MW in 1947 to 104,918 MW in 2002, a compound annual growth rate of 8.2%. Despite this growth, the per capita consumption remains low, about 350 kWh, compared to the world average of over 2,200 kWh per capita (EIA-WEB).[2] The power utilities are massively loss-making, with a Rate of Return (RoR) estimated at *minus* 44.1% for 2001-02 (Planning Commission 2002)! In addition to low consumptions on average, there are issues of access. Rural India, which is over 72% of the population (Govt. of India 2002), in particular lacks access to power, where the majority of homes lack electricity. The power system is seen as bureaucratic, inefficient, and riddled with theft, but it is also the focus of significant government discussion, debate, and efforts. India hopes that

[2] Actually, no one knows the true per capita consumption since Transmission and Distribution (T&D) losses (which include theft, labeled "commercial losses" as opposed to "technical losses" in accounting books) are over ¼ of the total supply.

successful reforms will lead to higher capacity and economically viable expansion, powering economic growth and development.

Reforms are viewed with suspicion, and the Dabhol (Enron) episode only heightens peoples concerns with the process. The initial reforms (1991) were focused on increasing generation capacity through Independent Power Producers (IPPs), including those with foreign investment. Enron proposed a large natural gas based power plant, and secured an attractive power purchase agreement (PPA), with a guaranteed (and high) return on equity. During the negotiations phase, there were allegations of corruption, and many critics questioned the economic viability (and even need) for such IPP power. In the end, the plant was built, but its electricity proved to be cripplingly expensive. The obligations for the Maharashtra State Electricity Board (utility) have been a major reason for their dramatic financial downturn, more so than before. This thrust on generation, and even expensive IPP power, is best characterized by Homi Bhabha's oft-quoted statement, "No power is as costly as no power."[3]

As the generation-centric reforms failed to significantly add to capacity (and thus the effects on power prices, availability, and service can not really be measured), steps were taken to undergo further reforms. Critics have called these "World Bank Reforms" and charged they have not improved the situation. Other than traditional concerns from vested interests (such as labor, beneficiaries of subsidies, maintenance supply contractors, etc.) people worried how a corporate model would provide for access to electricity for the poor, and whether food prices would increase as agricultural electricity prices would likely need to increase. Privatization, seen as the end point for the reforms, is especially contentious, for not only the power sector, but for the economy as a whole. Analysts fear that many of the underlying structures and institutions are not in place for such a system. As per Stiglitz (2002), ". . .there are some important preconditions that have to be satisfied before privatization can contribute to an economy's growth. And the way privatization is accomplished makes a great deal of difference. . ."

We break this chapter down into several portions. We first present an Introduction and overview of the power system and India in general. We then present

[3] Bhabha was the architect of India's nuclear power program.

some more details about the current status, drivers for the reform process. We then analyze the various past and present reforms, looking at what their goals were and what the outcomes have been. We then attempt to study the reforms in terms of their promise, pitfalls, and limitations. It is important to recognize throughout that India is a large (and complex) country, administered federally with many states with population larger than England's. To study the reform process in more detail, we have chosen several states that are ahead in the reforms process for greater analysis. This helps compare different strategies, and highlights the different conditions (and required solutions) in different states.

2. The Indian Economy and Development

India is thought of as a sleeping tiger, a country with great potential and sizable natural resources, but one that has consistently failed to perform up to its potential. For decades after independence, India followed socialist policies, with the government responsible for many aspects of life and much of commerce, especially large-scale. The regulations and policies for such were based on the Industrial Policy Resolutions (1948 and 1956), and the Industries (Development and Regulation) Act (1951) was the underlying legislative act for state ownership and regulation of key industries (Sankar and Ramachandra 2000). Energy was no different, with the State Electricity Boards (SEBs) responsible for power development, and the government focusing on large, visible projects like dams. Nehru even declared, "Dams are the temples of modern India." Nonetheless, economic growth remained modest, close to 4 percent up until the 1980s, a growth cynically labeled the Hindu Rate of Growth.

However, 1991 saw the emergence of not only new political leadership (Prime Minister P.V. Narasimha Rao was the new head of the Congress Party, which returned to power after a gap of several years), but a financial crisis that forced the government to abandon years of controlled growth (the so called "License Raj"). A severe balance of payments crisis, with foreign exchange reserve down to just a few weeks, prompted India to liberalize its economy, including steps such as devaluing the Rupee and removing export subsidies. This period of economic liberalization and a thrust to attract Foreign

Direct Investment (FDI) maps onto reforms in the power sector in the 1990s. It also coincides with a period of increased globalization and international transfers of capital.

Politically, reforms have been advocated by most major parties, starting with the Congress Party under Rao and his Finance Minister, the economist Dr. Manmohan Singh, considered one of the architects of India's Economic Reforms. Even the Bharatiya Janata Party (BJP), which is in power today and was earlier thought to have anti-globalization and even anti-reform factions, has shown initiative to pursue infrastructure deregulation and overall reform. However, policies have not been consistent, and the goals of reform have been shifting over time, perhaps due to political compulsions. Officially expressed goals have included: disinvestment and raising capital, increasing efficiency, improving service, reducing government and bureaucracy, attracting FDI, and moving in synch with modern management and operational trends (responding to global--perhaps funding agency--pressures). At the state level, some regions (especially in the South and the West) have been more active at pursuing general reforms, though in the power sector there has been activity in much of India.

India sees itself as an emerging world power, and as the largest democracy in the world, hopes to play a major role in world affairs. It was earlier the founder of the Non-Aligned Movement, and today seeks a permanent seat on the UN Security Council. India's limitations in greater global power remain several-fold. First, its human development has been slow, with internal issues capturing much attention. Second, its global trade is limited. While energy (oil) accounts for a large fraction of imports, exports are led by agriculture and textile, gemstones and jewelry, and only more recently, IT and software. While India proclaims itself to be a major force in IT and software, it is still just a 1-2% player in the global software market. Third, India has not proven to be the great market and economic force that people had forecast on liberalization in 1991. China, with whom India always wants to compare itself economically and infrastructure-wise, has shown significantly better performance. In the power sector, China's per capita consumption is roughly two and half times higher, despite starting at similar levels in the 80s. Government officials also regularly lament India's significantly lower FDI, an order of magnitude below that in China.

Not only is global trade limited, India has significantly lower regional trade than most expanding economies. This is partially political, given its tenuous relationship with several of its neighbors, Pakistan, Bangladesh, and Sri Lanka. India imports hydropower electricity ('hydel") from Nepal (and to a small extent, Bhutan), but development of new sites has been limited (though several projects are planned and under way). However, India has not had energy cooperation with Pakistan, which earlier had surplus electricity projections (driven by guaranteed offtakes to IPPs) and wanted to sell this to India, nor have the two come together for an agreement on a gas pipeline which would traverse Pakistan to India, giving India access to large volumes of inexpensive natural gas from West and Central Asia. All in all, India has traditionally preferred domestic fuels (like its push for nuclear power), and energy security has played an underlying role in many policies.

3. The Electric Power System in India

Overview

India is the second most populous country in the world, with a population of 1,027,015,247,[4] and the largest democracy in the world. It is administered under a federal system, with many subjects under state purview, others under central, and some under "concurrent." Electricity is under the concurrent list of the constitution (Entry 38 in List III, Seventh Schedule), but like for other items under the concurrent rules, central rules often override state-level decisions. Operationally, utilities have been established at the state level (except with recent reforms), with State Electricity Boards (SEBs)[5] as the entities responsible for supplying power to consumers. Through the SEBs, the power sector has been a vehicle for social engineering, favoring particular classes of users, often at the expense of others. The government's role in the power sector is viewed as a major part of the problem, not only because of its bureaucracy, poor planning, and overstaffing, but the political interference in operations and tariff-setting, especially the heavy

[4] As of March 1, 2001 (provisional) *Govt. of India (2002). 2001 Census of India. New Delhi, Registrar General & Census Commissioner.*
[5] Some utilities were termed Electricity Departments (EDs) but the distinction is largely semantic.

subsidies for agricultural and domestic users. It is commented that the only accountability in the system was that of the politicians facing the voters, encouraging the populist pricing of electricity.

India's power sector can be broken down into roughly three periods, each of which can have more segmentation (sometimes overlapping). There were specific legislation in force or enacted that helped define these periods. Prior to Independence in 1947, most of the power was capacity was in the hands of licensees, private operators primarily focusing on urban areas. Some of these continue today, providing power to several major cities including Mumbai (Bombay), Ahmedabad, and Kolkata (Calcutta). These licensees operated under the aegis of the Indian Electricity Act of 1910, which was largely modeled on British rules. This act provided for non-discriminatory tariffs and a reasonable investment return for the Licensee.

Post Independence, the Electricity (Supply) Act of 1948 (modeled on the UK Electricity (Supply) Act of 1926 – (Choukroun 2001), provided for state-level utilities to be responsible for all new generation, transmission, and distribution, leading to the creation of the SEBs. Many existing assets were brought into the fold of the SEBs, often as the earlier licenses lapsed. These SEBs were established as extensions of the state governments, relying on them for financial support, management, and policies. Much of the financing came from state government budgets and loans, but the SEBs were expected to operate commercially. In fact, under the 1948 Act, SEBs were expected to have a Rate of Return (RoR) of not less than 3% on their asset base[6], though in practice the returns have been dramatically lower (negative) (see Table 10 on page 26 for details).

The third period can be considered since 1991, when reforms were ushered in. This chapter studies this period in detail. While the different reforms all had the effect of ending the monopoly of the vertically integrated utilities (the SEBs), the initial reforms were geared towards drawing private investment into generation (Electricity Laws (Amendment) Act, 1991). Subsequently, reforms have focused on unbundling the vertically integrated utilities—with eventual privatization of the system—and the

[6] This actually excludes "capital asset formation," essentially meaning that the returns should be on an operating basis after factoring in debt obligations.

establishment of independent Electricity Regulatory Commissions (The Electricity Regulatory Commissions Act, 1998).

Electricity Capacity and Fuel Types

Like most emerging economies, access to fuel supplies is a critical factor in determining energy and power consumption growth. India's main domestic commercial fuel is coal, but it is of poor quality. It has limited natural gas, an attractive fuel for power production, and it imports significant amounts of oil (mainly for transportation). Access to inexpensive fuel remains a critical issue for power sector viability, especially since most power purchase agreements allow for pass-through of fuel costs. In addition, most generators do no use sophisticated financial instruments for managing and hedging fuel costs.

India's current generation capacity, excluding captive power, is about 105,000 MW[7], as of March 31, 2002 (Planning Commission 2002).

Table 1: India's electricity capacity (megawatts).

Ownership/Mode	Hydro	Coal	Gas	Diesel	Wind	Nuclear	Total
State	22,636.02	36,302.00	2,661.70	582.89	62.86	-	62,245.47
Central	3,049.00	21,417.51	4,419.00	-	-	2,720.00	31,605.51
Private	576.20	4,411.38	4,082.40	551.94	1,444.60	-	11,066.52
Total	26,261.22	62,130.89	11,163.10	1,134.83	1,507.46	2,720.00	104,917.50
% of Installed Capacity	25.03	59.22	10.64	1.08	1.44	2.59	100.00

Source: Planning Commission (2002)

7 Any scholar of Indian data will know that there are many inconsistencies in data, especially government data. Every attempt has been made to show detailed calculations and assumptions, but some numbers vary between the different entities: Min. of Power, Finance, Planning Commission, States, etc. There are even variations for the same sets of numbers within a single report. We explore how this affects reform in subsequently.

These numbers are for capacity from utilities only and IPPs that sell to the utilities, and exclude captive power, or self-generation. Captive power is quite significant in India, driven by both the shortfall in available power (blackouts and brownouts), as well as the high prices many commercial/industrial users face. According to Ministry sources, captive power is approaching 15,000 MW, while industry sources and consultants estimate this to be over 20,000 MW. Of course, the different estimates vary based on the smallest size captive power they consider (smaller sizes are unregulated), and whether this is strictly for back-up or as primary supply. There are hundreds of thousands of small diesel gensets in operation in the country, but there are also numerous large generators, in the megawatt or even 100 megawatt class. This is an important issue when considering deregulation and reform, especially relating to wheeling, third-party sales, and access to transmission/distribution networks.

While thermal capacity is about 70%, its share of generation is higher, approaching 75%. Hydropower plants face generation limits and seasonal variability due to insufficient rainfall and dependence on the Monsoon. It is specifically in the dry (cropping) seasons that demand is highest. There are also limits on the possibility of expanding hydropower to its potential (assessed at 150,000 MW) due to locational difficulties (much of the potential is in the Himalayan and North-East regions, away from demand centers and costly to build), and socio-environmental concerns, notably the large displacement of people from lands that are flooded. The Sardar Sarovar Dam (Narmada Valley Project is a visible example of such controversies (World Bank 1995).[8] Government documents (for example CEA 1997; Ministry of Power 2002), lament the lack of hydropower, and advocate an ideal hydro-thermal mix closer to 40:60. It is unclear what analysis is behind this, except perhaps a cursory examination of prices, in

[8] The Government plans to proceed with this (pending legal actions), despite a negative review in 1992 from the World Bank, which withdrew its support in 1993. While ostensibly withdrawn after a Government request, the World Bank was critical of many aspects of the projects, especially relating to rehabilitation (The World Bank (1995). Learning from Narmada. Washington, DC, The World Bank (Operations Evaluation Department).

that historical prices for power from hydro projects are much lower than for thermal plants.[9]

Coal is the principal fuel for commercial production of energy and its reserves (proven, indicated, and inferred) are substantial, assessed at 234 billion tons (Ministry of Coal 2002). The annual production has increased to about 280 million tons in 2001-02, making India the third largest coal producer in the world. Of this, 216 million tons went to the power sector, making this the largest consumer of coal in the country. (Imported coal for the power sector is a very small percentage, but growing.) The increase in coal tonnage has come mainly from surface mining that contributes the majority of the output. This increase is accompanied by a marked deterioration in quality. In many collieries, the ash content has increased to 30, or sometimes even 40 percent. Washing and other preprocessing operations are considered necessary for improving the calorific value from the present low value of roughly 3,500 calories per gram, but have not found widespread use.

A major hurdle with using coal has to do with transportation, as India has limited pithead-generating stations (the tradeoff being need for investment in transmission lines). Most of the coal mines are located in Eastern India (except for the lignite mines and some of the old collieries in the South) and the coal is typically transported over long distances. For instance, the load center plant distance from the mines to stations in North India is around 700 miles and the Indian railways freight network is the only carrier. The railways are already overstretched with limited miles of track and limited freight car capacity. In 2001-02, the railways transported 223.7 million tons of coal out of a total freight carrying 473.5 million tons (Ministry of Finance 2002). Partially driven by transport bottlenecks, and also concerned with the poor quality[10] of domestic coal, some coastal power plants now opt for imported coal. The government has reduced import tariffs to 20%, making imports competitive for many regions of India.

[9] Of course, hydroprojects are attractive since, once constructed, they have very low marginal costs (no fuel costs), and they offer reasonably high levels of load control and quick start capabilities (subject to water availability). However, Indian dispatch mechanisms do not fully account for marginal cost pricing.
[10] While the ash content is high, the sulfur content is quite low, reducing the need for clean-up technologies. No Indian coal plants today incorporate Flue Gas Desulfurization (FGD) technology.

Two other issues limit a greater utilization of coal. The first concerns further mining. Further exploitation of deeper coal depends on using more underground mining and the present yield is poor, averaging less than 1 ton of output per man-shift (Ministry of Coal 2002), tens of times lower than the world average for such production. There remain issues of skilled labor and investment required to grow productivity substantially. Another issue is environmental. India has reasonably enlightened environmental laws, but the compliance at the plant level is poor because of the absence of pollution monitoring and control facilities. Even the usually rugged electrostatic precipitators fail frequently and conventional systems for flue gas clean-up, particulate removal and waste disposal are not in place in many thermal power stations, let alone more advanced systems for flue gas clean up and re-burning. The estimated annual CO_2 emissions from these plants are approaching 400 million tons, but CO_2 has not been a major decision-making factor in India (except when funding is available for alternative energy conversion technologies). Due to the high ash content, particulate emissions are particularly high, over 325,000 tons, with SPM (suspended particulate matter) readings in most metros well above safety limits (though, of course, only some fraction is attributable to power plants).

In recent years, there has been an increase in gas-fired power, utilizing Combined Cycle Gas Turbines (CCGTs), also termed Combined Cycle Combustion Turbines (CCCTs). These are attractive not only due to typical reasons such as their quick construction times, higher efficiencies, lower pollution, but also due to artifacts in Indian tariff mechanisms (Tongia and Banerjee 1998). There was a central government policy in the mid 1990s, allowing 12,000 MW of CCGT plants to be established (often built as IPP plants), and these accounted for much of the growth in capacity in this period. Because of the limited gas availability, most such plants had to use naphtha as fuel, making their power significantly more expensive. Such a thrust was despite limited gas supplies in the nation, for a Reserves to Production Ratio (R/P) of just 24.5 years, less than half the world average of 61.9 years (BP 2002). While this does not factor in recently discovered (October 2002) fields off the coast of east India by Reliance Industries of 7 trillion cubic feet (over a quarter of today's proven reserves), we must also remember that current production falls significantly short of current unmet demand.

According the public sector Gas Authority of India Limited (GAIL), in the *near term*, India can absorb a 50% increase in gas supply by converting more expensive liquid fuel based plants (fertilizer as well as power) to gas. Natural gas is the main fuel that India seeks to import for power production. While a pipeline from the Middle East/Central Asia is the cheapest solution, political obstacles prevent it from fruition (Tongia and Arunachalam 1999).[11] Indian and foreign companies have a number of ventures underway for Liquefied Natural Gas (LNG) terminals around the country. While analysts question whether all of the proposed projects will come through (or be viable, especially in light of Reliance's finds), several of them have reached financial closure or are even close to completion. However, many people (analysts, NGOs and even some government officials – private conversations) are concerned that increased dependence on LNG will lead to expensive electricity. LNG, with estimated delivered costs of $4/MMBtu[12] (or higher inland), varying with international fuel prices, is the largest portion of costs for such fueled CCGT power. In comparison, domestic gas, though limited in supply, is priced about $2.5/MMBtu. Expensive fuel costs have been one reason electricity from IPPs and other newer plants based on liquid fuel (naphtha) – built with a hope to switch over to natural gas – has been very expensive. Looking to the future, National Thermal Power Corporation (NTPC) states that with LNG priced under $3/MMBtu, it will be dispatchable. At 3-3.25 $/MMBtu, it will lead to do about 2.5 Rs./kWh generator costs, possibly the limit for what the Indian system can reasonably bear.

Nuclear power has played a modest role, at best, despite ambitious plans and a long history of nuclear power development. India, in fact, was possibly the only country involved with initial nuclear power development (in the 50s and 60s) that explicitly did not have a weapons program. However, the grand power plan that began under physicist (and friend of the First Prime Minister Nehru) Homi Bhabha and which was to have provided energy security for the country has failed to provide more than a few percent of the power for the country, in spite of significant expenditure. The worldwide isolation of

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[11] This applies for land-based or coastal shelf based pipelines which would involve cooperation with Pakistan. Deep-sea off-shore pipelines, for the distances and depths of the Arabian Sea, are not yet economically attractive.

[12] There are indications that prices might be lower due to market conditions, improvement in technology, and the bargaining power of certain consumers like the National Thermal Power Corporation (NTPC) *World Gas Intelligence (2002). Petronet LNG's RasGas Deal.* ***2002****.*

India's nuclear power program after its 1974 "peaceful nuclear explosion" combined with its choice of technology has limited the growth of the sector. Domestic natural uranium reserves are modest, about 50,000 tons, and this limits its direct usage. In fact, the "Three Phase Plan," which begins with using natural uranium in Pressurized Heavy Water Reactors (PHWRs), then involves using plutonium from the spent fuel in Fast Breeder Reactors (still not yet a commercialized technology) to produce more fissile material, and ultimately switching over to India's vast thorium[13] reserves, can not produce a significant share of electricity in the coming decades (Tongia and Arunachalam 1998). While India is pushing ahead with plans to import two Russian light water reactors (VVER class), initial reports indicate the electricity will be quite expensive. International sanctions also limit the possibility of importing nuclear reactors or fuel.[14]

Renewables are an important form of electric power and energy. In fact, if one looks at energy consumption, the primary fuel for cooking is biomass, overwhelmingly used in rural and slum areas. India prides itself on having the only Ministry dedicated to Non-conventional Energy Sources, though critics complain this is another form of expanded bureaucracy. Nonetheless, Indian policies support renewables through incentives, soft loans and the like. Wind, in particular, benefited from such incentives in the 1990s, and India saw some of the most rapid growth in windpower in the world, and its potential is estimated at 20,000 MW. Unfortunately, growth is limited to specific regions, and less appreciated is that windspeeds are lower than in many regions of Western Europe where windpower supplies substantial portions of electricity.[15] Solar power, especially through photovoltaics, is seen as a niche application, and the costs are quite high. Biomass is an interesting option for producing power, and much work is ongoing to develop such technologies. The current capacity is nearly 350 MW, but the potential for biomass is estimated to be around 19,500 MW (Bharadwaj 2002). Many

[13] Thorium, like Uranium 238 (the primary form, or *isotope*, of natural uranium, is fertile. It can not undergo a fission reaction until converted into another element through a nuclear reaction, such as in a Fast Breeder Reactor). Breeding is the process of producing more fissile material from fertile than consumed to sustain the reaction. India has the largest thorium reserves in the world, which if converted to fissile material, could provide hundreds of thousands of megawatts of power, for many, many centuries (Chidambaram, R. and C. Ganguly (1996). "Plutonium and Thorium in the Indian Nuclear Programme." Current Science **70**(1): 21-35.)

[14] The Russian deal is said to have been grandfathered.

[15] India has almost no experience with off-shore wind farms, which can improve output and performance.

cogeneration plants are coming online (megawatt class) based on burning bagasse or rice husk. However, these usually do not cater to rural electrification but rather sell back to the grid. The Ministry of Non-conventional Energy Sources has directed the SEBs to buy back all renewable power at a fixed rate, Rs. 2.25/kWh with a 5% annual escalation for 10 years (1994-95 base). This is quite an attractive rate for many project promoters, but the total scale of such renewable projects is modest, in the few hundreds of megawatts in total.

Consumption, Supply, and Demand

While Table 1 shows the capacities, the generation (driven by Plant Load Factor, or PLF) is slightly different, based on fuel type, ownership, and even location. In general, private and central plants (usually newer) have higher operating performance, and thermal plants see higher load factors than hydro. PLF is a contentious issue since profitability is related to this (discussed in more detail on page 30). In 2001-02, the generation was approximately 515 billion kWh. The consumption pattern is shown below (previous year).

Table 2: Power consumption by sector. Note that the "Other" varies over time in terms of what it does or doesn't include, e.g., municipal bodies, lighting, sewage, and rural cooperatives.

	Consumption [million kWh] (Revised Estimate 2000 - 01)	Share
Domestic	66,992	21.28%
Commercial	16,273	5.17%
Agriculture	91,737	29.14%
Industry	96,023	30.50%
Traction (Railways)	7,188	2.28%
Outside the state	3,910	1.24%
Others	32,713	10.39%
Total	314,835	100.00%

Source: Planning Commission

The first point we notice is that the sales to the different consumers differ greatly (by tens of percent) from the generation. This is because of a number of factors. Firstly, generation calculated is gross generation, an aberration of Indian accounting methods. Power plants have so-called auxiliary consumption for running their own operations. This is not only for things like lighting, but even for steam plants, physically mandatory for running the steam cycle[16]. Ignoring the very small amount of power purchased from Nepal and Bhutan (hydropower), we see that there are extremely high losses between generation and consumption, which stem from technical (T&D and transformer) losses as well as theft ("commercial losses"). These are estimated in the vicinity of 30%!

Not all consumers impact the utility or are treated equally. Looking at Table 3 below, we see that the agricultural sector pays very little, while commercial/industrial users pay significantly more, well more than average (let along marginal) costs. While we look at finance in more detail later, what is relevant is that agriculture is a significant portion of consumption,[17] and the share for industry has been declining over time (partially due to their move to captive power). Agricultural and domestic users are subsidized, while other users are charged higher prices (cross-subsidy). But, on average, utilities lose over one rupee per kWh they deliver, with a "cost of supply" of 3.50 Rs./kWh, and average tariff of Rs. 2.40/kWh (Table 7 on page 25). Comparisons of the average tariffs with other countries are meaningless given the wide sectoral variations. Domestic users in India pay relatively low prices, while industrial and commercial users pay relatively high prices, especially vis-à-vis other developing countries. In fact, most OECD countries follow more rational pricing, whereby bulk (i.e., industrial) consumers pay the lowest tariffs, and residential consumers pay the highest, which is more aligned to true economic costs.

[16] Government norms are prescriptive (performance based), stipulating coal-based plants with a cooling tower to have auxiliary consumption of 9.5% (8% if they have steam-driven pumps) and gas based plants to have 3%. CEA data indicate that the auxiliary consumption in the country on average has historically been over 7%, which is despite the low auxiliary consumption in hydro plants. This is technically an invalid accounting method since the generating plant could use steam/mechanical pumps, instead of electric pumps. Such a design would lower the gross electrical output as well as the auxiliary consumption.

[17] We will see in more detail that the exact number is disputed, due to the lack of metering and the need for SEBs to finesse losses.

Table 3: Retail power tariffs by sector

(ps/kWh)	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Actual)	1999-2000 (Prov.)	2000-01 (Revised Est.)	2001-02 (Annual Plan)
Domestic	105.7	136.2	139.1	160.7	183.1	195.6
Commercial	239.1	293.6	330.2	369.9	404.2	426.3
Agriculture	21.2	20.2	21.0	22.6	35.4	41.6
Industry	275.5	312.7	322.8	342	366.5	378.7
Traction	346.8	382.2	410.3	415.3	435.9	449.2
Outside State	151.4	138.1	163.8	190.1	187.9	194.4
Overall (average)	165.3	180.3	186.8	207	226.3	239.9

Source: Planning Commission

Similar to the difference between generation and sales, the capacity and the peak demand served vary significantly. While some is attributable to auxiliary consumption and T&D losses, other factors are at play, including derating of some generation stations, planned and unplanned availability of capacity, and operational reserve margins.

Table 4: Peak demand and supply

Year	MW Peak Demand	MW Demand Met	MW Shortage	(%) Shortfall
1996-97	63,853	52,376	11,477	18
1997-98	65,435	58,042	7,393	11.3
1998-99	67,905	58,445	9,460	13.9
1999-2000	72,669	63,691	8,978	12.4
2000-2001	78,037	67,880	10,157	13
April 2001 - Dec. 2001	77,956	68,209	9,747	12.5

Source: Ministry of Power

Table 5: Energy demand and availability (at the generation stage)

Year	(Million kWh) Requirement	(Million kWh) Availability	(Million kWh) Shortage	(%) Shortage
1996-97	413,490	365,900	47,590	11.5
1997-98	424,505	390,330	34,175	8.1
1998-99	446,584	420,235	26,349	5.9
1999-2000	480,430	450,594	29,836	6.2
2000-2001	507,216	467,400	39,816	7.8
April 2001 - Dec. 2001	388,591	360,140	28,451	7.3

Source: Ministry of Power

These tables indicate a current capacity shortfall of 12.5%. However, these are simple calculations based only on load-shedding and a slight correction for frequency deviation.[18] These do not factor in what the true demand would be if uninterrupted, quality power were available, or increased supply were given to the agricultural sector. Agricultural supply is actually throttled today, due to limits on power availability. Many states only offer agricultural power at night or off-peak hours. Given the highly subsidized agricultural tariffs, and discontinuities in supply, elasticity calculations will be misleading. Thus, we see that there is a significant shortfall in supply. Of course, lowering the T&D losses would mean that less capacity addition would be required.

Access to Supply – Thrust on Rural Electrification

The 1970s saw the first major thrust for rural electrification, starting under Indira Gandhi. India was undergoing euphoria after winning the 1971 war against Pakistan, and the government was in an aggressive, magnanimous mood. Many banks and industries were nationalized, and "electricity for all" became a policy directive under the 20 point agenda. What this and subsequent plans failed to do was clearly chart out how this was to be done. The first shortcoming was the focus on "rural electrification" based solely at a village level.

Government efforts and reports focus on rural electrification as the end-all-be-all. Officially, 86% of villages were declared electrified by March, 2001 (Planning Commission 2002), based on the 587,258 total inhabited villages as per the 1991 Census. Nine states had even declared 100 electrification of their villages, with the shortfall, some 80,000 villages, largely in Assam, Arunachal Pradesh, Bihar, Jharkhand, Madhya Pradesh, Meghalaya, Orissa, Rajasthan, Uttar Pradesh, Uttaranchal and West Bengal.

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[18] Government documents indicate that load is treated as a function of frequency, which is correct but insufficient. Even equilibrium *supply* must change with frequency to achieve the desired nominal operating frequency, i.e., 50 Hz (cycles per second). If the entire system is operating at 50 Hz (which implies supply exactly equals demand at *rated* values), a 1% steady state (non-transient) fall in frequency is caused by an increase in load (or loss of supply) of significantly more than 1%. While physics indicates that the load will be met (by plants operating at "overload"), equilibrium will be restored only by turning on additional capacity. (See standard power engineering texts like *Glover, J. D. and M. S. Sarma (2002). Power system analysis and design. Pacific Grove, CA, Wadsworth/Thomson Learning.* for more information on this topic). There are indications that the supply-demand mismatch based on frequency measurements might be very significant, implying a possible peak shortfall of tens of percent (*Tongia, R. (1998). Demand and Supply of Power in India: An Analysis of the Electric Power Grid (working paper). Electrical and Computer Engineering/Engineering and Public Policy. Pittsburgh, Carnegie Mellon University.)*

Estimates indicate that 12,000 of these might be too remote for regular electrification, and renewables are being explored for these and the Tenth Plan[19] (2002-2007) proposes to cover the remaining 62,000 villages in India.

However, what is not covered in these numbers is the access to electricity at a *household* level. The rural electrification definition requires a single connection per village only. Only 45 % of urban homes have electricity, and rural areas fare much worse, at 31% (Ministry of Power 2001), though there are indications there is a little improvement in the last few years, especially for urban supply. Clearly, steps beyond "rural electrification" are required to improve the penetration of electricity. The questions become those of affordability and logistics (the "last mile" of wiring).[20] There are several ongoing schemes to address these like *Kutir Jyoti* (House Light), which promise free hook-up and electricity for a subsistence level of power, i.e., a single light bulb.

Even if a home is electrified, the consumption per connection is quite modest, indicating that electricity has not permeated into the lifestyle (or commerce) as much as its potential. As per CEA numbers (from 1998), the average domestic connection is 0.85 kW. In fact, estimates indicate that over three-quarters of homes in most states consume less than 50 kWh/month.[21]

Growth and Plans

The capacity growth since Independence, 8.2% per annum over 55 years, has been uneven, growing in fits in the early period through large civil projects, especially dams. The growth rate has slowed down since the 1990s, and the actual capacity addition in any given year has not exceeded 5,000 MW (compared to targets of over 10,000 MW (CEA 1997). If one examines the electricity GDP elasticity (% growth in electricity capacity required for 1% growth in GDP), historical numbers show us a long-term

[19] India's development is largely based on Soviet-style 5 year plans, and a few Annual Plans in between. Critics state than too much effort is placed on Plan (laregely capital) expenditure, and not enough focus is there on operating expenditures, like maintenance, monitoring, enforcement, analysis etc.
[20] In most states, if a consumer needs a new connection, they have to pay non-trivial connection fees if the lines need to be extended. The charges vary by state.
[21] Part of this may be due to poor metering. Older, electromechanical meters have a threshold below which they fail to register consumption. Newer electronic meters only became available in the 1990s.

average number through March 1999 of 1.41 (Planning Commission 2002). In fact, casual proclamations for electricity state the requirement to be 1.5 times GDP growth. However, looking in more detail, we see that rapid growth occurred in earlier decades, and current growth in electricity capacity has been *less* than that of the GDP. While some of this might be due to sectoral changes in the economy (increased role of the service sector, for example), this also highlights the difficulties for planners when attempting to interpret correlation versus causality. Nonetheless, given the shortfall of today (Table 4), we can safely presume that 8% economic growth will require 8 – 10,000 MW increase in capacity per annum, if not more.[22]

Table 6: Electricity – GDP elasticity in India

		Elasticity
First Plan	1951-1956	3.14
Second Plan	1956-1961	3.38
Third Plan	1961-1966	5.04
Fourth Plan	1969-1974	1.85
Fifth Plan	1974-1979	1.88
Sixth Plan	1980-1985	1.39
Seventh Plan	1985-1990	1.50
Eighth Plan	1992-1997	0.97
Ninth Plan	1997-2002	0.75

Calculated and compiled from data from the Planning Commission and Ministry of Finance (Economic Surveys)

How will this growth come about, and how much will it cost? While many Plan documents claim growth targets of 40-60,000 MW for the coming 5 Year Plans, and even segment these into state, central, and private, it is unclear how such growth will be financed or sustained in the current operating environment. Assuming a target of 100,000 MW expansion, which would less than double the per capita consumption given the increase in population over 10 years, the estimated investment would be 150 billion US$, using the rule of thumb (coal-centric) that 1 MW of capacity addition requires 1 billion dollars investment for generation, and half that more for T&D. 15 billion dollars

[22] A better measure would be electricity consumption (measured quantity might have to be *generation,* kWh) vs. GDP, not capacity (MW) vs. GDP. This is particularly the case for recent periods where much of the increased production has come not through increased capacity but increased Plant Load Factors. E.g., during 1992-97, power generation increased more than the GDP because of higher PLFs.

per annum is almost 4% of the GDP, a number too high for domestic savings rates and budgets alone. This was one of the prime reasons that the government wanted foreign investment in the power sector, making this a central feature of the 1991 reforms.

Current Status of the Power System and Drivers for Reform

Finances

While the SEBs were directed to achieve a 3% RoR, this provision of the 1948 Electricity (Supply) Act did not come into force until after the 1978 Amendment of Section 59 (Kannan and Pillai 2002). Till then, utilities even failed to pay the required interest on their loans, forget the possibility of their using internal accruals for financing expansion. Instead of 3%, the actual returns were significantly poorer (Table 10). The reasons for the poor finances stem primarily from their organizational and management set-up, in that these were government entities not focusing on the bottom line. Even if they failed to be profitable, the repercussions were minimal. Electricity Boards were overstaffed, bureaucratic, and a means of largesse when it came to personnel (jobs) and contracts. However, such a system didn't allow for much new investment, either in generation, the most visible shortcoming, or in T&D networks, relatively less focused upon through Plan expenditures.

Comparing the average tariff (Table 3) to the average cost of supply shown below, we see that the losses of the utilities have been increasing over time. This is despite the substantial increase in tariffs recently, over 9.5% per annum over the 9 years shown, while inflation (Wholesale Price Index) has been about 7% (Ministry of Finance 2002). Unfortunately, the "average cost of supply"[23] has increased even more rapidly, at about 11.8%, and there are indications that this trend will continue because of higher costs of new generation units as well as increased costs for factoring in utilities' profitability (which was non-existent before). We look in more detail at future finances and relationship to the reform process later in the chapter.

[23] Average Cost of Supply as defined by the utilities is simply the total expenditure by the utility divided by total kWh sold. We explore implications of such methods later, e.g., the lack of marginal cost pricing, even long run, or the lack of economic returns.

Table 7: Cost of Supply versus Tariff

	Average Cost of Supply (ps/kWh)	Average Tariff (ps/kWh)	Shortfall (losses) (ps/kWh)	Recovery through tariff %
1992-93	128.2	105.4	22.8	82.2
1993-94	149.1	116.7	32.4	78.3
1994-95	163.4	128.0	35.4	78.3
1995-96	179.6	139.0	40.6	77.4
1996-97	215.6	165.3	50.3	76.7
1997-98	239.7	180.3	59.4	75.2
1998-99	263.1	186.8	76.3	71.0
1999-2000	305.1	207	98.1	67.8
2000-01 (RE)	327.3	226.3	101	69.1
2001-02 (AP)	349.9	239.9	110	68.6

Source: Planning Commission

Specifically, there are several trends that have contributed to these problems, some of which it is hoped that reforms will address. First, the share of consumption by agriculture has increased dramatically over time, from under 10% to almost one-third in 1998-99 (32.3%). Domestic consumption, also subsidized, has increased the second most, growing to 21.2% of the consumption today. Also worrying has been the dramatic increase in T&D losses, especially in the 1990s.

Table 8: Historical performance trends: Sectoral shares, Auxiliary consumption, and T&D losses

		1970-71	1980-81	1990-91	2000-01
Share of Industry	*Out of consumption*	70.8%	61.7%	50.1%	29.2%
Share of Agriculture	*Out of consumption*	9.2%	16.1%	23.9%	29.1%
Auxiliary Consumption	*Out of Generation*	5.6%	6.9%	7.9%	7.2%
T&D Losses (include theft)	*Out of Generation*	15.2%	17.9%	19.5%	29.9%

Calculated from data from Ministry of Power and Planning Commission.

In addition to these factors, the finances of SEBs deteriorated over time as the Power Purchase share has increased significantly, doubling in total amount in about 6 years, and growing in share to more than SEB internal generation. This power is often more expensive than internal generation, and this is certainly the case for most IPP power.

Table 9: Operating performance of SEBs and EDs. Note that T&D doesn't add up to the difference between busbar availability and sales.

		1996-97 (Actual)	1997-98 (Actual)	1998-99 (Actual)	1999-2000 (Prov.)	2000-01 (RE)	2001-02 (AP)
Gross Generation	MkWh	252,016	243,611	258,283	260,402	275,932	284,722
Auxiliary Consumption	%	6.56	7.14	7.03	7.19	7.18	7.05
Power Purchase	MkWh	166,620	176,342	198,502	267,655	295,371	325,071
Net availability at Busbar	MkWh	360,509	376,707	402,759	431,420	471,020	504,378
T&D Losses	%	24.6	24.0	24.9	30.8	29.9	27.8
Sales	MkWh	268,031	283,650	296,136	298,649	314,835	340,061

Source: Planning Commission

The implication of these trends can be seen in the finances of the utilities.

Table 10: Financial Status of the SEBs/Utilities

(Rs. crore)			1991-92	2000-01* (provisional)	2001-02 (RE)	2002-03 (AP)
A.		Gross Subsidy involved on account of sale of electricity to:				
(i)						
	(a)	Agriculture	5,938	24,074	25,571	26,959
	(b)	Domestic	1,310	9,968	10,894	11,651
	(c)	Inter-State Sales	201	386	247	226
		Total	*7,449*	*34,428*	*36,713*	*38,836*
(ii)		Subventions recd. from State Govts.	2,045	8,820	10,099	7,981
(iii)		Net Subsidy	5,404	25,607	26,613	30,855
(iv)		Surplus generated by sales to other sectors	2,173	3,435	3,615	7,499
(v)		*Uncovered Subsidy*	*3,231*	*22,172*	*22,999*	*23,356*
B.		Commercial losses*				
(i)		Commercial losses (excluding subsidy)	4,117	25,395	27,306	24,321
(ii)		Commercial losses (including subsidy)	N.A.	16,575	17,207	16,340
C.		Revenue Mobilization				
(i)		Rate of Return (RoR)	-12.7%	-41.8%	-39.5%	-32.1%
(ii)		Additional Revenue Mobilization from:				
	(a)	Achieving 3% RoR[24]	4,959	27,217	29,404	26,226
	(b)	Introducing 50 paise/unit from agriculture	2,176	1,638	1,350	1,330

1 crore = 10,000,000 (4.8 crore ≈ 1 million US$, today) AP = Annual Plan RE = Revised Estimate
* Commercial losses do not equal uncovered subsidy due to other operations by the SEBs
Source: Ministry of Finance (2002)

[24] Additional Revenue Mobilization is a rather silly accounting mechanism seen in many government publications, as it ignores causality! How does one magically "achieve 3% RoR?"

While nominally, states are supposed to give explicit subsidies to the SEBs to cover the subsidies offered to agriculture and domestic sectors, these are often book payments that never quite take place. SEBs are supposed to pay the state interest (and earnings returns) for the investments undertaken, as well as Electricity Duty. This would, historically, be squared against the subvention portion. However, these two amounts are no longer comparable, and SEBs have not received compensation for their loss-making operations. Politically, utilities had found it difficult – if not impossible – to raise prices for many classes of consumers.

The gross subsidy (before the cross-subsidy from explicitly overcharging commercial/industrial users) is around 8 billion dollars annually, around 2 percent of the GDP! This is clearly unsustainable. Another problem at an operating level is the high built-up debt (and outstanding dues) of many entities. The SEBs are unable to pay the power producers, such as a coal power generation company, typically a Public Sector Unit (PSU). They in turn, delay payments to Coal India Limited, another PSU. Coal India then delays payments to the Indian Railways. This is a vicious path that must be addressed in the reforms process. The total dues are given below.

Table 11: Total outstanding dues (including surcharges) by state utilities to Central PSUs (Rs. crore)

	Rural Electrification Corp.	Natl. Thermal Power Corp.	North-Eastern Electric Power Corp.	Damodar Valley Corp.	National Hydroelectric Power Corp.	Power Finance Corp.	PowerGrid Corp. India Ltd.
Total Dues (as of Feb. 28, 2002)	3,895.79	22,065.78	1,233.99	3,067.82	2,221.53	235.09	1,415.30
Grand Total	34,135.30						

Source: Planning Commission (2002)

In terms of state budgets, we see that subventions (line-item subsidies) are quite substantial (but vary across the states). These have also plateaued, largely due to financial difficulties faced by the states. Looking at overall state budgets, the revenue deficit increased from Rs. 53.1 billion (0.99% of GDP) in 1990-01 to Rs. 404.9 billion

(2.30% of GDP) in 1998-99. In comparison, the losses of the 19 major SEBs increased from 5% of the revenue receipts in 1992-93 to 6.5% in 1998-99 (Ahluwalia and Bhatiani 2000). If the opportunity cost of such losses is added (nominally, SEBs should earn a return), then the losses in 1998-99 increased to 187 billion rupees, about 10% of state revenue receipts.

To show an example, in the state of Gujarat, the 2000-01 budget was 23,717 crore rupees, but the actual expenditure was higher by Rs. 7,727 crore.[25] But, since the revenues were also higher, the total deficit was 1,501 crore Rs. Power sector subventions (Table 12) contributed significantly to this (Gujarat also faced a major natural disaster, affecting the budget). Nonetheless, we see that power sector subventions account for several percent of the state budget, and even over 1% of the Gross State Domestic Product (GSDP). This is true across most of India, and the numbers in Table 12 exclude Plan expenditure for the power sector (capital expenditures).

[25] Gujarat State Government report: Macro Overview of Economy.

Table 12: Subventions (subsidy) received from the states

(Rupees crore)	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02
SEBs	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Provisional	(Revised Estimate)	(Annual Plan)
Andhra Pradesh	-	0.1	944.1	1,259.1	850.4	-	2,549.2	3,064.4	1,626.3	1,626.3
Assam	-	-	0.1	0.5	-	-	-	-	-	-
Bihar	-	-	-	-	-	-	-	-	-	-
Delhi (DVB)	-	-	-	-	-	-	-	-	-	-
Gujarat	619.0	585.0	656.0	1,111.0	1,063.0	1,483.0	1,673.0	1,277.0	1,316.0	1,356.0
Haryana	35.0	60.0	455.0	599.7	641.7	732.4	364.0	412.0	412.0	412.0
Himachal Pradesh	-	-	-	0.1	-	-	-	-	-	-
Jammu & Kashmir	-	-	-	-	-	-	-	-	-	-
Karnataka	51.6	35.8	207.2	553.6	705.8	380.1	913.9	1,050.6	1,751.2	2,426.5
Kerala	-	-	8.6	53.2	31.5	-	205.8	464.7	781.0	909.0
Madhya Pradesh	380.1	415.2	514.7	593.9	300.4	245.4	120.5	433.1	464.4	498.9
Maharashtra	-	-	-	629.9	258.6	305.6	355.1	2,084.2	-	-
Meghalaya	6.5	7.0	7.0	8.0	8.5	9.0	9.5	9.3	10.5	11.0
Orissa	1,390.0	226.0	161.0	257.6	11.4	5.3	-	-	4.0	-
Punjab	-	-	-	-	-	-	-	403.7	-	-
Rajasthan (Transco.)	281.6	424.9	489.3	510.7	560.8	704.9	1,196.5	1,766.1	-	-
Tamil Nadu	350.1	527.1	350.1	415.9	586.5	570.1	1,076.1	250.0	250.0	250.0
UP (PowerCorp)	-	-	1,237.0	1,517.0	1,557.0	1,838.9	1,838.9	-	800.0	800.0
West Bengal	68.1	73.2	97.1	81.7	55.0	90.0	49.2	49.4	50.0	50.0
Total:	3,182.0	2,354.3	5,127.1	7,592.0	6,630.6	6,364.8	10,351.6	11,264.5	7,465.3	8,339.6

Source: Planning Commission

Operations, Expenditures and Investments

Given the poor finances of the utilities, they find themselves handling day-to-day operations and do not engage in long-term planning. Planning, in fact, has lain in the hands of other agencies and institutions, like the Planning Commission, while utilities spend much of their time dealing with "firefighting." Dealing with labor issues, blackouts, and public safety emergencies (and politicians) consumes much of the time of utility management.[26]

Labor is a substantial cost for the utilities, despite the relatively low wages in India. This is because of the very large number of personnel, measured through various metrics like employees per megawatt, kW-hr or number of customers. While the absolute numbers are declining over time, this is from an enormously high base. Just looking at Establishment and Administration (largely salaries) as a percent of total costs (from the "cost of supply" calculations), in 1998-99 it stood at 14%![27] In comparison, in the US, establishment and administration costs are only a few percent. The SEBs have more than an order of magnitude greater staff than US utilities.

In terms of Central Plan expenditures, 2001-02 has a budgeted amount of Rs. 27,842.67 crore[28], which is only 12.19% of the total plan outlay (Planning Commission 2002). This is a reduction from recent years, where it was over 19% during the beginning of the 1990s. (As an aside, the actual expenditure is often lagging the outlay due to incompletion of or delays with some activities). One positive trend in this is that the relative outlays for T&D and renovation and modernization (of existing capacity) have increased significantly, from 28.0% and 2.0% in 1992-97 (8th Plan) to 36.25% and 6.16%, respectively, in 2001. Of course, some of the reduction in Generation expenditure is likely due to the thrust given for private investment in generation. Nonetheless, there is the realization that improving the operation of the grid will be necessary for turning the power sector around.

Plant Load Factors (PLF)

While capacity has not increased substantially in recent years, the generation has improved somewhat more, largely because of the increased output from generators, with some increase coming from increased inter-region transfers. We can see below that the

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[26] Personal communication (unattributable).
[27] Actually, the calculations for the SEBs appear to exclude the embedded Establishment & Administration charges for the generating companies, whose total costs are seen only as "purchased power" costs. This would make the E&A total percentage even higher.
[28] Excludes Jharkhand State.

PLFs have improved markedly. While state plants have shown the most improvement, they still lag behind central and private plants, which are both operating above 74% PLF.

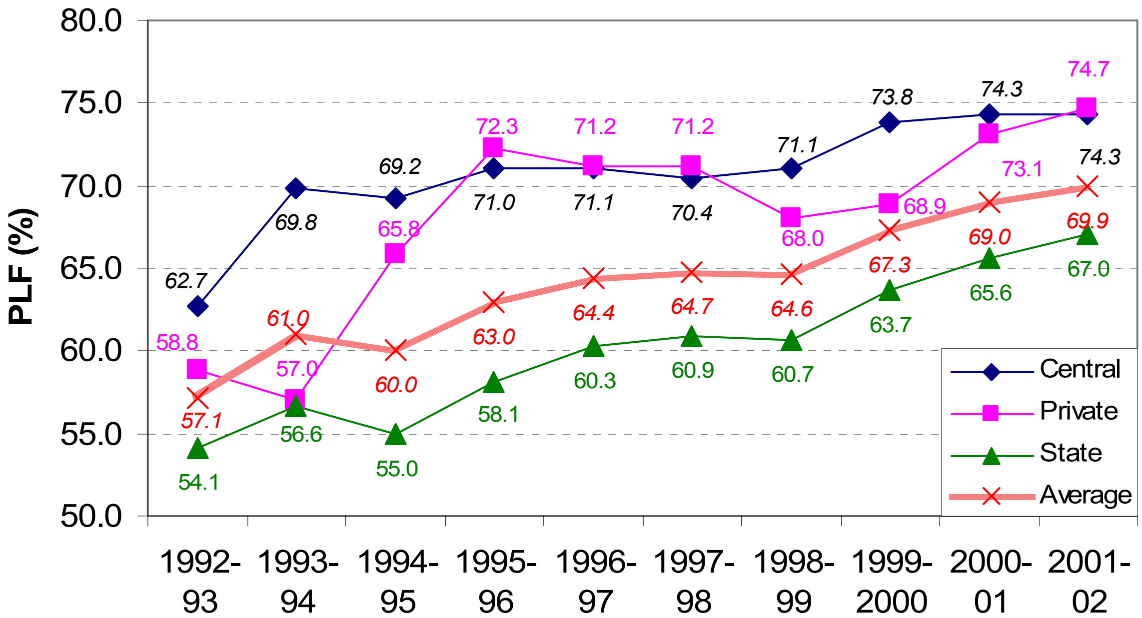


Figure 1: Plant Load Factor (PLF) of thermal plants
Source: Planning Commission data

Many government documents show this as a positive trend, but a deeper analysis shows several issues. For starters, PLF is can not increase indefinitely, since there must be lower demand periods in a day when reduced output is required. What is disturbing is that official documents treat such normal backing down as "unplanned outages," as if all thermal plants would operate at almost 100% PLF if possible. In fact, the metric of availability indicates reasonably healthy performance, with NTPC (the central PSU) showing an availability of close to 90%. In addition, increased output from thermal plants comes with increased marginal costs. As per the Planning Commission (2002), "The gap between the plant availability and plant load factor (PLF) indicates that though the plants are available at 80% of the time, they are forced to back down in some of the states, particularly in eastern region, during the off-peak hours due to lower demand. Efforts need to be made to address this issue and utilize the plants optimally." (!)

A deeper problem lies with the mistaken approach that PLF is the appropriate measure of performance. PLF of a system should mirror the demand. Given that the peak (capacity) shortfall is lower than the average (energy) shortfall, as the system improves, it is only natural that overall PLF should fall. In the US, the system-wide PLF is only about 53% (EIA-WEB updated periodically). One causative mechanism for the problem is that the tariffs for generators have been based on a normative PLF, 68.5% (for thermal stations). As long as they output this amount, they will make their stipulated returns, and increased output gives them a bonus (Tongia and Banerjee 1998). In fact, some regions are contracting for guaranteed PLFs of 80% (and asking for take-or-pay power purchase agreements), citing energy shortfalls. In a well-run system, dispatch rules should indicate which generators are operating based on real-time load. These should be economic decisions based on marginal costs, ideally. Instead, in India, contractual or political issues come up, and some operators refuse to back down, since that affects their profits (and "performance" metrics). This is why the frequency of the system can often go over 50 Hz, especially at night. What is required for such decisions to be made is a load duration curve, something utilities in India lack. UK numbers (Figure 2 below) indicate that all generators should not expect to operate at the same (high) PLF. The baseload plants would be nuclear power, coal, some CCGT (if cheap gas is available), and hydropower (if extensive water is available). Peaking power would come from hydropower (especially pumped storage), oil, and simple cycle gas turbines. Intermediate power would come from a combination of gas and coal, depending on the situation. One difficult issue becomes comparing long term vs. short term marginal costs (Ellerman 1996). Once built, coal power is often cheaper than gas power, but gas plants cost much less to construct. So, higher load factors are often the norm for coal based plants, especially since these have long operating lead (ramp-up) times to come to full power. Unfortunately, correct methodologies are not followed when choosing gas versus coal plants in India, nor are correct planning methods used for PLFs for pricing purposes.

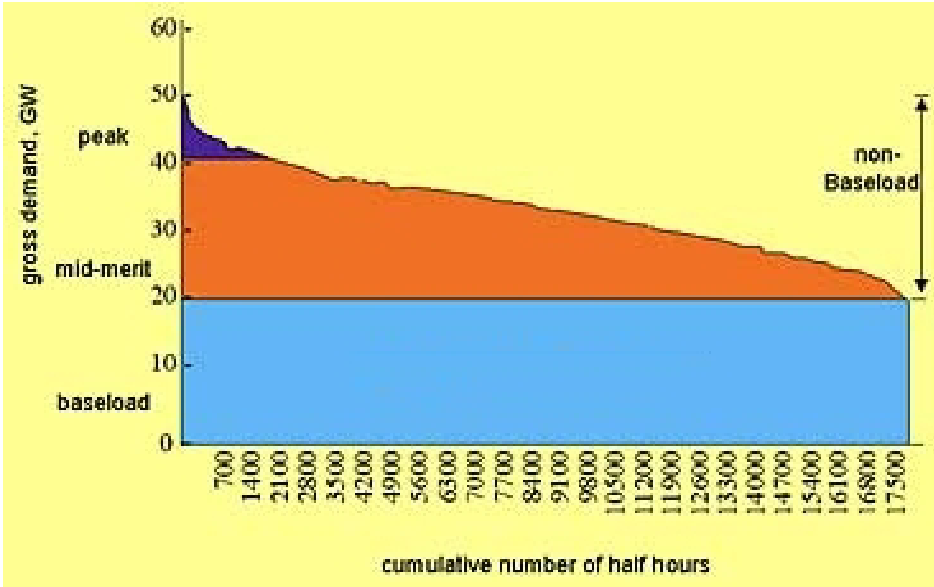


Figure 2: 1997 Load Duration Curve for the UK (from National Power)
Source: (Burdon 1998)

In response to some of these issues, there is a recent move towards Availability Based Tariff (ABT), instead of the previous PLF based two-part tariff (fixed costs recovered at 68.5% PLF and variable costs at actuals). ABT would give credit to generators even when they are asked to back down, and would penalize all groups (generators as well as consuming states) for deviating from the prescribed norms (supply or drawal). However, as the availability of a modern thermal plant is expected to be high (and invariably higher than the currently prescribed norms), this doesn't help the pricing of the power. There are also other problems with ABT, briefly discussed later.

Quality of Electricity

Utilities in India do not publish standard performance statistics, as they would be an order or two of magnitude behind acceptable norms. Standard metrics include 1) SAIFI (System Average Interruption Frequency Index), the average number of interruptions experienced by customers per year, 2) SAIDI (System Average Interruption Duration Index), the average number of interruption minutes experienced by customers per year, or 3) CAIDI (Customer Average Interruption Duration Index), the average duration of an interruption, equal to SAIDI divided by SAIFI. The US had averages of 1)

SAIFI – 1.26 interruptions per year, 2) SAIDI – 117 minutes of interruption per year, and 3) CAIDI – 88 minutes average duration per interruption (Brown and Marshall 2001). Clearly, the distributions have strong skew, since most people in the US don't experience nearly two hours of downtime; some just experience much longer downtimes, especially in the winter due to storms. Instead of these, India uses a measure called loss of load probability (LOLP). LOLP is often allowed in the percent range, and even this is not met.

In India, load-shedding is common in most of the country, with even the capital New Delhi facing several hours of rolling (controlled) outages per day during peak months. (This, of course, is why the elite and many commercial establishments rely on back-up power). Agricultural supply is significantly curtailed, and the total downtime is likely to be measured in days, not minutes.

One exception is Mumbai, which has largely had good power supply (and quality supply). The reasons have been not only institutional, with non-SEB utilities (Tatas, a large private conglomerate, BSES, an established private player, and BEST, a municipal undertaking) providing power, but also technical. The city has enough capacity available to it internally, and can "island" itself from the rest of the state[29] to ensure quality supply. However, such a fix will not be available in other parts of the country, making privatization more difficult.

In addition to lack of supply, the quality of the supplied power is also quite lacking. Even the standards themselves are outdated, based on the Indian Electricity Rules of 1956. Voltage for low-voltage (retail) consumers is allowed to deviate by 6% while the frequency is allowed to deviate by 3%.[30] In practice, the voltage can fall by much more than 20%, especially for long rural feeders, while the frequency can dip by

[29] AC power is synchronous and connected. Normally, disturbances in other parts of the network affect the rest of the connected grid. Synchronous systems are those that are connected such that the frequency is essentially the same throughout the system, i.e., it acts as one large coupled system.

[30] As indicated in Footnote 18, a 3% deviation in frequency is very substantial, and damaging to equipment like motors. A 2002 visit to a regional control room showed their status to be "normal" when the frequency was 48.15 Hz! This indicates how little appreciation there is for this critical parameter. While Indian frequency is allowed to fall to 48.5 Hz as per the norms, US norms are to control it within .02 Hz!

more than 4%.[31] Also, the frequency often goes over the rated at night or off-peak periods, indicating very poor grid discipline and management. While there are some attempts to improve the quality of power, e.g., correcting for power factor deviation (increase in reactive power—see Footnote 31 on page 35 for more information on this), the achievement has been much lower than the announced targets by far.

Agriculture in particular faces bad quality power. A major World Bank (2001) study indicates that the poor quality power causes an implicit cost to the farmer much greater than the charged tariff. This is because of the damage to pumpsets, and the almost annual rewinding these require. There are also losses due to frequent distribution transformer breakdowns and associated lack of supply.

Agriculture

The agricultural sector consumes almost a third of the power in the country, and pays for less than 5%. Actually, if one factors in the losses, in that long rural feeders lead to the highest losses, then the burden is greater. The skew is actually worse than stated in government books since the "cost of supply" number quoted everywhere is an average number. Sectoral variations in cost of supply are not factored in. To serve a high voltage bulk consumer costs a utility much less than to serve an intermittent pump in a remote rural location. Estimates by the author posit that the difference between some classes of users can be 30% or more.

There are actually indications that the agricultural consumption can not really be as high as stated, and the utilities simply fudge the numbers as they find convenient (Dixit and Sant 1997). This is because the agricultural consumption is largely unmetered. Power leaving a rural substation either goes to metered consumers (domestic, commercial, etc.), pumpsets (unmetered), or is lost (technical losses plus commercial losses, i.e., theft). We thus have 3 unknowns to calculate for using just one equation (knowing the energy passing through the substation and to metered users). A less well appreciated fact is that even the technical losses are quite high. Distribution technical

[31] Voltage falls due to a mismatch in load and supplied reactive power, while frequency falls due to a reduction in supplied real power. Real power is that portion capable of doing work, where the current is in phase with the voltage. Reactive power has voltage and current out of phase, and is seen for inductive loads like pumpsets. Regular electricity supply includes some fraction reactive power.

losses alone have been calculated to be in the 10% range for rural areas (Bharadwaj and Tongia 2003), with estimates for transmission losses at above 8%. This is compared to the total T *and* D losses of the US of around 8%.

There are several important reasons and stories as to why agriculture's share has increased so dramatically, why they pay so little, and why the consumption is unmetered. India is an agricultural nation, with one third of the GDP coming from this sector, but over two-thirds of the population depending on it for their livelihood. After overcoming dramatic famines in the 1960s (and succeeding with the Green Revolution), agriculture has been a priority for the government. Given poverty levels in the country, food prices are controlled, and many agricultural inputs are subsidized (fertilizer, water, finance, etc.) Food is often sold through government distribution shops ("Ration Shops") at administered prices. To increase the yield of food irrigated water became a necessity, as the Monsoons would be erratic and time limited. Surface irrigation didn't expand nearly as much, and the bulk of the expansion came through underground irrigation (pumpsets). This allowed farmers to increase the number of sowing seasons, and increasing their yield dramatically. As canal based water was provided nearly free (heavily subsidized), there were demands and calculations to keep electricity nearly free for agricultural use. (While some farmers used diesel pumpsets, these are often larger landowners.) However, the combination of administered pricing and cheap electricity led to changes in cropping patterns, increasing not only the number of growing seasons (a plus) but also changing the crops grown (a minus). Dry areas, like the Telangana Region of central Andhra Pradesh (around the capital Hyderabad), which had traditionally grown coarse grain, switched to rice production, a very water intensive crop. Throughout the country, the heavy use of groundwater, not only for agriculture but also for drinking water, is leading to rapidly falling water tables,[32] as much as several meters per year in some places (Padmanaban and Totino 2001). This is a major area for concern for India in the coming decades, especially in the Western and Central regions of the country. Has cheap power for agriculture had its desired effects? Economic Survey data indicate that the agricultural productivity growth rate was higher in the 1980s than in the 1990s, with yield growth rates more than double. This counters the direct causality link (but further

[32] Falling water tables also increase pumpset loads.

analysis would be needed to account for crop pattern changes, technology, access to financing and other factors).

Given India is a democracy, catering to this large agricultural vote bank has also been a major reason for the largesse it enjoys, combined with their strong lobbying power. The government (politicians) has traditionally been able to dictate prices enjoyed by the sector. Political competition has even seen some states competing to give free power (or promising to do so) for upcoming elections. One of the decisions taken relatively early[33] on was to charge consumers flat rates based on the (nameplate) horsepower rating, instead of consumption (with some states even offering free power). Of course, some farmers would understate their capacity, leading to falling voltage levels and frequent transformer overloads and burnouts. The charges for capacity lead to the effective prices shown in Table 3. There are specific known instances where single persons decisions have led to the removal of meters from agricultural pumpsets in states, ostensibly to save money since the tariffs were based on capacity. Unfortunately, this has become one of the gravest policy errors in the power sector. Today, agricultural consumption is the albatross around the utilities' neck. Without meters, utilities do not even know how much this sector consumes, let alone move to pricing their consumption correctly. Installing meters remains politically difficult, with SEB personnel fearing for their lives when they try and install meters. Farmers typically destroy the meters, and circumvent any attempts to regulate their supply. In addition, it is a logistical challenge, considering there are nearly 14 million pumpsets (authorized plus unauthorized) in the country.

There are other issues with agricultural power pricing, with evidenc that subsidized power really helps the rich farmers, who own larger plots of land (World Bank 2001). Subsistence farmers often lack land, or the resources to invest in pumpsets, or consume smaller amounts of water, which makes flat-rate pricing regressive. Additionally, such input-side subsidies have lacked a time-frame for expiration (making

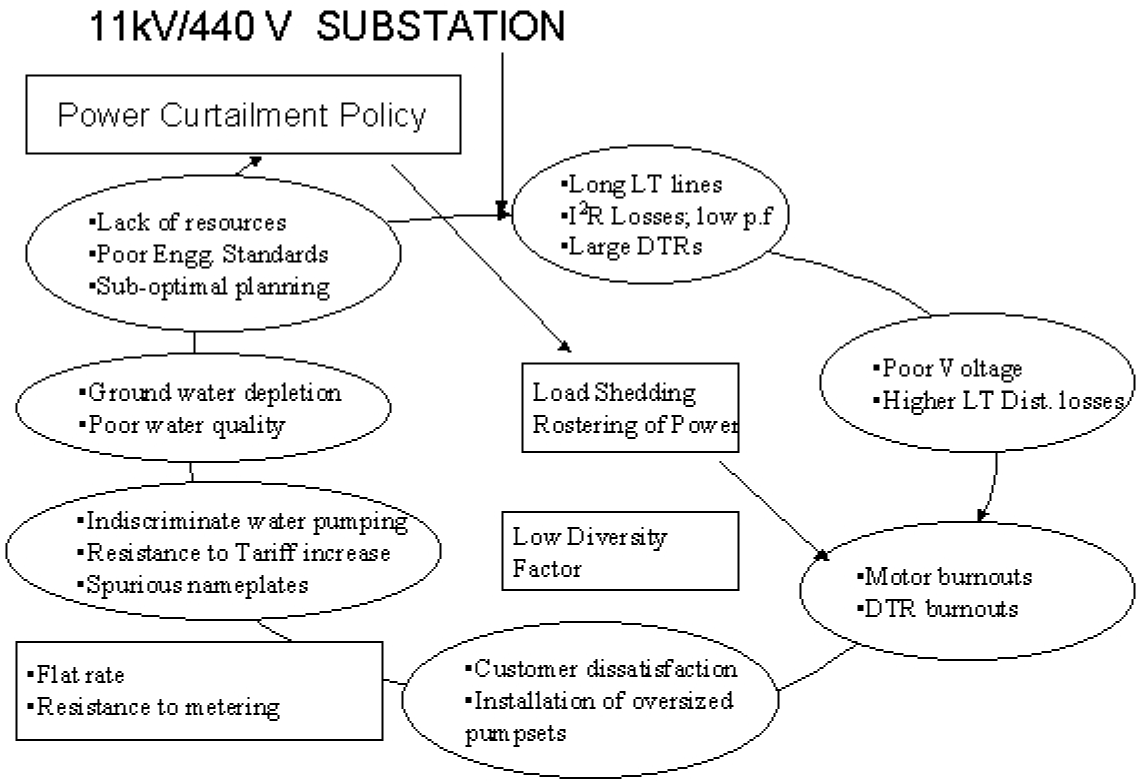
[33] The Congress Party promised this as an electoral plank in the 1977 state elections in Andhra Pradesh. This is reportedly the first occurrence of agricultural subsidies as a electoral tool (*Dubash, N. K. and S. C. Rajan (2001). The Politics of Power Sector Reform in India. Washington, DC, World Resources Institute.*)

their removal difficult), as well as mechanisms for categorizing users into being worthy of subsidies or not.

To fix the problems with the agricultural sector, water (as well as other inputs like fertilizers) should be priced appropriately. However, that would raise the output food prices, and critics worry about the impact on the poor. However, even if the price of food at the farm increased, retail prices would not increase as much since much of the final cost is transportation, transactional, and along the marketing chain. In addition, it might be possible to subsidize the poorer consumers directly, but keeping the pricing signals (inputs) seen by the farmers at economic cost, leading to more efficient outcomes. A deeper analysis of the agricultural sector, input pricing, and subsidies is beyond the scope of this chapter. Nonetheless, it is important to understand the impact on the power sector. Given that farmers get very cheap power, their incentive is to buy the least expensive (and correspondingly least efficient) pumpset. They also overuse water, leading to soil runoff problems and water saturation. Part of this is driven by the erratic supply. They often just leave the pumpset on, hoping power supply comes on at night.

Agricultural consumers have been asked to pay more for their electricity. They counter that they must compete with farmers who receive nearly fully subsidized canal-based water, which contributes a minority but still substantial portion of irrigation across the country. They have said they really don't want the electricity, but rather the water. Experiments to providing water as the service rather than the electricity are being tried by some utilities (in Andhra Pradesh), but there is a long way to go for such a model. In addition, they complain that the quality of electricity is palpably poor, and they don't receive enough hours of supply as promised.

Figure 3: The vicious cycle in energy and water use in agriculture



LT = Low Tension; DTR = Distribution Transformer; p.f. = power factor; I^2R Losses = Heat losses

Source: (Padmanaban and Totino)

Structure of the Industry

The structure of the Indian power sector is changing rapidly with ongoing reforms, but much of the challenges facing this transition stem from its historical buildout. Since the establishment of the SEBs, the states built up much of the capacity up to the 1970s, with the exception of nuclear power. Some major hydroprojects were built to service more than one state, and these were built up as one-off projects or separate corporations, like the Damodar Valley Corporation (modeled somewhat on the Tennessee Valley Authority). One major shift was the rise of central bodies in the power sector by the 1970s.

Players (Pre-reform Focus)

National Thermal Power Corporation (NTPC) was incorporated in 1975 as a Central PSU, to enhance thermal power generation (largely coal). It is considered a professional and efficient organization, and has grown today 20,435 MW (excluding Joint Venture capacity of 314 MW), making it the 6th largest thermal generating company in the world. Its return on capital employed was over 11.9%, which is better than most utilities in the world (not all capital is equity, as, worldwide, most utilities are leveraged, i.e., carry debt). NTPC's unaudited financials for 2001-02 (off their website) indicate that revenues were Rs. 17, 911.04 crore and net profit was Rs 3,539.62 crore. NTPC's thermal plants had a PLF of 81.1% (84.3% excluding the Eastern Region, which has low demand and limited export capability) (Ministry of Power 2002). NTPC will be a key player in India's power sector, and is aggressively looking to expand its businesses, moving beyond not only thermal projects into hydropower, but also power trading and consultancy, and is even pursuing the distribution business.

The National Hydroelectric Power Corp. (NHPC) was established in 1975 to build large hydropower projects, but the growth has slowed and their installed capacity today is only 2,175 MW (Planning Commission 2002). The North-Eastern Electric Power Corporation, Ltd. (NEEPCO) was established in 1976 to develop power generation (hydro and thermal) in the northeastern region of the country, one that lags behind in terms of infrastructure development. NEEPCO contributes 700 MW of capacity in the region, which is 40% of the total. This company is profitable, but its role will remain regional and niche.

Central generating stations (or others that cater to multiple states) see their power sent over transmission owned by the PowerGrid Corp. of India Limited (PGCIL). PGCIL was set up to help build up a national grid, and was actually a spin-off from NTPC (being incorporated in 1989 but beginning management of in 1991). PGCIL is responsible for all interstate power transfers, handling some 40% of the country's power. The states (or their new corporations) still own their internal transmission. Generators like Independent Power Producers (IPPs) are either purely in-state, or they too rely on PGCIL for transmission of their power. It is (self) reported to be the largest transmission company in the world, with over 40,000 circuitous km of transmission lines and connection to one-third of the capacity in the country. In 2000-01, it had profits of Rs. 742 crore (≈US$ 165 M) on revenues of Rs. 2,683 crore (≈US$ 596 M). Thus, it saw a profit of almost 28% (!), which is quite high for a transmission company, especially one not operating in a market environment and able to use sophisticated financial tools. The focus today is on extending Extra High Voltage (EHV) transmission and strengthening inter-region transfers. It is also actively pursuing a telecom venture (as a Joint Venture), utilizing extensive optical fiber that was laid alongside its Rights of Way (for SCADA[34] purposes). PowerGrid's role is likely to expand significantly as a new Grid Code comes into force, envisioning greater use of transmission facilities.

The Power Trading Corporation (PTC) was established in 1999, and 8% equity is to be held by each of NTPC, PGCIL, PFC, and NHPC (the first three have paid up as of 2002). Other shares are available to financial institutions and investors. Its vision is to help set up a power market and to "correct the distortions in the market." The plan is to have mechanisms to trade electricity, but these would be paper trades since PTC is not a facilities operating company. Some of its trades are designed to be facilitated through the web, making this more like a B2B transaction than a spot market. The volume of transaction is very low, with a sizable fraction made of international (hydro) purchases resold in India. As per its website, it charges five paise/kWh (negotiable) for the transaction, and in the current (2002-03) financial year, it has traded over 3 billion kWh thus far. It remains to be seen what the impact of this company will be, not because of its own limitations, but rather the structure of the sector where most projects operate on bilaterals, with Power Purchase Agreements, and where there is little surplus capacity.

The Rural Electrification Corporation (REC) was established in 1969 after the famines of the 1960s, with a mission to "facilitate availability of electricity for accelerated growth and for enrichment of quality of life of rural and semi-urban population." However, it is not entirely modeled on the erstwhile US Rural Electrification Administration. REC provides loans for a variety of power sector projects, not only rural electrification but also specific projects like pumpsets, increasing

[34] Supervisory Control and Data Acquisition

the penetration density, etc. These are provided only to utilities, not end-users, and have terms of 7-10 years, at 10-12% rate. As of March 31, 2002, it had cumulatively disbursed loans of Rs. 24,687 crore to SEBs and utilities. These loans are at or just below market rates for infrastructure projects, but lower than what many project promoters would find available independently. In effect, REC helps consolidate and transfer risks, since the bulk of its own finances come from secured and unsecured loans, including from the Govt. of India. In 2001-02, REC sanctioned Rs. 6,764 crore of loans, and disbursed 4,722 crore of loans, with a pre-tax, pre-depreciation profit of 503 crore Rupees.

The Power Finance Corporation (PFC) was established in 1986 with the goal of becoming the primary development financial institution for power projects in the country, for central, state, and municipal PSUs, and is wholly owned by the Govt. of India. The funds from PFC are meant to be in addition to Plan expenditure, and are to be given on the merits of individual projects. PFC sanctioned 8,506 crore Rs. of projects in 2001-02, of which 5,150 Cr. were disbursed, and its profits before taxes were Rs. 950.4 crore. PFCs sources of money include domestic debt (60% in 2001-02), operating capital, paid-up capital, bonds, term loans, and foreign currency loans. Most loans are given at attractive rates (lower than bank lending rates by several percent). Despite its strong performance, PFC can not meet the entire anticipated needs of the power sector as per its growth plans, even for government bodies.

Operations and Regulation

Operationally, India today does not yet have a national, synchronous grid. There are 5 regions (Northern, Eastern, North-Eastern, Southern, and Western) each operating somewhat independently. Inter-region transfers are primarily through High Voltage DC (HVDC) links, which overcome synchronization issues. Nonetheless, inter-region transfers are modest, partially because of limited surplus in any one region (and the entire country faces nearly coincident loads – one time zone), and also because of the small size of the tie-lines between the regions. Each region operates under a Regional Electricity Board, which is responsible for load dispatch decisions through Regional Load Dispatch[35] Centers).

[35] Also termed "Despatch"

Most decision-making comes under the Ministry of Power, with the Planning Commission involved in financing Plan expenditures. There is a little known Central Electricity Board, a statutory body as per Section 36-A of the Indian Electricity Act, 1910, which is empowered to make rules to regulate generation, transmission, supply and use of electrical energy and generally to carry out the purposes and objects of the Act. Functionally (and for execution), the activities of the Board are managed through a Secretariat provided by Central Electricity Authority (CEA). The Board meets at least once in year to consider amendments/additions to the rules (Ministry of Power 2002).

The Central Electricity Authority is the operating body that has been responsible for much of the regulatory norms in force today, especially prior to the establishment of the Central Electricity Regulatory Commission (CERC) in 1998. The CEA was established in 1951 as a part time statutory body, and became a full-time body in 1975. It helps the ministry of power with all technical, economic, and operation tasks relating to the power sector, viz., techno-economic operation of the Indian power system. It has been the body responsible for techno-economic clearances (TEC) for all power projects above a certain size. After the 1998 reforms, the regulatory responsibilities of CEA have been shifted to CERC. We study the regulatory commissions in more detail shortly.

If a generator (IPP or PSU) wants to build a power project, it comes to the CEA for techno-economic clearance. CEA is attempting to coordinate with other bodies whose clearance is required, e.g., Ministry of Forests and Environment, (become a one-stop shop), but this has not quite materialized. There are attempts to reduce the need for TEC to streamline the process, e.g., increasing the threshold below which CEA clearance is not required. In fact, the pending 2001 Electricity Bill indicates a removal of the need for CEA TEC. There also remain issues of overlapping and even conflicting regulations from CEA and CERC.

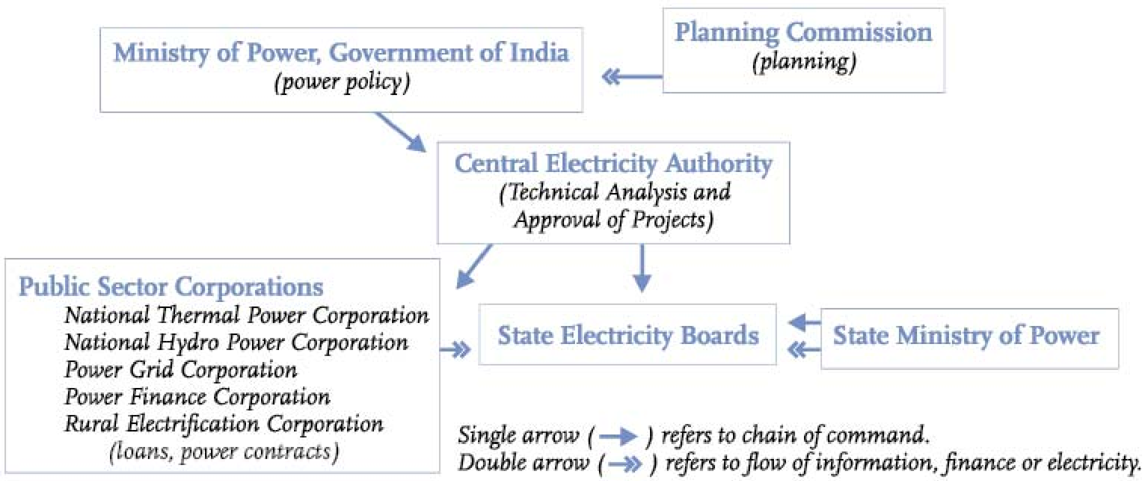


Figure 4: India power sector organizational set-up (pre-1991)
Source: (Dubash 2002)

The Reforms

Knowledge about many of the difficulties facing the power sector is widespread (and people face power blackouts and brownouts regularly). Numerous workshops, conferences, and meetings are held on the power sector and its improvement and reform, with participation by government, academics, NGOs, and industry bodies like FICCI (Federation of Indian Chambers of Commerce and Industry). There is also an attempt to be more inclusive in terms of policies and reform, with public hearings and web-based dissemination of information.[36] However, while there is an agreement that things can not go on as they have in the past, there is no consensus on exactly what must be done, or how. Opposition to price hikes have met with often violent protest. In Andhra Pradesh, 4 people died in August 2000 in police firing (reportedly defensively) against mobs protesting a substantial increase in the price of residential (domestic) power, an increase based on the state regulatory commission (APERC) guidelines.[37] A progressive (tiered) tariff was announced where consumption under 50 kWh per two months would be

[36] Of course, web dissemination is seen as an end in itself, not a means. The author has attempted to electronically comment on some half dozen draft policies, and not received any response through the web.
[37] Of course, many protests in India are political, not grass-roots. The opposition party in one state might publicly oppose policies that it follows in another state where it is in power; this is especially the case with power sector reform. However, after the 2001 Chief Ministers conference, there was a consensus to depoliticize power sector reform.

charged Rs. 1.45 paise per kWh, compared to 80 paise before the hike announced earlier in 2000. Higher users would pay even more, with larger increases, and the biggest users would pay over Rs 7/kWh (from 3.4 earlier)![38] Thus, we can see why there is apprehension over reform, where the results have sometimes been overnight increases of 50-120% in tariffs. Nonetheless, the government of Andhra Pradesh has vowed to continue reforms.

Issues of competition (and disinvestment corruption) lie at many of the concerns over privatization. There are many sectors, such as telecom, oil, and, power, that are prone to monopolistic or oligopolistic rent-extraction. The claim of no barriers to entry does not really apply, even after new rules come in place, because of the large investments required. Past experience of concern to many has included disinvestment where the partial transfer of IPCL (major oil company) was done to private companies for an amount less than its free reserves (cash in the bank) (Bhushan 2002).

Because of political opposition to many reform processes, and legal challenges to such moves through Public Interest Litigations (PILs), the government has slowed down its thrust for reforms. There is evidence that upcoming elections slow down privatization, lest this becomes a plank for the opposition. "The next wave of reforms will only happen when it is proved that not reforming would be far more disastrous than reforming," comments CRISIL's Subir Gokarn (Gupta 2002). Largely because of this slowdown for disinvestments and reforms (poor public sector finances), and deteriorating budget balances, S&P downgraded India's credit rating to junk status in September 2002.

Regulatory bodies are somewhat new to India, and the results have been mixed. In the Telecom Sector, the Telecom Regulatory Authority of India (TRAI) was instituted in 1997. However, due to political wrangling (including disputes with government PSUs) and ongoing controversy over rulings, TRAI was disbanded (quite suddenly) in early 2000. Upon reconstitution (with an Amendment Act), the regulatory and recommendatory functions were separated, and a separate body was created for dispute resolution, stripping TRAI of its quasi-judicial powers. In the power sector, the

[38] It is important to recognize that while many progressive (tiered) systems have social equity advantages, in terms of electricity, such pricing is against microeconomic efficiency, since it costs the most to serve the lowest (or farthest) consumers.

regulators have been given more of a free hand, and appear to be functioning well. We examine the regulatory commissions in detail later in the chapter.

In India, regulatory bodies have been associated with reforms, as before such liberalization, the predominant players were government departments or public sector units (PSUs). Previously, while the CEA (for the power sector) or other statutory body did enforce rules on government entities, control over government entities came through bureaucratic/political channels and dealings made elsewhere, as well. One issue that has not been studied much is the relationship between *laws* and *regulations*. Previously, in the absence of regulatory bodies, the legislature would draft even some of the operating provisions, while other responsibilities would lie with statutory bodies. Now, with regulators in place, Acts state that a regulator/committee/tribunal/etc. would be instituted to perform certain functions. Nonetheless, compared to other countries, it appears that some Indian laws are more detailed and pre-determined, leaving less leeway to the regulators to find mechanisms for reaching socially optimum solutions.

Pre-cursor to reforms

In addition to the underlying financial rot and poor services, there were several trends and policies that let to the current situation, and paved the way for reforms. In addition to the rise of Central PSUs, the authority of the CEA rose, especially over the generating sector. In 1990, the K P Rao Committee advocated a number of steps to increase generation capacity, especially by new tariff setting formulations. They did not advocate competition in the system per se, but did say that generators, mainly the central PSUs, should see fair returns in investments. This became the Reserve Bank of India (Central Bank) rates plus X. RBI + X started as a 3% premium, but moved to 5%. As the RBI rate was roughly 11%, this led to choosing 16% as the return allowed to investors, return on equity. The Committee also advocated a two-part tariff, whereby fixed costs would be separated from variable costs, and recoverable with a certain level of operation (62.8% up to 1992, and 68.5% from then onwards). The Committee also advocated "deemed generation" for the cases when the plant was asked to back down, ensuring they would attain their returns when PLF was lower through no fault of their own. This led to what can be considered performance-based ratemaking (with specified heat rates, oil consumption, etc.), sitting on top of a costs-plus model. Unfortunately, India's use of performance based measures has been very static, often with outdated norms (compared to world wide numbers or even Indian best practices). While a useful step in bringing up laggard power plants, these didn't create the right incentives to innovate or perform better.

1991 Reforms

The 1991 reforms can best be characterized as opening up India's power sector to the private sector for generation. It was also aimed at increasing FDI into India, and showing the world that India was serious about moving ahead with economic reforms and development. The Electricity Laws (Amendment) Act, 1991, was the first major change in law, and provided for generators to operate on a costs-plus model, "regulated" through the CEA, in charge of techno-economic clearance throughout and tariff-setting for some of the PPAs. A Government of India Resolution in October 1991, one month later, opened up "electricity generation, supply and distribution" to the private sector (D'Sa 2002). However, there was very little activity in private distribution and supply, largely due to structural difficulties.

The contextual factors for the reforms included: 1) The poor finances and service of the SEBs, 2) the inability of states to help the SEBs because of their own declining fiscal situation, and 3) a general move at the central level for economic liberalization and reform. There were no significant triggers from the electricity sector, but the Balance of Payments crisis was the trigger for liberalization and fiscal reforms.[39] It is widely accepted that fiscal reasons trumped operational as a reason for pushing ahead with reforms in the power sector.

In addition, there were several other contextual/facilitating factors. Worldwide, there was an interest in IPP development, especially in the growing Asian market. Enron, now disgraced for its finances, was a particular proponent of such deregulation and power

[39] For a detailed analysis of what caused India's 1991 Fiscal crisis, see Cerra, V. and S. C. Saxena (2002). "What Caused the 1991 Currency Crisis in India?" <u>IMF Staff Papers</u> **49**(3).

markets, in the US as well as worldwide. These were also buttressed by the role of consultants, who were often in the picture in terms of Indian reforms.

The norms were based on the prevailing tariff mechanisms, and were reasonably attractive. These were the two-part tariff as per the KP Rao committee, and were generous in terms of both fixed as well as variable costs. The variable costs were all pass through, such as fuel costs, O&M, etc. The guidelines have been termed performance-based, in that the generator has to perform at certain levels to make their money. In actuality, the norms were quite easy to beat,[40] diminishing any tariff reduction that performance based ratemaking was supposed to induce. The fixed costs were to be recovered at 68.5% PLF of deemed generation, giving a 16% return on equity (post-tax). If the equity were in dollars, the returns were also to be in dollars, fully repatriable, and a 4:1 debt equity limit was allowed. The capital costs were also "pass-through," including interest during construction. This led to possibilities of gold-plating (Tongia and Banerjee 1998). Foreign participation was welcomed for promoters to Build, Own, and Operate (BOO) plants, especially large (showcase) plants.

There were also 8 projects chosen as Fast Track projects, ones that were singled out for central government counter-guarantee, to help assuage the investors in case the SEBs were unable to pay. Some of these were with foreign participants, meant to be examples of FDI success. Enron and Cogentrix were some of the big-name projects. These projects were not necessarily subject to CEA approval (CEA claimed it didn't have purview over the Enron PPA), but some projects did go through CEA. They also went through most of the other regulatory clearances, including environmental, foreign investment promotion board, etc., a process many IPP promoters found tedious. Nonetheless, there was pressure to see these projects through, not only to increase generation capacity but to show how "India means business." Very little power capacity came on-line from these fast track projects. GVK Industries' 235 MW gas based Jegurupadu project and Spectrum Power's 208 MW gas-based Kakinada Project have been commissioned (July 1996 and January 1998, respectively, both in Andhra Pradesh), as has the first phase of Enron's Dabhol project in Maharashtra state (740 MW). GVK

[40] Enron was able to stipulate to its equipment suppliers contractually that they surpass the PPA norms.

was the first project to come online, and discussions with officials have led to insights on the process.

Many of these fast track projects became mired in controversy. Some newspaper reports stated that many of the projects were, in fact, NTPC-designated originally, and were “handed over” to the IPPs. NTPC, which had received the bulk of the World Bank funding in the 1980s and 1990s, was given secondary treatment in terms of funding (which led to its strengthening its operations and performance further) as well as the incentives it could enjoy vis-à-vis IPPs (Dubash and Rajan 2001).

Cogentrix, the largest promoter in Mangalore Power Company, in Karnataka, wrangled for years seeking financial closure, while being bogged down with opposition and facing Public Interest Litigations (on environmental grounds). Ultimately, the promoters walked out of the project. However, by that time, few people were lamenting the loss of IPP projects, as this was after the Enron episode.

Enron (see box for more information) epitomized what was seen as wrong with the IPP policy, and fast track projects in particular. These were based on secret PPAs, arrived without competitive bidding, and burdened the SEB with take-or-pay clauses for high offtakes (PLFs). The negotiated rates were quite high, and, to the extent examined, the finances allowed for high returns on paper.

Other than the “fast” track projects (emphasis intentional), other IPP projects have resulted in more hot air than power. While there were hundreds of Letters of Intent or even Memoranda of Understanding signed in the early to mid 1990s, most did not come to any serious conclusion. One trend was for these projects to be set up by subsidiary or Joint Venture companies, such that there is only non-recourse project financing, which is typical of energy projects in developing countries (Razavi 1996). Many foreign investors were interested in the sector, but most wanted Indian partners, to help them navigate the Indian “system.” According the one SEB official, this practice was the source of some of the problems, with non-professional parties joining forces with genuinely interested parties. By August 1995, 189 projects for 75,000 MW were under consideration (D'Sa 2002), based on MoUs or Letters of Intent, but the next stages of approval (CEA techno-economic clearance, Ministry of Environment and Forests clearance, Foreign Investment

Promotion Board clearance, Fuel Supply Linkage, Lending, and then Financial Closure) were cleared by only by a handful of projects. During the second half the 1990s, public sector growth in capacity was actually more than double that of the private sector.

Timeline of the Enron Episode (Enron Action Group 2001; Rediff.com 2001)*:

- **May-June, 1992:** India invites Enron Corp to explore the possibility of building a large power plant in Maharashtra, after earlier discussions in the US.
- **June 20, 1992:** Initial memorandum of understanding signed between Enron and Maharashtra government (in India) for a plant with capacity of 2,000-2,400 MW. The Maharashtra State Electricity Board (MSEB) is expected to pick up a 10 per cent stake.
- **Jan 2, 1993:** The Foreign Investment Promotion Board clears proposal for a 1,920 MW plant, expandable to 2,550 MW.
- **Dec 8, 1993:** The power purchase agreement signed between Dabhol Power Company and MSEB for a 2,015 MW project to be implemented in two phases. Only the first phase is binding.
- **March-June, 1995:** Following state elections, a new Maharashtra government, headed by the Shiv Sena, scraps the project, alleging corruption and high costs.
- **Aug 1995:** Maharashtra Cabinet Subcommittee (Munde Subcommittee) recommends scrapping the project.
- **Aug 1995:** Maharashtra files suit against DPC and MSEB in the Bombay High Court seeking cancellation of the PPA on grounds of fraud, corruption and misrepresentation.
- **Nov 7, 1995:** Rebecca Mark, Enron CEO, misses a scheduled appointment with Maharashtra Chief Minister to meet Bal Thakeray (leading non-elected political figure, who controls the Shiv Sena party).
- **Nov 8, 1995:** Maharashtra Government announces renegotiations
- **Nov 19, 1995:** Project re-negotiated with a final capacity of 2,184 MW. MSEB's stake is upped to 30 per cent -- 15 per cent in the first phase, and a further 15 per cent upon completion of the project.
- **May 1996:** India extends counter-guarantee to the project, under which the federal government promises to cover any defaults by the state utility.
- **Aug 1996:** Legally binding PPA signed, which includes obligations for phase 2.
- **May 1999:** Phase one of the project with a capacity of 740 MW begins operating.
- **June-Oct 2000:** Maharashtra government allies demand scrapping the project because of the cost of the power it produces (Rs 7.81/kWh – based on part load below contracted PLF; even full load would be approximately Rs 5/kWh).
- **Oct 2000:** MSEB defaults on its October payment to DPC.
- **Dec 2000:** Maharashtra state announces plan to review the project, stating that the tariff is too high.

* Plus other sources

- **Jan 2001:** Enron invokes the Maharashtra government counter-guarantee after MSEB defaults on both November and December payments.
- **Feb 2001:** The Credit Rating Information Services of India Ltd cuts ratings on bonds issued by Maharashtra government due to defaults on payments owed to Dabhol. Enron invokes the Union government guarantee.
- **April 2001:** Godbole Committee Report suggests renegotiating the PPA, using judicial review if appropriate.
- **April 2001:** Enron issues a notice of arbitration to the Indian government to collect on the December bill of Rs 1.02 billion.
- **April 2001:** Enron invokes political *force majeure* clause in its contract with MSEB, stating that unfavourable political conditions have prevented it from fulfilling contractual obligations.
- **April 23, 2001:** DPC and its lenders meet in London to discuss the payments issue. Enron seeks lenders' permission to issue a notice of termination.
- **April 25, 2001:** The board of Dabhol Power Company authorizes management to terminate the contract any time it chooses.

Stakeholders are currently seeking buyers to take over the project.

The project was grand, if not "audacious," representing the single largest FDI into India (and also the largest gas based plant in the world, over 2,000 MW in size). The Foreign Investment Promotion Board was the body that suggested splitting up the project in to two phases (Choukroun 2001), and the project proceeded with this goal. In the meantime, with opposition within the Maharashtra government, they sought the opinion of the World Bank on the project. The World Bank issued a confidential report against the project, and in an April 30, 1993 letter[41] to the Finance Secretary, stated the project "is not economically viable, and thus could not be financed by the Bank" (Choukroun 2001). Reservations were focused on the very high PLF (90%) being contracted, the size of the plant, a capacity that could not be absorbed by the system with least cost dispatch, and the very high costs, benchmarked in US dollars at that. CEA issued only provisional clearance in November 1993, but Enron proceeded with the PPA for a 20 year contract based on this.

After the 1995 elections, the new Shiv Sena government filed suit against Dabhol Power Company and MSEB seeking to cancel the PPA on grounds of corruption and fraud. But, they then renegotiated the contract, based on an 11-day review by a

[41] Details available at http://www.altindia.net/enron/, an anti-Enron Dabhol site.

committee headed by economist Kirit Parikh. Parikh had earlier expressed reservations against the deal, but supported the project in a modified form (including price reductions and change in fuels). This renegotiated contract cut the price to Rs.1.86 per kWh from Rs.1.89 per kWh before, but the second phase was made binding.[42] There continued to be pressure to push along with Dabhol, with the central Power Minister Salve stating that stopping progress on Dabhol would be tantamount to an "anti-national act. Contracts have been signed and the price of canceling will be very high" (Choukroun 2001).

Enron represented a mini-litmus test for US-India relations. During its inception, there was optimism and signs of growing relationship. Then, as the incident turned into controversy, there were very high-level statements that India should respect the "sanctity of contracts," or risk losing all foreign investment. The U.S. Energy Secretary in June 1995 publicly warned: "Failure to honor the agreements between the project partners and the various Indian governments will jeopardize not only the Dabhol project but also most, if not all, of the other private power projects proposed for international financing" (Bidwai 2002).

The political importance of this project and possibly why this took off at all was shown by several things (Bidwai 2002): 1) A 1995 meeting between Maharashtra political supremo Bal Thackeray and Enron Chief Executive Rebecca Mark, 2) Enron's admittance to an expenditure of $20 million for "educating" Indians about the project, 3) rapid clearance to the project by then Finance Secretary Montek Singh Ahluwalia, and 4) a sovereign counter-guarantee issued by the 13-day Vajpayee government in 1996 – this being the only executive decision taken by (that) Cabinet, during a five-minute meeting on May 27, 1996, at the end of their term. Other critiques of the deal can be found in the works of Sant et al. (1995) and Mehta (2000).

People have questioned whether the government had the legal right to issue sovereign counter-guarantees for the Fast Track projects. Articles 292 and 293 of the constitution limit such actions by the executive branch (Mehta 2000), and certainly no statutory body has such powers. When people posit whether the Enron deal was corrupt,

[42] These prices are based on a number of optimistic fuel and foreign exchange assumptions, which turned out to be off the mark. They were also based on full, contracted load.

the bottom line remains if it was not corruption then it was *ineptitude*[43] that allowed it to come to being. The end result was the same, very expensive power that the state didn't want (at the contracted PLFs), and a bad name for the reforms process and foreign investment in the sector.

GVK Industries' Jegurupadu Gas IPP – First fast track project to commence operations

While there are numerous studies on the Enron project such as by Parikh (1996), GVK's 235 MW Jegurupadu project is considered a IPP success, and was the first IPP to come online after the reforms. One *main reason this project came on stream so quickly was because of the absorption of risk* by the project promoters. GVK began construction (civil work) even before a PPA was signed, and undertook a loan from IDFC for this. Even the turbine vendor (ABB) delivered the turbine before financial closure. In fact, the first turbine was commissioned before the final PPA was signed. This is unusual, in that most project promoters try to mitigate all the risks they can through contracts before putting up their money. But, such moves delay projects significantly, often raising the costs and leaving time for opposition to the project to build up.

This project was actually envisioned as an Andhra Pradesh SEB (APSEB) project, based on the recent gas finds. APSEB had already sited the land for the project, and 1.5 million cubic feet per day of gas was allocated (enough for 400 MW). Then, there was a shift in policies, and IPPs were encouraged. During a visit to the US by the Chief Minister in 1992, he met with a Non-Resident India (NRI), G. V. Krishnareddy (GVK), who was encouraged to set up such a plant. GVK had almost no power sector experience at that point, but was a successful industrialist. An MoU was signed in 1992 for such a project. However, half the gas was given to NTPC, and the plant size was reduced to 235 MW.

While an initial PPA was signed with CEA in December 1994 (and was based on a draft by APSEB Finance Member!), it had to go back to CEA after GVK requested counter-guarantees, after Enron received the same. (The counter-guarantee was only for the foreign investment portion.) This was one of the reasons that there were delays in the PPA compared to proceeding with the construction. Financial closure was not reached until March 1997.

ABB actually took a 5% stake in the company (a special purpose vehicle set up for the project) at the time of the order, and CMS Energy (USA) took 18% (CMS were also partners for O&M). The fact that GVK was an NRI was useful for IFC support for the foreign exchange

[43] Observers note that a few initial bad deals are part of the learning process. If the PPAs were not kept secret, enough skills existed in India to question at least several of the PPA tenets.

component of the project. All of these helped push the project along, despite delays in clearances. GVK Industries said a total of 166 clearances were required, and this took significant effort, making the power offtake agreement, fuel supply, and lenders contracts seem less onerous!

It had first year costs close to Rs. 2.1/kWh, but the levelized cost is pegged at Rs 1.82/kWh. This plant, in Andhra Pradesh, operates on natural gas, a fuel that is not available in most of the country today. Having gas available at Rs. 3,900 per thousand cubic meters (or just under $2.3/MMBtu) is one reason for its low cost of power, with only 86 ps/kWh as the variable costs.

Some insights that GVK provided included information on equipment cost differentials. Most IPPs prefer foreign vendors for equipment, despite their charging 10-15% more in India than elsewhere. While BHEL is available domestically, they are not cheaper, and they do not offer supplier credit, unlike many global vendors. When factoring in import duties (20%), we can see that capital costs in India do not match international numbers. Vendors might be charging higher because of added costs of doing business (risks), but it might be a non-competitive market, as well.

Operationally, the plant runs at an average PLF close to 85%, despite the contract being for 68.5%. (Such a move gives them – or any generator – significant extra returns.) When questioned about the cost of power in the state, officials from GVK pointed out the losses and low efficiency are to blame, such as the extra high voltage losses alone being some 5-8%. Labor is also mentioned; GVK has about 50 personnel for its plant (excluding security), while a comparable plant within APGenCo has 250.

Like all IPPs, this project is not without its critics, especially over its PPA. Based on the Controller Auditor General's 1998 Report, in place of the 400 MW plant originally estimated to cost Rs. 518.20 crore, the plant built was 235 MW but at a cost of Rs. 816 crore (Reddy 2000). However, it must be mentioned that 1991 saw a sharp devaluation of the rupee, possibly accounting for much of the difference. Comparisons in US$ would likely have not produced nearly as dramatic a difference. Nonetheless, critics of IPPs maintain that capital costs are high when compared to similar projects in developing countries, especially for CCGT plants, which are meant to be cheap to build.

1998 (and Earlier Orissa) Reforms

There was no closing point or declaration of a failure of the 1991 reforms. Rather, there came the understanding that without structural changes into the system, investment into generation selling to the bankrupt SEBs would be minimal.

While The Electricity Regulatory Commissions Act came about in 1998, much work was already underway towards such reforms. Notably, Orissa was already undertaking restructuring reforms (and Haryana, also under World Bank guidance), with Orissa the front-runner by 3 years. In looking for methods and forms of reforms, there were several factors which led to an approach similar to a regulatory model of the US instead of the UK (Sankar and Ramachandra 2000). These included: 1) the need for a new, independent quasi-judicial regulator, 2) the need for introducing transparency in the reform process, including through public hearings, and 3) a basis for costs-plus tariff-setting similar to that already existing. There was also considerable support given by US groups including regulators (Federal Energy Regulatory Commission as well as State-level regulators) for reforming India's power sector. Some of this was likely driven by the push from US industry and government, who were eyeing India's large power sector as a market for investment and sales.

One of the influencing works was a report prepared in mid-1996 for USAID by several consultants from Hagler Bailly, "The role of planning in India's restructured power sector"[44] (D'Sa 2002). This report the report determined three critical elements:

> *Independent organizations*: These would be either new or reorganized entities operating the system, as well as newly-constituted regulatory bodies.
>
> *Unbundled functions*: The previously vertically integrated utilities broken into generation, transmission and distribution entities.
>
> *Private ownership*: Privately owned utilities (commercially-driven) would provide much of the growth of the sector.

By this time, it was clear that adoption of such views would become necessary for availing of multilateral agency funding (World Bank 1993).

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[44] Borgstorm, B., Hindley, P., & Gupta, P. (1996). *The role of planning in India's restructured power sector*.

Late 1996 saw the adoption of a "Common Minimum Action Plan for Power" at the Chief Ministers Conference. This action plan laid the foundation for reforms in the country, and included finalizing a National Energy Policy, amending the laws to set up Regulatory Commissions, rationalizing tariffs, streamlining approvals for projects, increasing autonomy and improving management of the SEBs, and bringing in the private sector into distribution (D'Sa 2002). The steps leading up to the Act are important, showing how political recognition of the problem and possible solutions was greater than the steps that actually made it in law. The Electricity Regulatory Commissions Ordnance was passed in April 1998, legalizing two main features of the Common Minimum Action Plan, viz., establishment of the Regulatory Commissions and rationalization of consumer tariffs. Within 3 years after commence of the ordnance, it stated that no class of consumers should be charged less than 50% of the average cost of supply of electricity. However, due to realpolitik and lobbying, this provision was removed from the final Act in Parliament in July 1998 (D'Sa 2002).

The CERC, established in August 1998, has been working on policies of central and inter-state concern such as a National Electricity Grid Code and an Availability Based Tariff Regime, while the State ERCs have been dealing with the state-level agenda.

Regulatory Commissions

One main feature of the 1998 central (and other state-level) reforms has been the establishment of independent Electricity Regulatory Commissions. Their jurisdiction has been based on geography and boundaries, in that entities crossing state borders and for central bodies (PSUs), CERC has jurisdiction, else it lies with the respective State ERC. Their broad mandate is for decision-making and tariff-setting for all aspects related to the power sector. The ERCs were constituted under legislation, either by the respective states on their own, or through the 1998 Electricity Regulatory Commissions Act (see Table 15 on page 90).

Beyond simply regulating the various players in the sector as per existing norms and guidelines, an important feature of the regulatory commissions includes their focus on tariff rationalization (enshrined in the Acts), and their attempts to disclose their tariff philosophy. However, while they often focus on the "competitiveness" of the industry, there is only limited push for introducing *competition* in the industry (Ahluwalia and Bhatiani 2000).

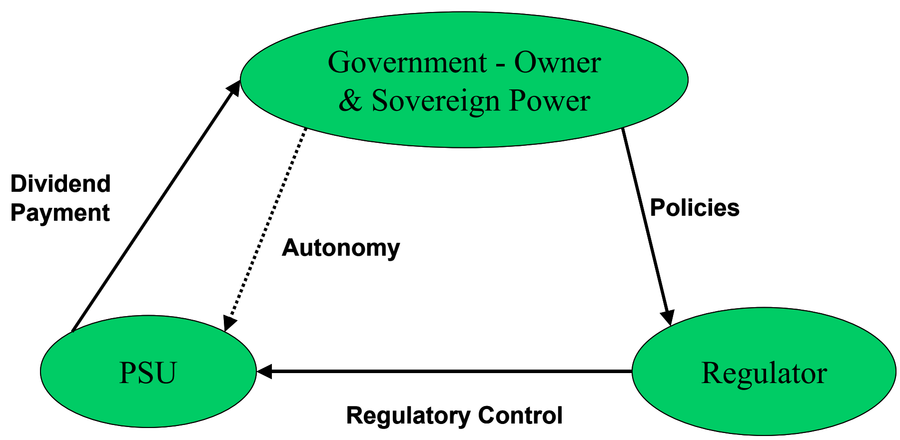

Figure 5: Relationship between government, regulator and PSUs
Source: CERC

Important questions relating to the regulatory commissions are:

1. <u>Are they independent?</u>

   Every effort is made to ensure their independence, in that Members have reasonable job security and a mandate spelling out that their job is to look out for the public interest. This is evidenced by the number of times government utilities and PSUs have clashed with ERCs over their orders. In fact, there is the feeling that different groups (Central PSUs) have been treated differently than IPPs. Recently, CERC announced new guidelines that would reduce the charges that NTPC could pass through for O&M and depreciation (to the extent that NTPC's growth projections have been cut in half).[45] NTPC's allowed return has also been reduced.

[45] "CERC, in its Order dated 04.01.2000 on ABT, had fixed target availability of 80% w.e.f. 01.04.2000 and 85% from 01.04.2001 against 70% agreed in the NTF (National Task Force). NTPC had filed Review Petition against this Order of the Commission on which CERC issued its Order on 15.12.2000 fixing the target availability of 80%. Subsequently, vide its Order dated 21.12.2000, CERC also issued tariff norms in which rates of depreciation were reduced from 7.84% to 3.6% and O&M escalation was limited to 6%

However, when concerning regulation versus policy, "…both central and state commissions have to be guided by government directives (central and state) in matters of policy involving public interest. If there is any dispute on whether a directive relates to a matter of public interest, the legislation is clear about the decisions of governments being final" (Sankar and Ramachandra 2000).

The ERC budgets are to be funded through provisions made in the consolidated fund of the respective central or state budget, freeing them from the control of the Ministry of Power. However, they must still go to the government for this amount, and the amounts available are not large, limiting the ability to hire outside analysts. Reality aside, the public perception of their independence is less clear, since most Members have Civil Service (and/or SEB/CEA) backgrounds.

While much has been said about the independence of the Regulatory Commissions, Dixit, Sant et al. (1998) worry about their *accountability*. Given their vast powers and purview, and that their rulings can not be challenged on techno-economic grounds, it is only their good intentions that can help the public at large. There is no direct accountability. In addition, their philosophies are important since policies are given by the government, and they only issue regulations. Are they ultimately looking for the public good, increased profitability, or what combination of such goals?

2. <u>What is their jurisdiction?</u>

There are three distinct roles that electricity regulatory commissions have to play (Sankar and Ramachandra 2000):

- *Core role*: Includes tariff regulation, monitoring quality of service, adjudicating disputes, enforcing licensing conditions, monitoring compliance and redressing grievances.

  Some of the key actions the SERCs have directed utilities to undertake include: putting up metering for all consumers within a specified time frame, measuring technical losses, and reducing commercial losses.

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against prevailing norm of 10%. Implementation of these Orders of CERC will result in reduction in internal resources of NTPC by about Rs. 23,000 crores over the next 11 years and will force NTPC to reduce its 20,000 MW capacity addition programme to only about 8,000 MW in the next 11 years." *Ministry of Power Annual Report 2001-02*.

- *Recommendatory role*: If approval (of licenses, for example) does not come under its jurisdiction, the electricity regulatory commission can give its recommendations to the concerned authorities.
- *Advisory role*: Where it provides to the government, on request, information and advice on matters of importance to the sector.

While ERCs actively participate in many of these roles, and have very broad, sweeping powers, there are a few limits on their powers. For starters, they have indicated they will not question PPAs (with IPPs or others) that were drawn up before their formation (grandfathering actions that would now not pass muster). (However, Section 23 of the Indian Contracts Act 1872 (still in force!), allows the government to annul all contracts that violate "morality or public policy" (Bidwai 2002)). Secondly, while central-state ERC disputes are limited, there are implications for generators. CERC rarely regulates IPPs, who must deal with SERCs. NTPC, like other Central PSUs, is subject to CERC guidelines. In such cases, if there is a difference in policies or norms, there can be unequal effects. NTPC has complained that it enjoys lower returns and allowed expenses than many IPPs because of this (Mahalingam 2001). There are also issues over conflicting jurisdiction and roles with CEA, which was earlier in charge of many of CERC's functions. CEA has seen a decrease in its importance, especially relating to tariffs, and there is some duplication in terms of some statutory roles (Dhall, Mirajkar et al. 2001). The diminishing of CEA, which is likely to be recast into a more technical role only, will continue with the Electricity Bill 2001 (in parliament), which removes the need for techno-economic clearance by CEA for new generators. Nonetheless, the ERCs have wide powers over the regulation of the power sector in India. In fact, many utilities do not appreciate the scope and extent of their powers until they face a notification or resolution.

The limits on ERCs extend to several gaps in terms of functions. Normally, a electricity regulator would enforce dispatch rules. As generation is at a grid level (eventually, national, but regional today), a national level body (i.e., CERC) should be responsible for enforcing such actions by the appropriate operating body (a role PowerGrid is reported to be eyeing, but functionally falls to the RLDCs). However, today, dispatch, especially in terms of financial implications (relating to PLFs and contracts) is handled at a state level. The Regional Load Dispatch Centers do not appear to be under direct control of the ERCs, thought the recent Electricity Grid Code attempts to rectify this (PowerGrid 2002). But, this document only applies to generating stations and utilities dealing across state borders, leaving in-state to other entities. This could have negative operational impacts in terms of grid stability and finances (especially finding merit order dispatch).

3. <u>How can they enforce their orders? What happens when rulings are challenged?</u>

The ERCs are statutory, quasi-judicial bodies (with the powers of a Civil Court), and appeals are taken in the High Court. The basis for their orders comes from legislation, but this is a weak link in their powers. Disobeying their directives has unequal effects for government bodies versus private operators. If a loss-making government utility ignores a certain calculation (e.g., allowable losses), it only affects their paper losses. In theory, ERCs can impose strict fines, or even have offending personnel jailed. If groups question ERC findings/rulings, they, today, first appeal to the ERC, and if they question the ERC itself, would take the matter up with the judiciary. The first challenge to rulings is usually this, especially questioning the authority or jurisdiction of the ERC. This was most notably the case in Karnataka, where the state utility took the KERC Tariff Order to court, claiming the regulatory authority had no jurisdiction to pass specific directives regarding its operations. The court passed an *ex-parte* stay order, and KERC had to file an appeal in the Karnataka High Court against the stay order (Sankar and Ramachandra 2000). However, most of the time, courts do not issue stay orders against the ERCs, finding them to be fulfilling their obligations as per the law. Even when stays are issued, higher courts usually vacate such stays. This was the case for the Supreme Court weighing in favor of CERC against NTPC (Infraline 2002). Nonetheless, court activity consumes a significant portion of ERC staff time, even against government entities that often view the courts as a useful delay tactic against the inevitable.

SERCs, like the courts, are probably unprepared to handle the volume of cases that would arise from redressal of individual consumer grievances. It has been suggested that a tribunal or similar body be constituted for such matters. How does an affected party question ERC rulings? The main mechanism is through appeals and reviews (by them). The link to policy changes versus ERC regulations is hazy, as the ERCs directives are largely questioned in terms of technicalities and jurisdiction, not overall policy and philosophy. There is uncertainty how much leeway ERCs will (or should) continue to have. A case in point is the treatment of wheeling of third-party sales (captive power). Different SERCs have ruled differently on this, but a coherent, national strategy would be more appropriate (something the 2001 Electricity Bill is supposed to address).

In terms of the Judiciary in India, this is viewed favorably as being quite impartial and independent. However, it is overstretched, with an average backlog in the courts measured in years. The judiciary does not see major jurisdictional conflict with most regulatory commissions (not just power sector), with appellate tribunals often staffed with retired Judiciary members. It is worth mentioning that the Judiciary in India is considered activist, especially when it comes to environmental and consumer matters. Examples of their rulings included the introduction of lead-free gasoline and the mandated use of CNG (compressed natural gas) for public transport vehicles in Delhi. The rule of law is honored, and most contracts are honored (critics wonder if better negotiation skills would help before and even *after* the contracts are signed). Putting aside the contractual disputes that came later, Enron was pleased with the Indian judiciary when they won all the court cases against their Dabhol project during the construction phase.

4. <u>How are they constituted? What are Member qualifications? Staffing/resources?</u>

When looking at the build-up of the regulatory commissions, these are governmentally appointed entities of 3 members, except the CERC, which has an additional Chairman-Member and ex-officio member (Chairman of CEA). There is a government search committee established as per the laws to find the members.

Salient features of the memberships are as follows (generalized):

Term: The members shall hold their post as Member or Chairman for 5 years or until the age of 65, till whichever comes earlier. Members/Chairman must be at least 55 years of age. The initial members will have a 3, 4, and 5 year term to prevent simultaneous vacancies and turnover. They can not be removed from office except in exceptional circumstances, with proceedings equivalent to impeachment. However, they are only eligible for a single 5-year term.

Qualifications: All members are expected to be eminent in their fields, with an emphasis on electrical engineering, law, policy, accounting, etc. At least one member must be a technical person, and the other two must have different expertise.

Other conditions: The Commission shall remain impartial, and no member should have a conflict of interest through ownership, representation, business activities, etc., with companies or entities subject to relationship. They must also not hold appointed or political office.

In terms of size and scope, a three person Commission, if appropriately qualified, should be a reasonable size to perform its functions well. In the United States, the different state Commissions have between 3 and 5 members (but these also oversee other utility functions, like telecom, and sometimes public transport). What is different is that in the US, the appointment and/or role of the Members can vary from directly elected to appointed, from fixed term non-removable to removable (but usually with renewal possibilities).

A bigger issue, especially given the age requirements, is that joining the ERCs is seen as a career-climax job, often held by retiring government employees (CEA, SEB, or Civil Services). These are, often, seen as a cushy post-retirement job for bureaucrats (Sankar and Ramachandra 2000). Comments by insiders indicate that Delhi's ERC lacks personnel (with just one founding Member, or Commissioner, who was a power sector professional) precisely for this reason, in that no one wants to join and be under the Chairman who is considered to have a "junior" background vis-à-vis many IAS[46] officers. This also means that typical Commission Members have a government and/or utility background, limiting new ideas, innovation, and the ability to effect major (disruptive) change. For example, some regulators questioned utilities for their failure to meet the obligation of 3% Return on Assets. However, almost none of them questioned the 3% metric itself, or what components it should or shouldn't include. Similarly, while

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[46] Indian Administrative Services – India's elite Civil Services, modeled on the British system (bureaucracy with life-long job security – but officers are often transferred to different departments within the government).

many SERCs have questioned utilities over their claims for technical versus commercial losses (and accounting problems), none have really looked into the technological reasons for the higher transmission losses, not using common tools like benefit cost analysis.

In terms of staffing, most SERCs and the CERC are understaffed (Orissa and Andhra Pradesh are reportedly exceptions), especially when it comes to specialist personnel. If one examines the make-up of the CERC, we see that significant numbers of senior staff positions are vacant.

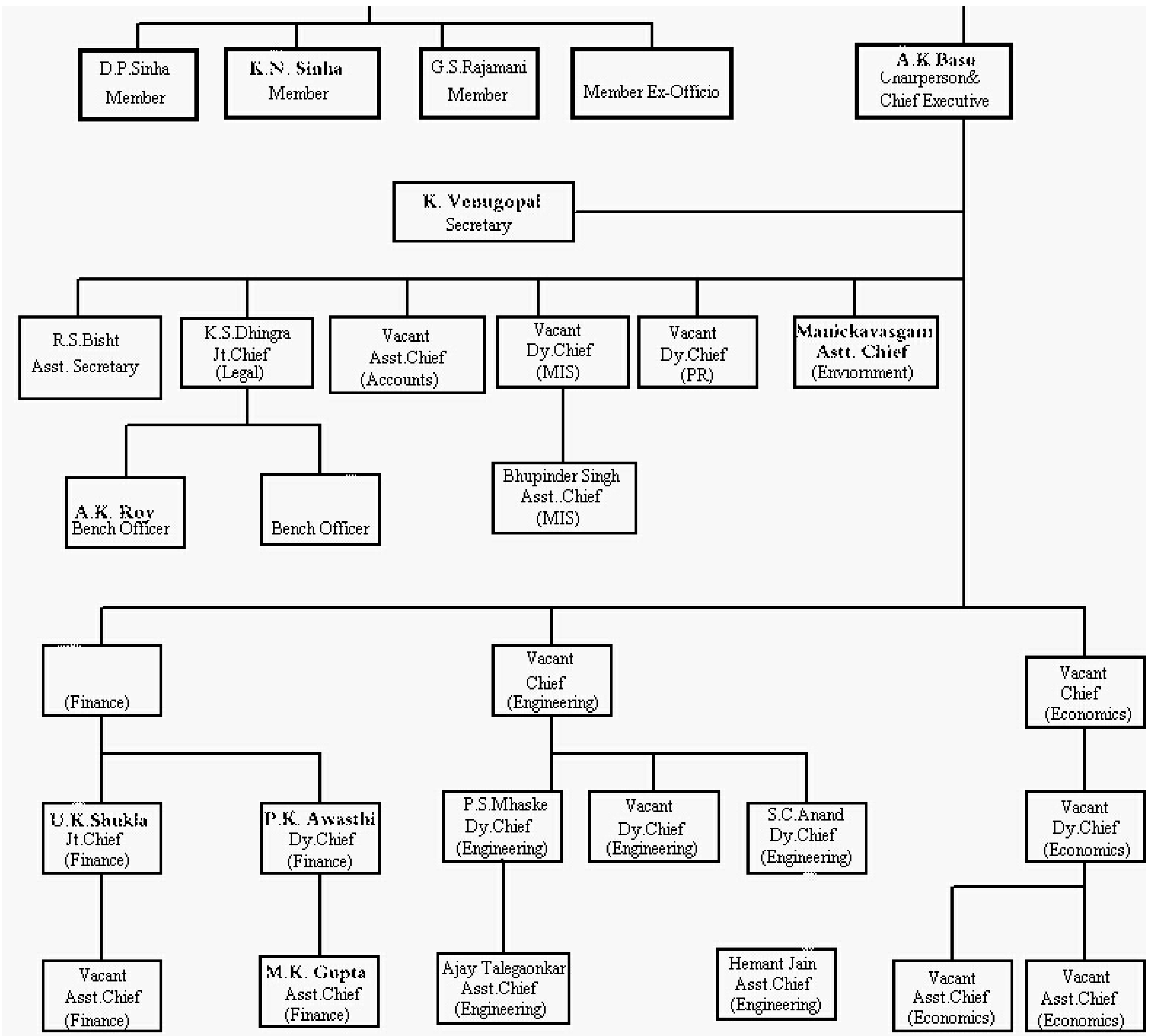

Figure 6: CERC Structure and Vacancies
Source: http://www.cercind.org/org.htm, accessed January 15, 2003.

The CERC website no longer lists Mr. D. P. Sinha as a Member of the Commission, but lists Mr. H. L. Bajaj, Chairman of the Central Electricity Authority, as the Ex-Officio Member. While the listing of vacancies might not be instantaneously accurate, it is indicative of the general situation. The lack of staff extends to the highest level. In fact, since the retirement of the first Chairman, economist Dr. S. L. Rao in January 2001, there was no Chairman until April 2002, when Mr. Basu assumed the position.

Discussions with CERC staff have also indicated that hiring personnel is often difficult, since many staffers initially came on deputation from other government (power sector) agencies and departments, e.g., earlier staff were often from the CEA. There remains the issue that such moves are seen as either temporary or as a hindrance to the regular career track, especially if the regulator is viewed as confrontational or adversarial to the other entity.[47] While the highest level (Member, or Commissioner) jobs are high ranking, with the Chairman being a secretary-level government appointment, most staff positions find it difficult to attract high-level professionals. This is because the salaries are government scale, but the perks and compensations are often not.

This phenomenon of manpower turnover extends to the Ministry in general. There was often no separate Minister of Power, with the Prime Minister holding this as an additional portfolio (with a Minister of State only). Reforms and directions have often been associated with the Minister in charge. There was the perception of seriousness about power sector reforms with P Kumarmangalam in charge. His untimely death in 2000 resulted in Suresh Prabhu taking charge. He was also viewed quite favorably by industry and observers, with an image of "Mr. Clean." In fact, his focus on improving the power sector was the reason for his downfall, as his party (Shiv Sena) boss Bal Thackeray complained Prabhu was not doing enough for his party and asked him to step down in 2002 to focus on party needs. His replacement, Anant Geete, has been keeping a low profile, but ensures he is committed to continuing the work of his predecessors. In

[47] This has also been the case with other regulatory bodies, including the Atomic Energy Regulatory Board (Arunachalam and Tongia, *India's Nuclear Power Program*, working paper, unpublished). The AERB regulates the nuclear power sector, but reports to the Secretary, Dept. of Atomic Energy (as Chairman, Atomic Energy Commission) itself.

terms of the bureaucracy, looking at the Secretaries of Power since the 1990s, we see the typical tenure has not been for very long[48]:

1990-92	S. Rajgopal	Dept. of Power (before becoming a full-fledged Ministry)
From 7/14/92	R. Vasudevan	
From 7/29/95	P. Abraham	
From June 1997	Dr. E. A. S. Sarma	
From 6/1/00	A. K. Basu	Since moved as Chairman, CERC. He was also on the selection committee for that position.
From 4/13/2002	R. V. Shahi	

The appointment of R. V. Shahi as Secretary, Power, is viewed quite positively, as he is not a bureaucrat but a technocrat, the former Chairman and Managing Director (equivalent to CEO) of BSES, the private utility. This lends support to the view that reforms are well underway, and, perhaps, have reached the point of no return. But, a short tenure at the top might make it difficult for decision-makers to take a long-term view, necessary for improving India's power sector.

While there has been a slowdown in the reforms process overall, largely on political grounds, the power sector continues with reforms, albeit at a slower, steady pace, unlike the generation-centric reforms of the early 1990s. Any negative international experiences with power sector reform (like the California crisis) do not seem to have affected power sector reforms in India significantly.

Newer Reforms – Focus on Distribution

While there is no clear trigger for how the Ministry shifted its focus, due to a groundswell of opinion and views, the Ministry has shifted its focus in the reforms process to the distribution sector. Part of this might come from the realization that simply putting up more generation capacity will not help the sector's viability, while part of it might be simply moving ahead after structural changes (unbundling, regulatory commissions, etc.) were already in place.

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[48] The Indian (British-based) system was supposed to have a near permanent bureaucracy, giving stability as the elected politicians shifted over time. This is in contrast to the American system, where the new executive office brings in a new (but fixed term) operating staff for the various departments.

The best description of the new plans might be to call them a balance of carrots and sticks. Several initiatives are proposed to help states with the reforms process, and those that fail to comply will find it difficult to access central government funding (and perhaps even output from central PSUs). In fact, the central government has offered incentive bonus credit (matching funds) for any savings states see from lowering theft losses, on a recommended basis of one for two (Deepak Parekh Expert Committee on State Specific Reforms 2002). In the midst of these reforms, there has been a thrust on access to electricity, with a policy directive "Mission 2012: Power for All." The mandate is for the village level initially (by 2007), but all households by 2012, relying on upgraded infrastructure and schemes like *Kutir Jyoti* (free subsistence level connections). However, we don't know how such a scheme could be realized, not without further worsening the finances of the utilities or enormous government outlay.

The main tenet of these reforms revolves around the Accelerated Power Development and Reform Program (APDRP)[49], which has a focus on sub-transmission, distribution, and metering. APDRP's aim is to allow a marked performance in these areas, reducing losses and increasing utility control over its power distribution (cutting down theft). Several dozen distribution circles have been targeted as prototypes for development as "models of excellence" and will have (Ministry of Power 2002):

- Full metering, energy audit and MIS, control of theft.
- Increase in transformation capacity.
- Increase in HT/LT ratio. Systems analysis and reconfiguration.
- Reduction of technical losses.
- Timeframes for full conversion during the 10th Plan.

This program will provide significant amounts of funding for these activities, with a Rs. 35 billion provision for 2002-03. 50% would come as a grant and 50% as a Central loan, and financial institutions would provide an additional Rs. 35 billion. The result has been a substantial flurry of activity by utilities (and consultants/contractors eyeing the pie), who see these funds as the means to improving their system. Part of this

[49] This was begun in 2000 as the Accelerated Power Development Program (APDP). APDRP adds a focus on reforms. In addition, the Deepak Parekh Committee (2002) recommended improvements making APDRP more results (output) focused, and less organizationally burdensome in terms of projects.

expenditure will be for the same goals, but to comply with SERC guidelines that had been issued without worrying about how the utilities would fund what they require to do. An example of this is metering rural (agricultural) loads. Thus, APDRP is likely to be a useful mechanism for activities that might not otherwise have been fiscally feasible, but are necessary for the long term viability of the system. One major philosophy for APDRP funding is providing funding to those states who meet pre-determined milestones towards rewards.

Ranking of Reforms Process and State Activities

The new reforms indicate conditional loan forgiveness and credit, something that can allow innovation across states (and will benefit from inter-state competition for funding[50]). The Ministry of Power, through the Power Finance Corporation, has retained ICRA Ltd. (formerly, Investment Information and Credit Rating Agency of India Limited) and CRISIL (Credit Rating Information Services of India Limited) to rate the states' power utilities. This rating is not based on their finances, but their extent of reforms and steps being taken to move towards commercial operation (Table 13). These rankings will be useful for the government when considering financing and assistance to the states for reforms.

The study attempts holistic approach to the rankings, and factors in the study include external and internal ones (ICRA/CRISIL 2003). External factors include the state government, and its commitment to reforms expressed through subsidy payments, tariff reforms, and passing legislation towards the reforms (20%), and the Regulatory Commission (20%), measuring its tariff philosophy, tariff orders, and protection of all-round interests. While external factors are only 40% of the results, they show a high correlation to the overall results, emphasizing the importance of the state commitments and SERCs. Internal factors to the utility include generation-related parameters (6%), transmission and distribution related parameters (19%), financial risk parameters (30%), and Information and MIS assessment (5%). Generation counts for a lower portion of the state rankings, as most of the efforts will be in the distribution sector.

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[50] Critics point out that much assistance has historically been based on political considerations, not any transparent guidelines.

Looking at the results, a few surprising results come to light. While Andhra Pradesh ranks highest, Orissa ranks quite poorly (14th out of 26), with most of its score coming from its ERC. This is possibly an objective indictment of the Orissa reforms, which were first in the country. We also see that there is a fair but not absolute relationship between timing and ranking (with Orissa as the major outlier). Of the major states in India, Bihar ranks second last, an indication of its reform record.

When considering the actions of states, the Ministry of Power has signed Memoranda of Understanding (MoUs) with many states for reforms (22 at last count), especially in distribution but overall as well. These have often been signed as an act of good faith whereby the States pledge to undertake reforms and meet certain guidelines in return for which the Ministry of Power would offer support in terms of either increased output or access to central power stations, financing, upgraded transmission lines to outside the state, etc. Some aspects of the MoUs cover:

- 11 kV metering
- Consumer metering
- Energy audit, effective MIS and control of theft.
- Tariff determination by SERCs
- Timely payment of subsidies

However, very little coordinated action is seen the various states, many of whom promise to undertake similar action steps or experiments, e.g., targeting a few districts for 100% billing and auditing, using IT and electronic metering for controlling losses and theft (as per the IT Task Force 2002), etc. It appears that if new technology or business practices are to be tested, coordinated efforts can result in cost and perhaps time savings. This is particularly the case when considering the need for upgrading distribution networks, or even just installing meters for agricultural consumers, and investment on the order of hundreds of millions (if not billion) of dollars, assuming some 13 million or more unmetered but legal agricultural connections – with a potential of 20 million pumpsets – and a cost of several thousand rupees per meter (excluding sophisticated electronics or communications – simple kWh meters).

Table 13: State Reforms Performance Rating (ICRA/CRISIL). This table shows important states of India and their reform ratings. A score of zero can indicate non-performance.

	Rank		1	2	3	4	5	6	7	8	9	10	11	12	13	14	25
		Max. Score	Andhra Pradesh	Karnataka	Haryana	Rajasthan	Maharashtra	Delhi	Gujarat	Himachal Pradesh	Tamil Nadu	Punjab	Uttar Pradesh	Goa	West Bengal	Orissa	Bihar
I	***External Factors***	***40***	***31.5***	***27.5***	***29***	***26***	***19.5***	***29.5***	***24.1***	***18.3***	***6.5***	***5.5***	***21.8***	***8.8***	***17.3***	***18***	***2.5***
A	**State Govt. related parameters**	*20*	*13.5*	*12.5*	*13*	*10*	*8.5*	*14.5*	*12.6*	*6.8*	*4.5*	*3.5*	*6.8*	*7.8*	*7.3*	*5*	*2.5*
A1	Existence of formal Action Plan for time bound reforms	5	4	4	4	4	3	4	3.1	3.1	1.5	2.5	3	2.8	3.5	2.5	2.5
A2	3 year track record on subsidy payments	5	5	3.5	4.5	1	1	4	5	2.5	0	0	1.3	1.3	0	0	0
A3	Sustainability of subsidy	5	1.5	1.5	1.5	1.5	1.5	3.5	2.5	0	1.5	0	0	2.5	0	0	0
A4	Legislation for power sector reforms	5	3	3.5	3	3.5	3	3	2	1.3	1.5	1	2.5	1.3	3.8	2.5	0
B	**SERC related parameters**	*20*	*18*	*15*	*16*	*16*	*11*	*15*	*11.5*	*11.5*	*2*	*2*	*15*	*1*	*10*	*13*	*0*
B1	Infrastructure	5	5	5	5	5	4	4	4	2	2	2	4	1	4	4	0
B2	Timeliness of orders	5	5	1	2	3	1	4	1.5	2.5	0	0	4	0	1.5	4	0
B3	Tariff philosophy	10	8	9	9	8	6	7	6	7	0	0	7	0	4.5	5	0
II	***Internal Factors***	***60***	***40***	***40.5***	***35***	***38***	***40.5***	***23***	***27.4***	***31.1***	***41***	***39.5***	***21.1***	***32.3***	***18.6***	***15***	***8.7***
C	**Business Risk Analysis**	*25*	*19*	*14*	*13.5*	*14.5*	*15*	*8.5*	*14.1*	*12.5*	*18*	*16*	*8.5*	*14*	*8.6*	*8*	*4*
C1	Generation	6	5	4	3	5.5	5	1.5	3	1	5	5	2.3	0	1.3	1.5	0.3
C2	Transmission and Distribution	19	14	10	10.5	9	10	7	11.1	11.5	13	11	6.3	14	7.4	6.5	3.8

D	**Financial Risk Analysis**	*30*	*17*	*22*	*17*	*19.5*	*22*	*11*	*11.3*	*16.6*	*19.5*	*19.5*	*10.6*	*14.8*	*6.5*	*7*	*3.7*
D1	Gearing Level (Total debt/adjusted NetWorth)	2.5	2	2	0	1	2.5	0	0	1.9	2	0	1.9	1.3	0	0	0
D2	Revenues from sale of power/(Power purchase costs + Own generation costs incl. Fuel and O&M costs)	3.5	2	2	2	2	3.5	0	0	3.5	2	3	1.8	1.8	1.8	2.5	0
D3	Revenue from sale of Power/(All operating costs + Interest costs)	5	3.5	3.5	3.5	3.5	5	4	2.5	3.8	3.5	3.5	3.8	3.8	3.8	3.5	2.5
D4	Actual track record of debt servicing	5	0	5	5	5	5	2.5	2.5	3.8	5	5	0	5	0	0	0
D5	Power purchase and fuel purchase creditors	2.5	2.5	2.5	2.5	0	2.5	0	0	0	2.5	2.5	0	1.3	0	0	0
D6	Level of receivables (Days of sales)	2.5	2.5	2.5	0	2.5	0	0	1.3	2.5	2.5	2.5	0	0.6	0	0	0
D7	Funding of pension & gratuity liabilities	3	2	2	3	2	3	2	2	0	1	1	2	0	0	0	0
D8	Projections	6	2.5	2.5	1	3.5	0.5	2.5	3	1.2	1	2	1.2	1.2	1	1	1.2
E	**Others**	*5*	*4*	*4.5*	*4.5*	*4*	*3.5*	*3.5*	*2*	*2*	*3.5*	*4*	*2*	*3.5*	*3.5*	*0*	*1*
	FINAL SCORE	**100**	**71.5**	**68**	**64**	**64**	**60**	**52.5**	**51.4**	**49.4**	**47.5**	**45**	**42.8**	**41.1**	**35.9**	**33**	**11.2**

Source: ICRA/CRISIL 2003 (for the Ministry of Power)

This newer phase of reforms also involves greater consensus-building, and appears to bring the entire system towards a more inclusive mode (with public hearings, web posting of information, etc.) Notably, the Regulatory Commission Reform Acts do not mandate such public hearings, but the SERCs choose to do so (Ahluwalia and Bhatiani 2000). In addition, while there are public hearings and the like, the ERCs act very rapidly, with typically only several months gap between drafts of orders (made public) and their taking effect. Critics counter that the periods for open review and hearings is often very short, as little as 30 days in some cases.

As an example of the attempts at cultivating public opinion, a full-page ad taken out by the government touting its power sector reforms and success, and advocating power for all by 2012, stated there were 2,100 road shows "enacted to **sensitize opinion makers, media persons, students and general public** on the need for power reforms and strategy for Power Sector development" (Prime Minister and Ministry of Power 2002 - emphasis as original). However, it is unclear what the full benefit of all these attempts at transparency will be, in that many of the appeals and reviews have been undertaken by interested parties and specific affected consumers (lobbies), and the average consumer is not a participant in the reforms process, except through some NGOs. In fact, there are many vested interests that fund, "educate," and push their agenda through certain NGOs. This has often been the case through many PILs.

Another tenet of the restructuring program is increased energy conservation and support for such moves, including demand side management (DSM). This is supported through the Energy Conservation Act 2001, which has standards and regulations as a component. Indian appliances (like refrigerators, responsible for several percent of India's total consumption) are a number of years behind in terms of energy efficiency. However, India has yet to implement mandatory energy efficiency standards, or appliance labeling equivalent to the US yellow tag labeling. There has been the establishment of Bureau of Energy Efficiency, but its focus appears to be on energy auditing and education of managers. There is no defined timetable for standards, nor have mechanisms been stated for inducing energy efficiency in industry (like partnerships, challenge programs, soft loans, etc.)

Financing and Past Debt

After the March 2001 Chief Minister's conference, there was a consensus to find a solution to the outstanding SEB dues (to PSUs), then about 41 thousand crore Rupees (of which interest/surcharge was almost 16 thousand crore). Under the Chairmanship of Montek Singh Ahluwalia, former Finance Secretary, the Expert Group on Settlement of SEB Dues submitted its report in May 2001. The aim was to come up with a one-time settlement scheme to ensure future payments would be timely. The report suggests reducing the surcharges by 50%, and securitizing the remaining dues through the issuance of bonds by the Reserve Bank of India (RBI). If the SEBs fail to pay for their fuel/power in the future, this would impact their central assistance and access to coal supplies. The report also recommended incentivizing states to undergo reforms (Ahluwalia 2001), including establishing State Electricity Regulatory Commissions, and metering distribution transformers. It is important to recognize, as indicated in the Report, that the main challenge is the ongoing (future) financial viability of the power sector, and clearing off the debts will not solve that.

SEBs complain that their finances consist largely of loans, and conversion to equity would improve their finances significantly. However, it remains unclear how much such a one-time solution would cater to solvency improvement, instead of mere liquidity improvement. That is, unless, they advocate their debt be wiped off, and the equity is allowed to operate with no minimum returns requirement? In such a case, the State balance sheets would take a hit.

Overall, states find it easier to access funds after undergoing reforms, especially corporatization. These entities can access state, central government, and even international (multi-lateral agency) funding.

Electricity Bill 2001

There is a major revamping of India's power sector planned via the Electricity Bill 2001, which is in Parliament but has not yet been passed. This pending legislation was originally planned for 2000, and was renamed for 2001, but is expected to come into force only some point in 2003.[51]

Main features of the Bill include (Govt. of India 2001):

- Generation free from licensing except for hydro units
- Requirement of techno-economic approval done away with
- Captive generation free from controls
- Open access to transmission lines
- Setting up of State Electricity Regulatory Commission (SERC) mandatory
- Open access in distribution to be allowed by SERC in phases
- Retail tariff to be determined by regulatory commission
- Trading a distinct activity permitted with licensing
- Formulation of a National Electricity Policy by the Govt. of India
- Strengthening anti-theft laws
- Establishment of Appellate Tribunal

This would be a major bill, revamping the 1910 and 1948 Laws, and extending reforms further. Fundamentally, it moves the country towards power markets, but it provides very little detail on the operations of such a system, e.g., the role of any independent system operator (ISO). It states that Regional Load Dispatch Centers will be responsible for grid operations, and failing their abilities or powers, the Central Transmission Unit (i.e., PowerGrid) will take over this role. The Electricity Grid Code referred to in the bill, as formulated today (PowerGrid 2002), states that these *entities will not trade power, but only facilitate power transactions*. The Power Trading Corporation, though designed to trade power, is not set up as an ISO. Both the Bill and the Code indicate Regional as well as State Load Dispatch Centers. This appears to be a poor design, as the synchronous grid should not operate with such granularity.

The Electricity Bill 2001 has a strong focus on bulk (High Tension) consumers, who can get open access to generators (captive or IPPs). However, it doesn't indicate how much surcharge the utilities can pose, for the losses they incur (loss of paying

[51] In India, many bills are made public as drafts, but almost always eventually get cleared. This is driven by India's parliamentary form of government, where the executive, by definition, has an operating majority in the house.

customer) (Mahalingam 2002). This tension, over paying customers that sustain the cross-subsidies of today, is one of the major issues facing the Indian power system.

5. States

The majority of states in India (22, if not more by now) have started the reforms process, mostly in the last few years. Even before official reforms, Karnataka had the first semi-unbundled power sector in the country, with a separate PSU in charge of generation, Karnataka Power Company Limited (KPC), established in 1970. However, there was still some capacity with the SEB, and true unbundling didn't begin in India until 1995-96, with Orissa's reforms. Even Orissa had a PSU for generating thermal capacity, but this was not considered an unbundled sector, with some capacity remaining with the Orissa SEB. We present below some details on the restructuring of various states, focusing on Orissa, Andhra Pradesh, Gujarat (to a small extent), and New Delhi. Orissa was not only a forerunner, but its reforms were under the aegis of the World Bank. Andhra Pradesh has also been ahead in reforms, and has received extensive World Bank funding for its reforms. Gujarat is an example of a well-developed state, but which has had mixed progress with reforms. Delhi, the capital, was unique in that its utility had extremely high losses (40+%), despite virtually no agriculture. This very recently underwent full reforms with privatization of distribution, only the second in India after Orissa. There are indications that Delhi's reforms incorporate lessons learned from the mistakes of Orissa.

Orissa

Orissa is one of the less developed states in India, based on average human development indices, but it also has some amount of large industry. Nonetheless, it was a somewhat non-obvious candidate for leading the reforms in India, and conventional wisdom indicates the reforms came not from within but due to World Bank and outside push. Of course, like most other SEBs, Orissa SEB (OSEB) was in financial difficulties, and didn't have the funding to improve its situation. The reforms in Orissa were not a success, and we explore some of the happenings and their causes.

Some of the causal factors for Orissa's reforms included (Rajan 2000):

Contextual factors:

- Poor Performance of the SEB (driven partly by a rise in thermal power over hydropower, as well as by other factors common to other states)
- Conditionalities by lending agencies (World Bank)

Trigger factor:

- Inability of the state government to support the utility

Facilitating factors:

- Support of the government
- Absence of a powerful lobby (relatively low agricultural consumption)
- Support of top management

The process of reform began in November 1993, through discussions with the World Bank – who were already involved with financing a hydropower project in the state, which was facing rehabilitation difficulties – on how to improve the operating performance of the sector, and draw investment. Based on these, an agreement was signed between the Orissa Govt. and the World Bank (WB) for a reform process, and this was later reviewed and approved by the Chief Minister and his cabinet in 1995 (Rajan 2000). Based on the WB agreement and reform program, the reforms would consist of:

- Restructuring of OSEB via unbundling and corporatization
- Privatization of generation, grid corporation, and distribution
- Competition for new generation capacity
- Separate regulatory body
- Tariff Reform

Out of the estimated one billion dollar extra expenditure for the restructuring (loans), $350 would million come from WB loans, and the UK government would also provide DFID support for around $100 million.

The blueprint and milestones for the reforms were drawn up via the World Bank's Staff Appraisal Report (SAR), and the reform experiment was ready by 1995. The process was as follows:

1993 Chief Minister announces power reforms plans.

1994 Planning for reforms continue.

1995 Regulatory Reforms Bill passes in the state legislature.

1996 Orissa Electricity Reform Act took effect on April 1, 1996. OSEB was divided into the Orissa Hydro Power Corporation (OHPC) for all hydel capacity and GRIDCO. GRIDCO inherited the transmission and distribution infrastructure, as well as the liabilities of the SEB. The already existing Orissa Power Generation Corporation (for thermal power) continued, but future generation capacity was to come from IPPs (Mahalingam 1997). Orissa Electricity Regulatory Commission (OERC) was also established.

No budgetary support was envisaged for any of the bodies, except the regulatory body. But, to help out the enterprises, their accumulated losses were to be written off, their assets revalued, and their liabilities readjusted (Mahalingam 1997). Based on the recommendations of various consultants, a depreciated replacement model was chosen to revalue the assets of OHPC and GRIDCO.

The assets of GRIDCO increased from a book value of Rs. 1,183 crore to Rs. 2,395.8 crore. There were also various liabilities, including to NTPC, and these were converted to a term loan of Rs. 1,148.9 crore, plus some significant short-term liabilities (Mahalingam 1997). The total capacity was 2,120 MW within these units.

1997 OERC issues first tariff orders.

1998 4 Distribution zones were established as separate corporations (still PSUs) out of GRIDCO. Even then, GRIDCO remained the single-buyer of power to sell to the 4 DistCos.

1999 The 4 DistCos were also privatized, with a release of 51% of the equity in each held by GRIDCO. 39% would remain with the state government, and 10% would be held by employees. The central zone went to AES Transpower,[52] the US multinational, and the other zones went to BSES. Workforce allocation and severance were long, drawn out processes according to most reports. To facilitate the sale, GRIDCO accepts deferred payments, which affects it cash flow position significantly later on.

Orissa Government divests 49% of its stake in OPGC, via competitive bidding. AES wins with a Rs. 6.03 billion bid, giving it operating control of 2

[52] Technically, this went to an AES Joint Venture, but AES had 95% stake. Most companies entering such projects choose to form Joint Ventures or create subsidiaries, like Enron's Dabhol Power Company. This helps insulate the parent company.

x 210 MW thermal plants in Ib Valley. These plants were commissioned in 1994 and 1996, at an investment of Rs. 11.35 billion (Iyer 2000). Not all of the bid was towards assets; fresh capital was also invested (8%, equal to Rs. 1.03 billion).

2000 GRIDCO's financials worsen, and debt levels of the companies rise.

2001 Government constitutes Kanungo Committee to examine the reforms process

AES withdraws from the central zone distribution. Government appoints an administrator for this zone. His appointment is stayed by the courts. BSES states it is not interested in taking up the central zone.

2002 The performance of 3 of the 4 zones worsens compared to the previous year (Southern, with BSES, is the exception).

That reforms are not straightforward, nor can private operates easily succeed is illustrated by the attempt in September 1996 to hand over one section of distribution (the central zone, which included cities like Cuttack and Bhubhaneshwar) to BSES for operation, under a management contract. After the first 6 month review found negative performance, the management contract was terminated in April 1997. In response, BSES stated it was not given enough time to effect change, disputed the baseline numbers, and said that it never really had control over the staff (Mahalingam 1997), a concern for any reform mechanism based on outsourcing.

Also, AES came into distribution somewhat reluctantly (Mahalingam 1998). It was originally in the state as a power generator (IPP), with the 500 MW (250 x 2) Ib Valley Project. However, during the privatization process, BSES was the only eligible bidder for the 4 zones, after Tatas withdrew from the central zone (Prayas 2001). But, to ensure they didn't get all the zones, AES was persuaded to take over the central zone.

Results

The reforms were supposed to improve the power position in Orissa, but peak shortages continue. The finances of the companies have worsened to some extent, and the losses continue to mount (financial as well as technical). GRIDCO failed to pay generators what it owes, citing failure of receiving payments from the DistCos. Had they received their money, the generators (OHPC and OPGC) have a book profit of Rs. 768 crores between April 1, 1996 and March 31, 2001 (OERC 2002).

The WB-SAR based report called for a number of milestones, details on which can be found in Prayas (2001). Most of these were based on structural changes, like setting up the distribution zones, having OERC issue tariff orders, etc. However, some of these had negative operational effects as well. The goal of 16% return for OHPC along with its valuation hiked the costs to GRIDCO *significantly,* by hundreds of percent. This is an indication that the via the reforms process, as profitable companies come up along the power sector (generation, transmission, and distribution), this will raise the average cost of power compared to today's loss-making utility.

One casualty of the reforms process was rural electrification. Private companies were not interested in such loss-making operations. The agricultural demand for power went down from a low 6% in 1992-93 to a very low 3% in 1999-00 (Kanungo Committee 2001). But yet, the finances didn't improve. *This highlights the importance of mechanisms to ensure rural/underserved areas are catered to.* Either specific targets must be set and met, or an outside entity should be entrusted with such a role. Rural cooperatives might be one solution for such consumers. The noted environmentalist Ashok Khosla points out that if communities treat electricity as a shared resource, they would manage it better, as they have done historically for things like a shared water supply (personal communication).

What went wrong

Some of the main problems with the operations of the sector were relating to cash flows. OERC limited the increase in tariffs (citing that not all costs could just be passed on to the consumers – e.g., for bad performance – unlike the pre-reform days). This created losses for the DistCos, who also had deferred payment agreements with GRIDCO. GRIDCO, owned by the Govt. of Orissa, was caught between the increasingly expensive generators and non-paying DistCos, who were unable to improve performance as expected. While the exact numbers have varied over time, some details are as follows (Prayas 2001): GRIDCO was owed over 7.7 billion rupees by the 4 DistCos as of March

31, 2000. Of this, CESCO (the central zone operated and majority-owned by AES) owed Rs. 1.6 billion. But, GRIDCO owed OPGC, of which AES owned 49%, some Rs. 1.8 billion. AES shut down a power plant for a week in protest, and the crisis escalated with the Govt. threatening prison time for its officers (under the Essential Services Act). The compromise solution involved the government promising to pay its dues in 15 days.

After the reforms, GRIDCO's and DistCos finances went down because of a number of factors (Prayas 2001; OERC 2002):

- The bulk of the liabilities went to GRIDCO, Rs. 16 billion vs. 6 billion for all the Distcoms.
- Assets of GRIDCO were revalued upwards, to help match the increase in liabilities. This had operating implications, like the increase in depreciation costs.
- OHPC's tariffs were increased to meet the 16% returns. Overnight, the tariff went from Rs. 0.1 to Rs 0.49/kWh in 1996. Even central station's power was expensive, and GRIDCO had to offtake such power.
- There were unrealistic T&D losses estimated during the unbundling process. *This stresses the importance of accurate baseline information, and realistic performance targets.* The forecast for T&D reduction from 39.5% in 1996-97 to 22.7% 2000-01 wasn't achieved. Even the initial assessment of 39.5% for 1996-97 was grossly incorrect. A later audit showed this to be 49.4%.
- Tariff increases were lower than in the WB-SAR.
- There was no budgetary support via subsidies.
- The growth of load, especially profitable load, did not materialize. The WB-SAR called for 7,009 million kWh for railways plus industrial high tension (bulk) supply, while the actual sale in 2000-01 was 2,760 million kWh. This affected not only the cross-subsidy potential, but the T&D losses as well.
- Poor collection rates from consumers. Distcos achieved only 75 and 76% collection in 1999-2000 and 2000-01, respectively.

In addition to these issues, we find several other factors at play. Not enough was invested in this sector towards the reforms. Less than half the money from just the World Bank was spent, making the total fraction utilized based on the billion dollar estimate even lower (Kanungo Committee 2001). Critics will point out that a significant fraction went to consultants, 306.422 crores (but the bulk of this came from DFID funds, and none came from consumers). There was also a cyclone that hit just after privatization, before proper insurance was in place, causing not only a financial loss, but a major operational challenge.

The AES episode created a lot of controversy, with their reporting Government interference and lack of law and order, but the Kanungo Committee Report (2001) counters a lot of difficulties were caused by AES practices (Annexure-9). They created a new management cadre, which caused a lot of resentment within CESCO, the Central DistCo. In addition, they came in to CESCO expecting to take up an additional 2% in OPGC, giving them 51%. When that didn't materialize, that triggered their desire to sell their state in CESCO in 2001.

However, the biggest reasons for the poor performance appear to be the false assumptions and expectations of the players, and the limited support provided by the government, either for subsidies, or to the companies who had liquidity issues in addition to solvency issues. Money coming in from outside sources was often diverted to state budget needs, and there remained significant institutional lethargy and morass in the sector. The government failed to pay its own dues for power, some Rs. 1.5 billion.

Some of the lessons from the Orissa experience, other than the obvious ones like not getting the numbers wrong, include (IDFC 2000):

- Incomplete separation of transmission and distribution can cause problems.
- Regulators should give a clear picture of their tariff philosophy, rate base, valuation methods, likely profile of prices and expected performance levels.
- There should be a structured, time-bound financial support mechanism, with a fixed schedule for tapering off coupled with improvements in operating parameters and collection.
- The single buyer model is necessarily not the best, and the Transco might be better as just a wires company.
- Determining who gets priority claims over revenues is important. Do not escrow the revenues from the distribution zones for meeting TransCo needs, like was done in Orissa.
- Don't tinker with valuations, especially just before privatization. This can have a serious impact on tariffs, as Schedule VI of the Supply Act 1948 is based on assets (and newer methods allow for 16% returns on equity).

Andhra Pradesh

Andhra Pradesh (known as AP) is a large state considered to be the northern-most state in South India. Since 1995, it has been governed the by techno-savvy Chief Minister, Chandrababu Naidu, a central figure in the reforms process. The state's policies have been progressive, and it is considered a success in terms of IT, but its human development indices are generally below the national average. A closer look indicates that much of the success has been in the cities, and the benefits of plans have not trickled down to the villages. Naidu has been successful in pushing reforms, no matter how unpopular, such as reducing food subsidies. However, perhaps with an eye towards upcoming (2004) elections but also driven by his push towards rural empowerment, Naidu announced in August 2002 that the state should be power surplus, and that agricultural power supply would be guaranteed at 9 hours per day, a big improvement over then supply. Of course, AP was not power surplus when considering agricultural supply rostering. What AP had done was to separate rural domestic/commercial from agricultural supply (through phase-wise isolation of feeders), and promise that rural domestic/commercial supply would not get cut off when agricultural supply was curtailed (a major step, compared to many parts of India), and that agriculture would also get 9 hours per day of 3-phase supply. This plan, despite the increased capacity in the state and purchases from outside to meet full demand (excluding agriculture), put immense burden on the utilities (APTransco), whose finances were projected to take an annual hit of close to a thousand crore to meet such increased supply. This scheme was also in the political spotlight, and opposition parties harped on several power cuts and failures (and they promised free power for some consumers instead). In retrospect, such power cuts were not uncommon previously, or presently in most of India. But the lofty promises made them a political target, and power sector reform promises to be one of the largest election issues in the state. As mentioned before, protests against tariff hikes in 2000 turned violent, but the AP government still vowed to proceed with reforms. When considering the success of AP's reforms, political will is possibly the most important factor, coupled with the efforts of management at the utilities. The key has been not only efforts at policy, but *execution*.

The APSEB was established in 1959, similar to many SEBs in the country, and was unbundled in 1999 as part of ongoing power sector reforms. By June 1997 there was a public policy statement to unbundling, and the required legislation was enacted in February 1999. This split up APSEB into APGenCo and and APTransCo. The APERC was also instituted, and it has issued 3 tariff orders to date. According to utility officials (and examining its tariff orders and pronouncements), it appears quite independent.

AP's power sector is quite large, with a capacity close to 8,000 MW. Compared to its capacity, it faces poor consumer averages, with one of the highest number of pumpsets (over 1.8 million) and number of consumers (some 12 million) in the country. Noteworthy points about the sector are that AP has had some of the greatest success with IPPs (driven by not only political will but also because Godavari Basin natural gas is available). 1,060 MW of IPP power was added in 5 years, from 5 different projects, one of the highest in the country.

While financial concerns are a fundamental driver for reforms, SEB losses are a somewhat recent phenomenon. In 1994-95 APSEB earned a profit of Rs.87.25 crore, but in 1995-96, losses came to Rs.1,244.68 crore, climbing to Rs.1,533.04 crore in 1996 – 97 (Reddy 2000). This was not due to some enormous change in operations, but rather financial and book restructuring, with the AP govt. writing off almost 1,000 crore of its equity in 1994-95. After this period, debt liabilities increased enormously, to almost one-third of expenditure by 1996-97.

In looking at the reforms, the first step was likely the 1995 high level committee, chaired by Hiten Bhaya, to suggest reforms to be introduced in the power sector (Reddy 2000). While focusing on unbundling APSEB and operating on commercial lines, as well as tariff rationalization, the World Bank commented that the Hiten Bhaya Report didn't go far enough with the reforms process. The regulatory commission should focus on all tariffs, and full unbundling, without holding companies, should be the way forward. The World Bank also advocated a minimum 50 ps/kWh for agriculture. While the AP government stated the WB role was only advisory, studying the reform paper showed nearly full correlation with such recommendations (Reddy 2000). Driving ahead with reforms, the government pushed the Andhra Pradesh Electricity Reforms Act of 1998 through with stunning speed. The Telugu Desam Party government introduced the Bill on April 27, 1998, which was passed within one day. Helping ensure its smooth passage, the entire opposition was suspended from the Assembly (Reddy 2000).

Because of its reform programs, AP was the beneficiary of the a major portion of World Bank funding in India, and it received 6,600 crore of loans towards total reforms, two-thirds of which were for the Andhra Pradesh Power Sector Restructuring Program. These loans were under the Adaptable Program Loan (APL). Such disbursements were despite sanctions imposed on India after its May 1998 nuclear tests.

The reforms created a GenCo, a single-buyer, APTransco, and (eventually) 4 distribution companies (by geography). The DistCos were only hived off from APTransco in April 2000. The borders for the 4 DistCos were chosen not on operational grounds, but to ensure that no one company had an extreme mix of consumers (too many agricultural or all the paying, i.e., industrial/commercial, customers). In the AP model, the tariffs set by the APERC would be based on annual revenue requirements, and any subsidy beyond the allowed cross-subsidy would be borne by the state. However, the bulk-supply rates charged to the various DistCos is unequal, factoring in its customer mix and ability to pay. In 2001-02, the gap in the ARR calculations of Rs. 2,062 crore[53] was filled by efficiency gains of Rs. 501 crore and a Govt. of AP subsidy of 1,561 crore rupees (APERC 2002). These subsidies are paid out to the DistCos, who pay full bulk supply tariffs to APTransCo.

In terms of privatization, the government has scaled back its plans to privatize the DistCos anytime soon, citing troubles in Orissa with rushing into things. They also want to bring down losses in the system, perhaps to increase the likelihood of a successful sale. Observers point out that the government may be waiting until after the 2004 assembly elections for doing so. The Eastern Company will likely be the first on the block, given its better financial position, despite the higher bulk supply tariff it faces. The entire

[53] There was no tariff hike, but revenue collection was close to 100% of the target, partly because of aggressive steps to collect past dues.

privatization process (and even transition process) is under fire over valuation of the assets of the utilities. Critics point out that the values assigned to some of the DistCos are extremely low, especially considering the substantial real estate they have for commercial buildings (not just Rights of Way) (Sridhar 2000).

The APERC is considered independent, and has a retired Civil Servant as its Chairman, and the other members are a tax official and former APSEB officer. It has a strength of 60 staff members (high for SERCs in India), and has issued some unique pronouncements in terms of power. They have published a "cost to serve" model, whereby the different classes of consumers have different costs explicitly calculated on *economic* grounds. (We examine APERC's tariff orders shortly.) They have also issued an order to the utilities to meter *all* consumers within 3 years. The APERC tariff orders have been challenged in the courts, but the Tariff Order for 2000-01 was upheld in the Supreme Court in March 2002. Many more cases were ongoing in the Supreme Court (6 cases) and the High Court (nearly 100 cases) in 2001 (Prayas 2001).

In addition, while the APERC is transparent in its orders, it doesn't comment on most PPAs (citing grandfathering). However, critics point out that these are not only non-transparent, but also a major cost for TransCo (Reddy 2000). While they don't want the tariffs revised, necessarily, they at least want the agreements to be made public. The PPAs are especially a concern given the high guaranteed offtake, often 80 or 85%. In addition, APERC appears to be siding with the utilities on some grounds (while questioning them on many others, though, like T&D losses). APTransco filed a petition on Wheeling Charges (carrying power from private generators to bulk consumers), asking for Rs. 1/kWh as the charges. According to APERC's orders, the new wheeling charges are now set at Rs. 0.50/kWh in cash and compensation in kind for system losses of 28.40% (Prayas 2001). This effectively comes out to more than one rupee per kWh. APERC is also limiting captive power (which is what the utilities would like), citing it is mainly for emergency use or where even one second of outage matters.

In terms of government decisions, beyond supporting the reforms, steps have been taken to reduce theft. There has been a new anti-pilferage act, in July 2000, which is almost draconian. Convictions trigger mandatory 3 or more months of jail, a Rs. 50,000 fine, and 2 years loss of supply. 3,000 people have since been jailed, and 250 utility employees have been arrested. Discussions with utility officials indicate that commercial losses have fallen an estimated 2-3% after the laws were enacted. In addition to this, there is a continued thrust on rural electrification and access, such as a directive to add 50,000 pumpsets per annum. There is a scheme available whereby a pumpset can be added on demand, if the farmer wishes to have metered (but still subsidized) billing.

APERC Tariff order 2002-2003: An Analysis

This is the third tariff order promulgated by APERC, and follows the model whereby tariffs are determined by the APERC, and utilities must follow the pricing models. An Annual Revenue Requirement (ARR) analysis leads to the costs that each utility would face, and any shortfall from the revenues must be borne by the State. APERC allowed explicit subsidy by the state, which had to be paid to the DistCos. APERC announced Bulk Supply Tariffs (BST) that the Transco would charge the DistCos (aka Discoms). In arriving at its calculations, APERC invited petitions and presentations from various parties, not only the utilities and the State, but also consumers. Notable among the challenges to submitted information were the transmission losses claimed by APTransco, and the amount of consumption by agriculture (submitted by the DistCos). As per APERC, "The tariff design was further rationalized to achieve the objectives set forth in the Reform Act of 1998. Attention was on i) rationalization of categories; ii) rationalization of tariffs and iii) incentives for incremental consumption by HT consumers."

The tariff order modified the slabs as well as the tariffs for many consumers, and introduced an optional metered tariff for agriculture. Any takers-up could find lower tariffs than the flat-rate tariff, assuming low to normal consumption. There were also incentives to consumer more electricity for bulk consumers (industry), with rebates given for higher usage.

What is interesting is that APERC defines so-called "cost to serve" tariffs, which are its calculations of full-cost tariffs across the various sectors.

Table 14: APERC's Cost to Serve Consumers by Category

	Cost to Serve (ps/kWh)
LT1 – Domestic	410
LT2 – Commercial	338
LT3 – Industry	269
LT4 – Cottage Industries	316
LT5 – Agriculture	238
LT6 – Local	295
LT7 – General	312
HT1 – Industry	244
Railways (Traction)	226

Source: APERC Tariff Order 2002-2003

We can see that these "costs to serve" numbers must be based on strong assumptions. How else can it cost less to serve agriculture than bulk consumers like Industry? If we assume the Bulk Supply Tariff, i.e., the price that the single buyer (TransCo) must pay to its generators, is a controlled and fixed cost (around Rs. 1.80 on average in Andhra Pradesh for 2002-03), then we should *incrementally* calculate the costs to deliver the power. This will especially be the case with separate distribution companies, who today pay a flat rate for all their kWh purchased from the TransCo. Agriculture contributes the most to the system losses, given its high technical losses (long, Low Voltage runs), higher investments in such long runs, higher associated theft, and higher power quality degradation (power factor). Compared to bulk industry, it also consumes less power on a load factor basis. The only reason the "full costs" have been calculated as such is because the cheapest generators are supposed to be available for such consumers. In addition, the variable costs are the primary charge taken, as fixed costs are recovered by other consumers. The categories of costs for the "fully allocated costs" are Energy component, Demand component and Customer service component (APERC 2002). The trick lies within the Demand component, which is based on coincident demand. There has been the loose assumption that agriculture can be powered during off-peak hours. However, given its large load and, often, long hours of supply (9 hours in Andhra Pradesh), the so-called off-peak actually goes away. Figures seen from AP Transco indicate a night-time (agricultural supply time) usage about 98% of the daily peak!   We can see how *tariff philosophy* followed by ERCs strongly affects tariffs, economic viability, and even operational efficiency.

Other issues with the Tariff Order include a very limited “reasonable return” for the DistCos (after the annual revenue required calculations), very low compared to the 16% that private companies expect. In addition, the Bulk Supply Tariff is flat; there is no Time of Day or Time of Use signaling. This is bad for dispatch to generators, and doesn’t inculcate efficient consumption patterns.

Gujarat

Gujarat is an industrialized state in Western India, and has been pursuing reforms since 1999 (under the cover of the central ERC Act of 1998). Despite high per capita consumption of power, and high state electricity duties (earnings for the state – some 1/3 of the total such duties in India), the power sector is considerably underfunded and loss-making. The Gujarat Electricity Board (GEB) continues to provide generation, transmission, and distribution in the state, but there are a number of private (and central) generators in the state.

The city of Ahmedabad operates under Ahmedabad Electricity Company (AEC). This private operator, established in 1913 is profitable (and publicly listed), but the same is the case for other companies operating in urban areas. AEC has paid a steady dividend, but recent changes in supply costs have reduced the dividend from a peak of 25% in 1999-2000 to 18% in 2000-01 to 10% in 2001-02. Notably, the Torrent Group (primarily a pharmaceuticals company) is the largest stakeholder, who also have a stake in Surat Electricity Company (the private electricity operator in Surat, also in Gujarat), and they also have interests in generation. The remainder of AEC is held by financial institutions, private investors, and the Gujarat Govt. (almost 20%).

While we do not examine the details of the Gujarat power sector, some observations include the fact that the reforms process has slowed down, partially due to external factors. A massive earthquake on January 26, 2001 caused massive state-wide difficulties, and there were also widespread riots and elections in 2002. All of these factors combined to slow down the reforms process, which clearly requires political will and support of the government.

Delhi

Delhi, the state that includes the capital, New Delhi, used to have its power supplied by the Delhi Vidhyut Board (DVB). DVB, itself the reincarnation of the Delhi Electric Supply Undertaking (DESU), was in the extreme position of having very little generating assets, some 300 MW, relying on outside (largely central) generators for its power (peak loads are over 3,000 MW). Despite being an urban area, and hence, almost no agriculture, the theft and losses were very high, estimated at 45+%.

While most other states underwent or are undergoing reforms in stages, Delhi underwent reforms with a bang, though the initial reforms came under the central government ERC Act of 1998, creating the Delhi ERC in 1999. The Delhi Electricity Reform Ordinance was promulgated in October 2000 and was replaced by the Delhi Electricity Reform Act, 2000. It's worth noting that the Delhi ERC is understaffed, in fact lacking 2 Commissioners (it only has one Member, the Chairman). Subsequent reforms were undertaken in 2002, when it unbundled its utility (into 3 zones) and privatized them at once (June 27, 2002).

Learning from the Orissa experience, the main metric for choosing companies was not based on valuation, but on performance improvement goals. The DistCos annual revenue requirements are calculated, based on their expenditure, performance (targets), and return on equity (16%). They pay the TransCo, a government company, a realistic lower amount, based on the collection. Over time (5 years), this amount would match up to the full costs. In the interim, the Transco will receive Rs, 3,250 crore as subsidy to cover its costs to generators vis-à-vis the lower amount of money the DistCos would be paying. One other feature is the retail tariffs are known to the DistCos in advance, and were fixed by the ERC. The Delhi ERC also announced the total losses in the 3 circles, averaging 50.7%!

Details of the process of choosing the companies are given below, based on the Distribution Policy Committee Report (Ministry of Power 2002) and discussions with Government of India and DistCo officials.

- *Valuation of assets*: This will be based on "Business Valuation." Based on reasonable assumptions of retail tariffs, efficiency improvements, and expenses in the future, assets are valued such that the company can become viable in a fixed period of time. The liabilities are also considered this way, with some portion going to the successor companies, some left with a holding company or refinanced, and some covered through tariff increases.
- *Mitigating uncertainty*: Based on the annual revenue requirement calculations, and bulk supply tariff will be set such that the company can make the required returns, assuming a performance target is met. The difference in such a price and the cost to the TransCo will be covered by the Delhi Government. Such support will effectively lower the price for the DistCos, making them viable from day one.
- *Criteria for selection of successful investor*: A 5 year period, 2002-07 is the operating period for which bidders give their performance improvement targets.
- *Incentives for achieving higher efficiency gains*: The benefits of doing better than the targets will be equally shared between the consumer and the DistCo, and underperformance will be borne entirely by the DistCo.
- *Baseline data*: The Bulk Supply Tariff Order has been released by the Regulatory Commission in response to the filing by DVB before bidding closed.
- *Treatment of receivables*: Past dues will be transferred to the Holding Company. If these are recovered, 80% will go to the Holding Company, and 20% to the DistCo.

The stated losses (subsidy requirement) for the 5 year period (covered by support to the TransCo) will be Rs. 3, 250 crore. These are reported to be in the form of a loan, under terms to be worked out subsequently. It would be important to consider various exit strategies, in case the TransCo is unable to repay the loan. In comparison, just before the reforms, from 2.4 million customers, and 19 billion kWh of sales, an annual revenue of 5,400 crore was required, with a gap of 1,100 crore rupees. The bidding processing revealed the issue of limited players, as initial interest was shown only by 6 parties. Only Tatas and BSES submitted final bids, and only BSES submitted bids for all the 3 zones. Tatas won the North West Delhi Distribution Company, while BSES took the South West and Central East Companies.

The main risks the utilities say they face are that they either fail to meet the loss reduction performance targets, or they fail to collect from consumers. They state the government has been quite supportive, including by passing an anti-theft law, making electricity theft a cognizable offense. It also gives them power to disconnect non-paying users, even government users. While the DistCos mention they worry about the accuracy of data, fearing Orissa-like effects, the reverse is true from the consumer and system perspective. Without accurate *benchmarking*, the DistCos might have an incentive to petition the ERC that the initial losses are actually higher than they truly are.

BSES states that labor is a non-trivial issue, as the workforce was handed down as part of the privatization process. Nonetheless, they say the bigger cost is infrastructure upgrading, to improve operations, metering, and collection. Some of the recent ERC orders they must comply with are the installation of electronic (solid state) meters, and metering on all the distribution transformers. Footnote 62 on page 91 gives some details about why top-down orders relating to technology might be a bad idea.

Table 15: Current status of reforms in key states. Not all states need have unbundling to have proceeded with reform. E.g., Maharashtra has a strong regulatory commission, but has not yet unbundled. Also, there is often a lag between when the state legislature passes an act, and when it comes in to force.

	Orissa	Haryana	Uttar Pradesh	Andhra Pradesh	Karnataka	Rajasthan	Delhi	Gujarat
Date of instituting Reform Act	April-96; (Passed In 1995)	July-97 (date passed in legislature)	September-98	October-98	June-99	June-00	April 1998 (Central Act)	April 1998 (Central Act)
Regulatory Commission established	1996	1998	1998	1998	1999	2000	1999	1999
Utility unbundled	Yes	Yes	Yes	Yes	Yes	Yes	Yes	pending
Separate distribution companies established	Yes	Yes	Yes (partial)	Yes	Yes	Yes	Yes	No
Distribution Privatized	Yes	No	No	No	No	No	Yes	No

Source: Planning Commission, Respective SERCs

6. Finance and Tariffs

One lesson that many Indian power policy makers need to understand is that payments for infrastructure can only be by consumers or taxpayers. Private players will only invest expecting to take more out, and multi-lateral agencies do not want to pay for capital costs of infrastructure as a grant.[54] While the laws starting with 1910 all wanted utilities to be profitable, the reality has been significantly different.

The entire reforms process is meant to bring in efficiency, beginning with controlling costs. However, *privatization does not necessarily mean competition*. Without true competition, it is unclear how much reforms will lower costs. If one looks at costs of generation, after opening up the sector to private generators, the costs have increased dramatically, even for PSUs. Some of this is because everyone attempts to enjoy tariffs with the 16%[55] return on equity (based on the KP Rao committee). Looking at the price of power from generators, both the variable and fixed costs can be somewhat higher than comparable projects, especially for the CCGT plants that have been the favorite of IPPs. While fuel costs are out of generator purview (often using liquid fuel because of limits on gas – part of a policy to allow 12,000 MW of such power), capital and other costs are not. Analysis indicates there simply was not enough competition to bring these costs down.

The Ministry has indicated that they now require more transparent, competitive bidding for projects, unlike the earlier MoU-based route (CERC (prepared by PriceWaterhouseCoopers) 2001). It must be emphasized that these are primarily bids for plants, not electricity in a market sense, and scrutiny is based on a costs-plus model. Even if new PPAs are based on competitive bidding, there are a very large number of ongoing projects that will be grandfathered and kept unchanged. The earlier regime of power purchase agreements has come under fire, especially when non-transparent. Even when transparent and blessed by the regulator, these effectively bind the utility to purchasing power at a pre-specified price for many years, often for 25 years or life of

[54] Told to Indian Power Sector Delegation visiting the US, in Washington, DC, by Clive Harris, The World Bank, on October 8, 2002.
[55] When factoring hidden mechanisms for (legal) earnings, e.g., operating at higher load factor than nominal, the returns could be much higher. See *Tongia and Banerjee 1998* for more details.

plant. Even worse, these contracts often call for high off-take, with a take-or-pay clause for the fixed costs. Without such agreements, generators are wary of establishing capacity. But, these hamper the operation as well as finances of the system.

When comparing projects, it must be mentioned that there is often confusion (or purposeful finessing) over different types of calculations. Most generator tariffs quoted are a single number, when, in reality, the tariff varies over time. Indian tariffs are front-heavy (or at least have been, until recent CERC attempts to reduce this), especially because of depreciation and debt-servicing pass-through (the equity garners the 16% returns). The tariffs are then levelized at a 12% discount rate. No one questions why the levelizing rate should continue to be 12% for such calculations. Should numbers be nominal or real costs? For better results in the costing process, *not only must the assumptions be made transparent, but they should also be challenged regularly*.

Moving beyond generation, if the entire system were to truly allow 16% equity returns across the board (like private distribution companies seek), then that would significantly increase the cost of delivered power, assuming other parameters like losses remain unchanged. We examine possible scenarios in the section on Fundamentals later.

Given operating costs are a pass-through (to consumers), the main mechanism to reduce generation costs involves control over capital costs (which can mainly come about through competition or very strong regulation), and control over finances. One criticism of existing tariff structures is that they are quite intrusive when it comes to finance. Debt and equity are treated differently, and some economists and international analysts have questioned such a policy. In theory, the market should account for these, leaving such choices as an internal (company) decision. Restrictions on finance will likely reduce the room for innovation and flexibility when it comes to financing new projects, hurting its development.

The SEBs complain they are indebted in perpetuity, with little or no equity coming in from the states. But, as private players come in, they all seek the allowed 16% return on equity. The underlying basis for the 16% return on equity was based on the bank (RBI) rate, plus some percentage. However, by no longer keeping the relationship explicit, project financing has not taken advantage of falling interest rates. NTPC, for its

Shimadri project in Andhra Pradesh, obtained special international funding from Japan. The question becomes, in an environment where debt obligations are passed through, what incentive does a utility have to find cheaper debt (or be honest about such debt – especially through refinancing)?

The Playing Field

Reforms are supposed to usher in a level playing field, and the recent move towards distribution reforms is a step in the right direction. Nonetheless, it does not correct a serious imbalance in the Indian system that focused on different segments of the system, often at the expense of others. Generation received most of the funding up through the mid-1990s. While returns on equity were specified, generators were allowed 16%, while transmission companies began with 12% allowed (or lower) (Raman 1997), while the distribution utilities were only asked for a 3% return on asset base (and failed at that, by far). Even within generation, from 1992 onwards, IPPs were allowed the 16% returns, but Central Generation Stations only were allowed 12% returns during the early and mid 1990s (Ahluwalia and Bhatiani 2000). Transmission tariffs were not thought of as a special case, and were set on a single-part tariff basis. Even PowerGrid, which was the first unbundling of transmission, was recognized as a generating company.

Despite the poor health of the India power sector, NTPC (like REC) enjoys a AAA credit rating. NTPC is an efficient utility, and very profitable. NTPC most recently showed a 19.8% profit! In comparison, International Power PLC (spun off from National Power PLC), which has 10,000 MW of capacity and is also focused on generation, had revenues of 811 million dollars (FY ending Dec 2001), a profit of 100 million dollars, and its return on capital invested was only 7.6% (www.hoovers.com), significantly lower than the targets NTPC has declared. The bottom line is that it is very easy for generators (public, private, whoever) to be profitable when all that does is increase the price for the downstream system. This leads to the next question of whether generator prices are higher than they should be. CERC believes so, and has struck down some allowed cost increases and charges for NTPC (which complains it faces an unequal playing field vis-à-vis IPPs).

Government policy, briefly, explicitly favored some projects over others, e.g., through its 1998 Mega Power Project Policy, which would give incentives like customs duty waivers and tax sops for large projects serving multiple states.[56] These were criticized by other generators, and there were operational difficulties such as fuel linkage, setting up enough transmission capacity for their power, etc. Most importantly, financing and escrow for such large projects became a bottleneck. Perhaps the greatest unequal playing field was offered to the fast track projects, and the importance of the central government guarantee can not be overstated. Nonetheless, after criticisms, and the specter of Enron invoking it, the government announced it would not issue such counter-guarantees any more.

The market is supposed to address issues of fairness, in that risk and rewards are linked. The earlier regulatory environment favored generators (especially IPPs), who could pass through many of their risks to consumers. While still the case, the question becomes who bears most of the risks, and are they rewarded so? There is a recognition that as utilities improve, some of the benefits must be passed on to the consumers (like in the Delhi model), not just kept with the power company.

From a consumer perspective, the playing field is clearly not level, with some classes heavily cross-subsidizing others. Even looking at a particular segment, like industry, we see state-to-state variations. E.g., Tamil Nadu has increased drawing investments as they have reasonably lower industrial tariffs and provide quality power to this sector. It is possible that competition between states will allow innovation and experimentation in determining useful solutions.

Cash Flows and First Rights

One of effects of the IPPs was the increased expenditure by SEBs for power purchases. The number of kWh and the price both went up, so their finances went from bad to worse. In addition, IPPs and outsiders outsider want first claim on free cash flows. IPPs want(ed) escrow accounts to cover their financial obligations. This practice was

[56] Infrastrucutre projects already enjoy five or ten years of tax holiday. In the distribution sector, if a private company pays dividends, those would be subject to taxes (as per current indications). Further tax reform is not likely to be a critical factor for the success of reforms, but the government is considering extending the tax holidays.

followed for a short period, but failed because of differences over what financing (debt vs. equity, domestic vs. foreign) should be covered via escrow accounts. Most importantly, there wasn't enough cash with the SEBs to cover more than one or two IPPs. The Deepak Parekh Committee, instituted after the difficulties over the Cogentrix project, came out against escrow as a viable long-term solution, instead favoring time-bound reforms by the SEBs.

In the new, reformed, regulated model, this leads to the question, "*Who has first claim to cash flows?*" Government entities often lose out in these calculations, evidenced by their outstanding dues (Table 11). If more and more generators privatize, these players will not be so forthcoming in accepting delayed payments. A similar question, unanswered, goes towards transmission and distribution companies when they are privatized, and are entitled to subsidies by the government (authorized by the regulatory commissions), but the funds available are insufficient. One suggestion by IDFC for helping ensure cash flows for private entities during the transition period revolves transferring where the subsidies come in, and is termed a distribution margin framework. Any (private) distribution company would first calculate its costs, including returns. It would then pay its suppliers, who keep their costs (plus returns), and then pass on what's left to the generators. If this is not sufficient, they would receive the remainder as subsidy from the state. As an example, assume the total cost of the power is 100 (25 DistCo, 5 TransCo, and 70 GenCo). Say the recovered amount is only 70, from the consumers. The Distco would keep 25, and pass on 45 to the TransCo. They would keep 5 and pass on 40 to the GenCo, who would receive the remainder 30 from the state. The values would be chosen by the regulatory commissions, based on Annual Revenue Requirement calculations.

Variations of this have been seen, e.g., in Delhi, where the government-owned TransCo will receive 3,250 crore rupees as assistance over 5 years to make up for the shortfall based on its own generation purchase costs and what the DistCos provide. It appears that politically, it is easier to give subsidies to a government entity than a private player. While in AP, today, the subsidies go to the DistCos, this might change with privatization. We will likely see several different models, all of which incorporate subsidies. These subsidies are meant to be temporary only. However, it is important to remember that none of these reform modes directly affect the fundamentals. It is hoped that private distribution (or even transmission) companies will reduce costs by lower losses (technical and commercial – aka theft) and improve collection. These companies could also provide the infusion of capital and technology in to the system, resources unavailable with the government. But, as long as the cost of supply and recovered tariff have a gap, the system will not be viable.

Where do the Reforms Lead?

That the end goal is seen as privatization is evidenced by the published views of the Secretary, Disinvestment Ministry (who used to be Additional Secretary, Ministry of Power). "It is well recognized that reforms cannot be meaningful unless competition and privatization are initiated. The center must, therefore, break up its generating CPSUs into smaller companies and introduce measures to enable competition amongst these companies. These could also later be selectively privatized for generating more resources for further investment and for reducing fiscal deficit pressures on the central government" (Baijal 1999). He speaks of a National Grid with time-of-day metering fixed through competitive bids. Such a market would also allow easy entry of new generation capacity without pre-determining the tariffs, i.e., with no PPAs. While a useful goal, it remains to be seen how soon a power market can be developed.

According to the Ministry of Power (2002), the 6 private distribution companies in the country (Tatas and BSES in Mumbai and elsewhere, AEC in Ahmedabad, CESC in Calcutta, SEC in Surat, and NPCL in Noida – the last being a relatively new entrant) have performed significantly better than other utilities, and have earned profits. The conclusion drawn has been that privatization of distribution will lead to better operations. What this fails to factor in is that all of these serve predominantly urban areas (BSES's Orissa operations are loss-making).

Competition and Tariffs

It must be emphasized that throughout the reform process, competition has been mainly for the front end, i.e., for groups wishing to take over certain functions (bidding for building a plant, taking over a distribution circle, etc.) Power is not sold based on bids, Power Trading Corporation notwithstanding. Competition for retail distribution will be non-existent (except, perhaps after the 2001 Electricity Bill – which has not yet passed, through direct access by IPPs and wheeling of power – which will logistically make more sense for bulk users) given that distribution is being corporatized or privatized along geographic lines. Within a zone, these today have exclusive rights (and responsibilities).

Throughout the reform process, the main competition when it comes to tariff will be for bulk tariff, not retail tariff. Fundamentally, the greatest variation in costs in the Indian system comes from *generator* costs. The TransCo and DistCo remain regulated (albeit corporatized or even private) monopolies (until the Electricity Bill 2001 passes, at least).

There have been a number of studies on tariff setting in the Indian context, including a paper by S. S. Ahluwalia (past Secretary, CERC) and G. Bhatiani (2000), which presents the entire rationale for moving to competitive bulk supply tariffs. They advocate some features of Performance Based Ratemaking, which offers more operational learning and flexibility, with less long-term constraints than costs-plus models.

In the Indian context, competition will likely come first in bulk supply (from the generators), and later to the basic consumers. This is simply based on the structures of the reforms thus far. On the other hand, with the Electricity Bill 2001, bulk consumers could potentially choose their suppliers. There is limited understanding between the timing and sequential nature of competition in bulk supply versus retail tariffs. Operationally, it is easier to move towards competition in the bulk supply market. This will be useful, and help the system move away from the current Power Purchase

Agreement mechanisms. This will still involve work through the use of load duration curves, and a philosophical shift that not all generators will produce the same relative quanta (68.5% PLF) of power.

In a move away from simply using generation (or deemed generation) load factors, CERC announced the adoption of Availability Based Tariffs (ABT). ABT is thought of as a tariff mechanism that promotes healthy grid operation, and will help in converting to a national integrated grid (compared to today's 5 regional grids). Here, generators would be paid for having their plants available for the system requirements (maintained through the RLDCs). The fixed portion of costs for generators would be a fixed liability for the states, as long as the generators were able to be available as per the contracts or requirements. Generators (and the states consuming the power) would be penalized for deviating from the contracted or schedule power levels, which would help promote grid stability. While drafted as a performance based tariff for generators owned/operated by the central government, it is likely that such norms will likely apply to IPPs and other generators, eventually. This is also a new system of scheduling and dispatch, which requires both generators and consumers (states) to commit to day-ahead schedules. There would be rewards and penalties (financial) for deviations from the schedules (with variations allowed only with one and a half hour advance notification), and enforcement of dues because of deviation would lie with CERC as per sections 44 and 45 of the 1998 ERC Act.

Salient features, taken from the Ministry of Power and CERC, include:

- "A fixed charge (FC) payable every month by each beneficiary to the generator for making capacity available for use. The FC is not the same for each beneficiary. It varies with the share of a beneficiary in a generators capacity. The FC, payable by each beneficiary, will also vary with the level of availability achieved by a generator.
- In the case of thermal stations like those of NLC, where the fixed charge has not already been defined separately by GOI notification it will comprise interest on loan, depreciation, O&M expenses, ROE, Income Tax and Interest on working capital.
- In the case of hydro stations it will be the residual cost after deducting the variable cost calculated as being 90% of the lowest variable cost of thermal stations in a region.

- An energy charge (defined as per the prevailing operational cost norms) per kWh of energy supplied as per a pre-committed schedule of supply drawn upon a daily basis.
- A charge for Unscheduled Interchange (UI charge) for the supply and consumption of energy in variation from the pre-committed daily schedule. This charge varies inversely with the system frequency prevailing at the time of supply/consumption. Hence it reflects the marginal value of energy at the time of supply."

While ABT helps generators move away from PLF as their sole metric for performance and earnings, availability alone might give them greater earnings since most generators can beat the availability norms prescribed, especially considering newer thermal stations. There is also a technical issue with using frequency as the measure of "peakiness" of the grid, since the Indian system often shows over frequency in the middle of the day, which is not quite off-peak but in between the morning and evening peaks. Using a 15 minute time interval is also an issue, since frequency deviations occur with time constants measured in seconds.

ABT was created with operational efficiencies in mind, but it might provide a useful starting point for structural changes in the system. By having day ahead commitments for power needs, it might be the first step towards a power pool or market.

Some details of how and why ABT came to be adopted are also instructive in learning about the decision-making process. As per the Ministry of Power, "ABT has been under discussion since 1994 when M/s ECC, an ADB consultant, first supported it. Govt. of India constituted a National Task Force in February 1995. It had ten meetings till end 1998 where all the related issues were discussed. A draft notification was prepared for issue by government. With effect from May 15,1999 the jurisdiction was vested in the CERC. Papers were sent to the Commission in June 1999 by the Ministry of Power. The proceedings were held in the Commission from July 26 to 28, 1999. The ABT order dated January 4, 2000 of the Commission departs significantly from the draft notification as also from the prevailing tariff design." We can see that the initial impetus came from outside, and the government took significant time in moving towards ABT.

But still, most stakeholders (like NTPC) did not question the draft guidelines until very late, only by taking CERC to court!

7. Modes of Reform

While Orissa was reform done with privatization, most of the subsequent states, up until Delhi in 2002, reformed with corporatization (unbundling) of the SEBs across segments. Even when different distribution companies were set up, these were on a geographic basis,[57] with no competition for retail customers. Given the nature of the industry, institutionally there are no structural barriers to competition in the generation sector. Gencos already share the market with Central PSUs and IPPs (it is a different matter that the dispatch norms and tariff agreements don't lead to real competition). India appears to be relying on the single buyer model for now (making the role of TransCo special – monopoly seller to DistCos, and monopsony buyer from the GenCos). While there is recognition of the pros and cons of a single-buyer model, the government hopes this is a transitional solution, leading to open access to the wires (Deepak Parekh Expert Committee on State Specific Reforms 2002). Instead of the transmission companies, privatizing the handful of DistCos per state appears to be the thrust of the government. However, a large number of options were considered by the government, as indicated in Figure 7.

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[57] Instead of operational efficiency grounds, many demarcations are being done on financial grounds, i.e., not having any one DistCo with an inordinate number of agricultural (or urban = profitable) consumers.

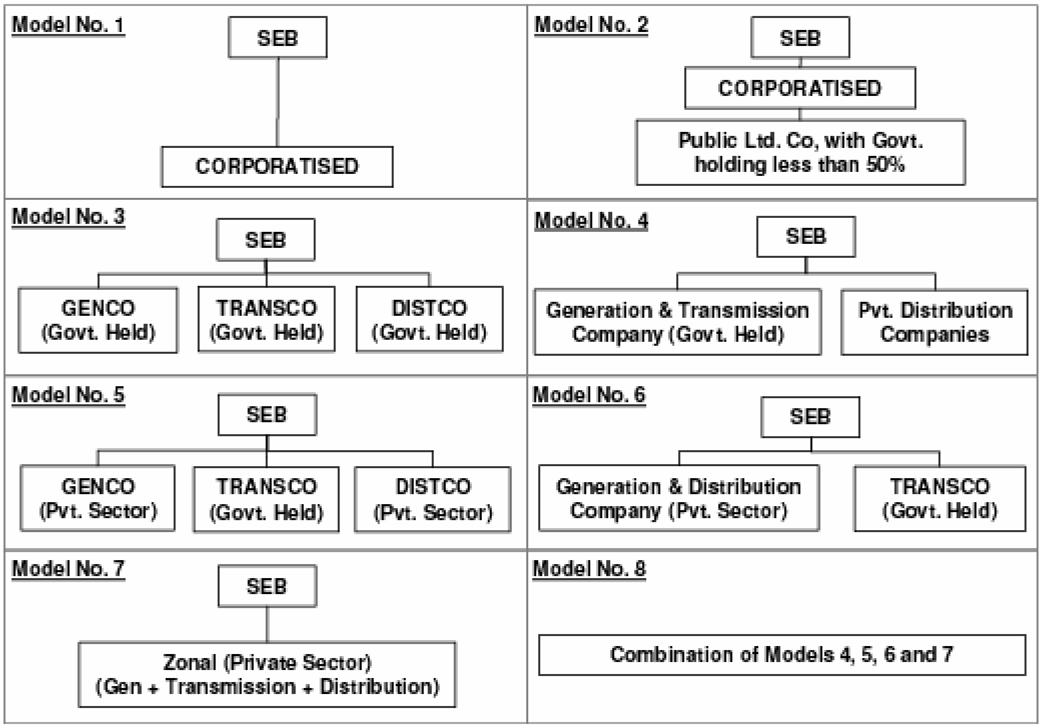

Figure 7: Structures for Reform Considered (Ministry of Power). All of these include external generation, from central PSUs or IPPs.
Source: Distribution Policy Committee Report (2002)

Simply privatizing the already corporatized companies might be one solution, but it leads to several difficulties. What is the valuation for such a process[58]; how are public interests ensured (especially vis-à-vis access and subsidies for particular classes of consumers), and how does this fix the underlying fundamental problem of tariff being much lower than costs? The valuation of the companies is often left to consultants, and it is unclear to what extent the ERCs can comment on this. However, the ERCs (and consumers) are impacted since valuation affects the rate base assumptions for the companies, which helps set the tariffs.

If one looks at the Government 3% RoR stipulation and the current asset base (which might not be the case in the future, both because of a different valuation of assets when sold to private parties as well as the 16% return on *equity* allowed), Table 10 shows to meet the 3% RoR in 2001-02 would require an additional 29,404 crore rupees (294.04

[58] Delhi's recent privatization was different since it was based not on their bids for the assets, but on the reduction in losses the parties promised.

billion rupees). If we divide this number by the total kWh *sold* in 2001-02, 340.061 billion kWh (Table 9), we see that this comes to an increase of about 77 ps/kWh. What is interesting is that this number is less than the gap between cost of supply and tariff, just highlighting the incongruities between the various current accounting mechanisms. If we simply try and back-calculate the asset base assumed in these calculations (knowing the losses post subsidy and the RoR), we find a number around 40-50,000 crore rupees only, which would appear to be extremely low. Even on this base, to hit the 3% RoR, we would have required an additional 1,306 crore of revenue in 2001-02, beyond the gap between "cost of supply" and tariff, coming to about 3.8 ps/kWh. If we consider privatization values, where the valuations have been at least an order of magnitude higher than these book values, *the increase in tariff because of privatization plus profitability might be approximately 40 ps/kWh, if not more!*

One major problem with how the governments have approached the structure for corporatization is shown in the example of Andhra Pradesh (Figure 8). The DistCos report to the TransCo! While some of this because of historical reasons, in that the first step of reforms was separation of a GenCo from a combined TransCo/DistCo, true unbundling would separate the chain of command along more business-like lines. The DistCos, technically, are customers of the TransCo, and thus should follow a commercial (adversarial) role to some extent. TransCo's higher prices mean lower profits for DistCos. Similar skews in powers are often seen in other states, based partially on historical or even personnel reasons. All in all, most states have give more powers and assets to the Transco than might be warranted. In the long run, transmission might simply be reduced to a service operating at costs-plus.

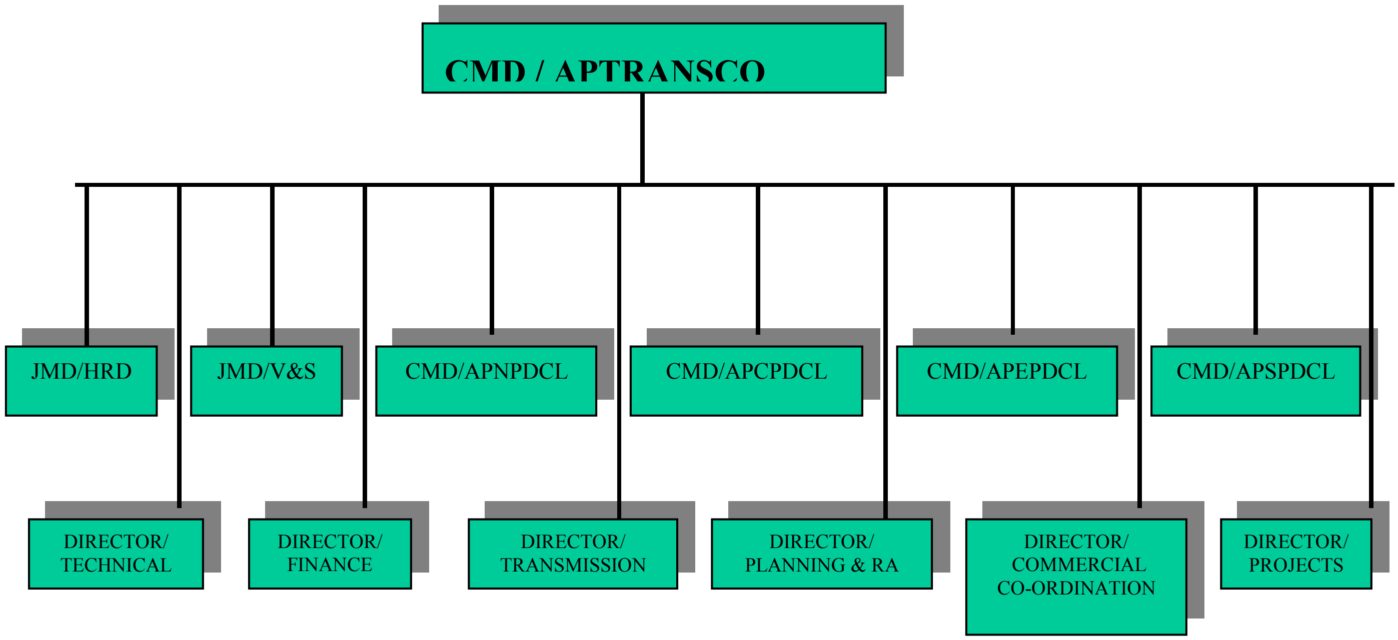

Figure 8: Corporatization structure in Andhra Pradesh (excluding GenCo). We see that the CMDs (Chairman & Managing Director) of the 4 distribution companies report to the TransCo CMD. This is not effective unbundling.

Source: APTransco website (January 2003)

One move has been to open up urban areas for privatization first. Since these are likely to be profitable, there should be strong private interest (and there appears to be). The new entrants coming in are more business-like, not only private sector participants like BSES and Tatas, but even central PSUs, who often look for joint ventures to enter new businesses. NTPC set up a wholly owned subsidiary, NTPC Electric Supply Company Limited (NESCL), in August 2002, with plans to take over distribution in the cities of Kanpur (in Uttar Pradesh) and Gwalior (in Madhya Pradesh). PowerGrid also has plans to provide value-added services in power distribution. Many generation companies we talked to were in favor of getting access to distribution, as a means of bypassing the debt-laden and non-paying utility in the middle.

This solution of linking up the generators and consumers is dramatic, as it reduces the Transco to just a "wires" company. If generators were given a choice, they would only wish to market to particular (high-paying) consumers. If consumers were given a choice, and all generators published their prices, the clearing price would quickly move up since there is limited cheaper generation capacity available. However, the model of giving a distribution zone to a generating company (or subsidiary/joint venture) might be a more equitable solution, ensuring some pooling of costs does occur. It must be remembered in such designs that the range in generator costs is much lower than the range in consumer tariffs today.

However, this dislodges the very foundation of the current system, the paying consumers who cross-subsidize the rest of the system. In addition to privatization of urban areas, the proposed Electricity Bill 2001 would create some of the same issues (through loss of bulk customers to IPPs and captive power with third party sales). If we cherry-pick segments away, what will happen to the rest of the system? Why would a private entity want a large purely rural area for distribution? Even if there is the promise of subsidies to cover losses due to purposeful tariff reductions (like for agriculture), most companies worry about cash flow security. A proposed solution involving "concentrated zones" for privatization states that fears over cherry-picking are unfounded because the cross-subsidies are meant to be temporary, and breaking up the zones would highlight the differences in performance, forcing the state governments to make explicit any subsidy they wish to offer to consumers through budgetary allocations (Deepak Parekh Expert Committee on State Specific Reforms 2002).

In the system today, the bulk supply tariff is sometimes different for the different DistCos, not based on marginal costing issues, but on their ability to pay, customer mix, and current operating parameters. How would such a policy work with privatization? Would these companies continue to see artificially different prices from the TransCo, or would the profitability (and hence valuation) of different DistCos just be different? Valuation of DistCos is also difficult since while the government might want to find the highest value when selling, any purchase via equity will kick in its 16% return on equity tariff implications, increasing costs to consumers. It is unclear to what extent the regulatory commissions can (or should) play a role in valuing DistCos for privatization.

Another issue in such privatization schemes is the *limited number of players with experience*. This was a bottleneck in Delhi's privatization (as well as Orissa's), where only 2 players had serious bids (Tatas, who took one 1 circle, and BSES, who took 2).

Bringing in international partners might help, but they are wary after AES's and Enron's experiences. One solution that has been suggested has been to shrink the size of the distribution circles, to the point that municipalities and new entrants can easily join. However, there are technical trade-offs with such a system. In fact, an extreme example already being seen is the increased used of outsourcing for many responsibilities by distribution utilities. While they see this as a means of lowering costs and reducing staffing, many of these operators lack the technical skills to run a safe, high-quality distribution network. The franchisee ("cablewala") model is one that might provide short-term gains but likely long-term harm. Critics also counter that such a model is expedient since it just passes off responsibilities to other parties.

There are some other issues. When going in for privatization, is it better to attempt to control the losses now, bringing in a better valuation later (hopefully)? This is what Andhra Pradesh is attempting. Or, like Delhi, make that part of the responsibility of the new private DistCo? There is no mechanism for judging whether the big-bang Delhi-like approach is better. Some people believe that a big bang approach is less politically acceptable, but might also lead to better (faster) results. (The counter of Orissa, which went in for privatization early on, doesn't factor in the flawed operational transition and missing support mechanisms.) One issue with big bang approaches is the possibility of spectacular or catastrophic failures, while small, experimental steps can lead to better outcomes through learning. In addition, the ability of the system to absorb or afford big mistakes comes to light (California's flawed steps cost the government billions of dollars, which they could just about afford). However, one has to design smaller experiments well, such that the incentives are correct and the operating system can truly change in relative isolation from the rest of the system. What good does it do a state to reform, be a good citizen in not overdrawing power from the grid, when its neighbors can misbehave, causing grid-wide difficulties, and draw industry to them through non-sustainable tariffs? In addition, there remains the question of how long specific technical fixes would take, steps that facilitate commercially viable operation, e.g., installing meters for agricultural users.

Our discussions with distribution companies and financial institutions indicate that what would really be required to bring in private participation is *regulatory* *consistency and predictability (not just transparency), and a contractual framework for payment of subsidies*. They mention having a tribunal for dispute resolution as also important (addressed in the upcoming Electricity Bill), as the courts are tremendously backlogged. Of course, companies want a streamlining of the approval process, and the Electricity Bill 2001 is supposed to address that. Previous attempts at creating "single windows" for approval did not produce the required results, as different ministries and departments were still required for all the various approvals. Companies also want multi-year tariffs, which reduces their uncertainties, while the SERCs issue Tariff Orders essentially annually. Our studies also indicate that data uncertainty[59] is one of the risks companies face, and they want regular adjustment of some of the bidding (incentive) parameters. Data uncertainty is one of the largest risks private operates face (along with failure to reduce losses), as their performance depends on reducing the losses. Orissa's actual losses turned out to be much higher than claimed before. In the absence of plausible data, many assumptions have to be made. This is an important concern for the entire reforms process, *benchmarking*. Without proper baseline numbers, not only is the private operator at risk, the regulator may be unable to recognize inflated performance improvements.

If one were to consider the Indian system shifting overnight to a market, what would happen? Regulators would need to focus their attention to things they've currently not worried about, like market power. NTPC has some 20% of the capacity of the country, and their role will not go down in the near future. Within the state, the GenCo (or SEB, for now) has the bulk of the generation capacity. A traditional measure of market power like HHI[60] would lead to fairly high amounts of concentration. Of course, the question would remain what size the "market" would be. State, Region, or even National? Financial decisions are taken at a different level (state) than dispatch (regional). Will a (the) market be able to set a fair price for power? Not when you have

[59] There are indications that T&D losses are calculated on plant availability, not factoring in auxiliary consumption (Tables 2.3 and 3.6 of the Planning Commission's 2002 Annual Report on SEB Workings). Repeated attempts at reconciling the numbers has failed. If that were the case, the correct T&D loss calculations would indicate losses higher by around a percent or more!

[60] Herfindahl-Hirschman Index (HHI) is a common measure of market power or concentration in the market. It is equal to the sum of the squares of the shares (%) of the players in the market. It can vary from nearly 0 (full competition) to 10,000.

a system with 15% shortfalls, and where one generator (NTPC) provides a quarter of the total generation.

Comparing India with the England-Wales model can not be done realistically because the starting points and aims were so different. Most western power sector reforms were to bring in efficiency and lower costs. There was already a well-functioning utility (usually regulated and often private). In India, in contrast, the system is not at a stable equilibrium. Simply privatizing the sector without changing some underlying fundamentals (or giving full tariff freedom) will not have the desired effects of improving efficiency, access, and penetration, while lowering costs simultaneously.

There are many options available, and this chapter can not be exhaustive in its scope. Nonetheless, increased analysis and debate regarding upcoming legislation (as opposed to regulatory commission orders) might be useful. The Electricity Bill 2001 is quite sweeping, and not all of its points might be helpful to the power sector, or certain segments. India often does the opposite of analysis paralysis, whereby major policy directives come about without much thought to implementation.[61] Not only Bills and Acts, but operational decisions, e.g., to meter all distribution transformers,[62] to use IT for remote metering, pre-paid billing etc., must be examined in more detail. The costs involved and implications are enormous, and pumpset metering history has shown us undoing one policy can be nearly impossible.

It is clear that regardless of what exact form of restructuring is chosen, it will involve participation from all the stakeholders. A non-integrated approach, akin to partial reforms, might be unsuccessful. One suggested strategy for redoing the financials for successful reform is presented below through mitigation mechanisms (Deepak Parekh Expert Committee on State Specific Reforms 2002):

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[61] A classic example is the (Supreme Court) directive to convert commercial vehicles like taxis in Delhi into compressed natural gas (CNG) in the late nineties. This decision was taken so rapidly that for some time there were only a handful of CNG pumping stations set up, causing lines for CNG that would often last 4-6 hours, or more.

[62] Some SERCs mandate Distribution Transformer (DTR) metering as a stop-gap until meters on pumpsets can be put in. These should also be electronic meters, and give time of use information with over 1 month of data stored in memory. However, such a meter would allow only historical (billing-centric) data, and not allow real-time or operating control, a limitation of such a technology-based standard, instead of a performance-based standard.

Table 16: Strategies for mitigating financial deficits

Stakeholder	Past Deficits	Future Deficits
• State Government	• Take over past liabilities and write off dues to itself	• Expedite Privatization • Pay its bills • Assure Subsidy Support • Provide Law and Order Support
• Utility	• Collection of receivables	• Aggressive Pursuit of Efficiency
• Creditors and Suppliers	• Write-down of old dues	• Limiting future supply prices
• Financial Institutions	• Restructuring of loans	• Reform-linked financing
• Regulatory Commissions	• Agree to a surcharge to service past liabilities	• Institute an incentive driven Multi-year Regulatory Regime
• Consumers	• Agree to a surcharge to service past liabilities	• Accept Tariffs based on benchmark (in)efficiency levels
• Central Government	• Re-financing past liabilities at concessional rates	• Extend reform-linked grant support and Limiting future supply prices from CPSUs

Source: Expert Committee on State Specific Reforms (2002)

Fundamentals (Or, What gets left behind)

What the reforms have not done is fix the basic problem of finding an equilibrium that is viable. Generator prices are somewhat capped (despite occasional aberrations), and the current costs-plus mechanisms or eventual markets will lead to a certain price range for power, likely between 2 – 2.5 Rupees/kWh in today's terms.[63] What can be charged from consumers is somewhat limited, both politically, and by the regulators (who especially are limiting how much cross-subsidy – overcharging – can be burdened on paying commercial and industrial consumers). Thus, the reforms fail to bring about a solution to the question of who best should bear the losses and risks in the system. What is a harder question to pose and answer is do the reforms set up the system so that it can evolve to find the right equilibrium? Or, is it pre-determining some modes of success and failure, e.g., generators can be assured of higher returns than distribution and/or transmission companies?

What unbundling will help fix is the flawed accounting measured followed by utilities, whereby their internal generation and T&D costs have been pooled, distorting the finances. "Power purchased" became a line item expenditure (Table 17), but the T&D calculations were taken lumping all losses at the state level. This is why the average purchase price, even with with IPPs, looks much lower than the "average cost of supply" number of the SEBs, as the latter includes all the losses (at the in-state level) and more operating costs. As the SEBs unbundled, and truer unbundled costs were seen in part, the Generation Companies in the states that had them provided lower power than outside sources (2000-01). Unbundling will also correct the flawed calculations by states today that end up comparing total costs of outside generators with only the operating costs of their own generation (as they view their generator assets as sunk costs). On a purely operating (variable) basis, central and even IPP plants are often cheaper than SEB generation stations.

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[63] These prices are a little high compared to US estimates for new generation, estimated at around Rs. 1.8/kWh at today's exchange rates, even with higher environmental standards. Some of the difference can be attributed to policy and Indian conditions, e.g., import duties, high cost of capital, etc.

Table 17: Cost of Supply breakdown

(ps/kWh)	Fuel	Power purchase	O&M	Estt. & Admin.	Misc	Depreciation	Interest	Total
1997-98 (Actuals)	55.26	87.2	9.84	32.6	5.22	18.53	31.09	239.73
1998-99 (Actuals)	52.8	101.96	9.4	38.37	6.33	18.67	35.52	263.05
1999-2000 (Provisional)	46.29	149.23	8.63	40.48	9.12	19.98	31.39	305.12
2000-01 (RE)	46.34	165.16	8.91	44.24	7.91	19.74	34.86	327.16
2001-02 (AP)	45.84	185.05	9.1	44.4	6.35	21.08	38.03	349.85

Source: Planning Commission (2002)

Doing some quick sanity check calculations, if we have the model as shown in Figure 9, we can suppose the following numbers. If the generator costs are 2.2 Rs./kWh (which is an average number),[64] there would be losses of about 2% getting to the TransCo (conservative, based on Indian voltages and runs). The Transco would add its costs plus returns, perhaps 10%. Actual Transco costs are usually higher today, as approved by the ERCs, but there is no reason Transmission should cause a mark-up of 25+%. This 10% appears to be a future target (bound). There are then transmission losses going to the Distco, another 6% (allowed losses as per ERCs are often higher). Then, the DistCo has operating costs, which are higher than for the TransCo, which we take to be at least 25%, especially when we factor in private operators who take their allowed 16% return on equity. Lastly, there are losses going from the Distco to the consumer, as well as theft. These would, as a lower bound, be taken as 7% and 5%, respectively (zero theft is a long ways away!). Then, our future system would go from 2.20 Rs./kWh at the generator to 2.63 at the Transco (which is very aggressive – Andhra Pradesh goes from about 1.8 Generator prices today to about 2.3 average bulk supply tariff, charging over 2.5 to some DistCos), to 3.74 Rs./kWh for the consumer. This is after the total losses come down to 20%, including theft, and costs for TransCo and DistCos are controlled. In comparison, today's average cost of supply is calculated to be Rs. 3.50/kWh, which uses historical

[64] US and other countries see generator costs that are often lower, but vary significantly. Perhaps not having varying supply costs forces a higher average (loss of microeconomic efficiency).

(cheaper) average generation costs and doesn't have profitable private utilities (but has high losses).

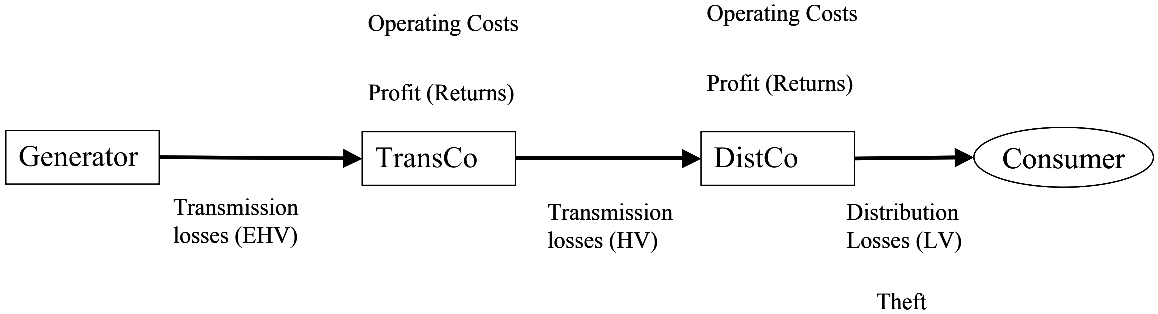

Figure 9: Generalized (unbundled) costing model

While the exact numbers might vary, such a breakdown is useful as it lets us compare the costs of the different portions of the network, e.g., T vs. D vs. Generation. US numbers indicate that T should be only about 5% of total costs, and Generation a little over one half. If we look at the cost to the consumer, using today's exchange rate, this Indian number calculated above comes to 7.78 cents/kWh! EIA data indicate that the US average retail tariff in 1999 (excluding only end-user taxes) was 6.66 cents/kWh, with industry paying 4.43 c/kWh, residential 8.16 c/kWh, and commercial 7.26 c/kWh. Even when adding taxes, and recognizing that the US price has not increased much in the last few years, we see that *electricity in India will be more expensive than the US, more so if loss reduction and cost control aren't achieved*! This indicates that company costs must be controlled even further, generator costs must be reduced, and theft must be brought down to near zero, if India wants its power system to be competitive and viable.

How much will today's skewed tariffs continue? Some people have argued that hydropower is a cheap, national resource (historical hydro costs are very low, since the capital is largely amortized). Its output could be dedicated for specific classes of consumers, like agriculture, keeping their cost low. This concept is generalized into ranking and correlating (or even dedicating) output from cheapest sources to certain consumers (Sankar 2002). However, this view is incorrect on a number of grounds. For starters, it sends incorrect signals to the consumers, voiding economic efficiency at a system level. Secondly, it ignores opportunity costs. In a market, if there were such a thing, why would a hydro (or any) unit ever sell at marginal cost all the time (even if its capital expenditure has already been amortized)? In a well-functioning market, whether one's costs are amortized or not doesn't affect prices. A market, more so when competitive, would see a range of prices, going down to marginal cost for some periods of time. The last problem with the "cheap generation for some users" approach is typical of many SEB/utility calculations, in that it looks only at the average, and not at the margin (forget short-run vs. long-run). Where is the new hydro capacity coming up? Even if so, what are its costs? If we look at incremental consumption, from any category, it has to come from incremental generation, which is much more expensive than the average cost, which essentially sees pooled costs.

Sectoral variations and consumption

If one looks at where agricultural consumption fits in, Planning Commission estimates state that there are 13 million pumpsets today, out of a potential of over 19.5 million. If one extrapolates to the future, when the population might stabilize at 30% higher, where crop patterns change to more water intensive (e.g., cash) crops, and where the water table is lower, then the total absolute demand might be double today's. In addition, if power is made available 24 hours, the demand will increase somewhat (up to the limit of waterlogging the fields—no one knows how much demand would increase, and it is a function of the price, as well). At the same time, if one converts to more efficient pumpsets and sizes the pumpsets and bore size optimally, then the power consumption could be reduced by 30-60% percent, if not more. In the long run, the relative share of agriculture should have reduced, helping the system approach viability. The main difficulty remains the transition to such an economically viable future.

There have been attempts at providing power to agriculture at least at average long run marginal cost, in return for assured quality and timings. While the results have been positive, extending such limited trials across the country will remain a Herculean task.

The other end of the spectrum relates to commercial and industrial consumers. Their tariffs are already very high (some users will pay over Rs 7/kWh in Andhra

Pradesh). This hurts industry significantly, and SERCs are limiting increases on these classes of consumers. In addition, captive power provides a significant backstop in terms of prices, and the 2001 Bill, when passed, will only exacerbate the situation, with open access rules. In the interim, some SERCs are limiting captive power, essentially siding with the utilities who fear this hurts their financials significantly.

In addition to the fundamentals, the reforms process does not address several issues head on, namely *fairness* and *access*. Today's supply of power is inadequate, and there are frequent black-outs, brown-outs, and rostering of power. Agriculture, in particular, sees limited supply. Most states have a policy to first provide power to domestic users, and then commercial/industrial, then agriculture. However, sometimes agriculture takes priority over some segments, especially when politically important. Is there a fair, transparent policy for making decisions on triage of power? How does this tie in to economic calculations? Of course, commercial/industrial users complain they must unfairly cross-subsidize other consumers, which is a fact.

What rights do consumers have in terms of quality of power? They already pay an enormous implicit cost for power quality through the near universal use of voltage stabilizers and/or uninterrupted power supplies for electronic equipment causing not only capital expenditure, but upto several percent higher consumption due to losses). What recourse do consumers have when quality of power causes damage to equipment? Many SERCs provide consumer rights information to consumers, supplemental to the Consumer Protection Act, and the Supreme Court ruled that consumers could directly address regulatory commissions. However, consumer protection has remained a weak link in providing customer service because of limits in the resources SERCs can devote to individual complaints.

While there is a policy towards providing electricity for all by 2012, how will this be financed? Should there be the equivalent of a Universal Service Obligation fund (like in telecom) for increasing access? The World Bank says to meter all the consumers, and make the "haves" pay for electricity. However, how can means based testing be done, given only 2% of Indians pay income taxes? How can electricity be made affordable for consumers? Perhaps the long-term answer of overall economic growth, like seen in China, is the only answer.

Other issues with the reforms include their limited focus on technology and operational improvements, e.g., upgrading transmission voltages, valuing ancillary services beyond raw kilowatt-hours (like reactive power,[65] frequency control, grid support, spinning reserves, etc.), and R&D for better operations. Institutionally, R&D is something lagging in the Indian power sector, but the same can be said for India as a whole. While some larger Central PSUs and departments have world-class R&D, notable in nuclear power and Bharat Heavy Electricals Limited (BHEL – an equipment supplier), most utilities themselves have near zero R&D. This also limits innovation in terms of equipment deployed, especially in the distribution segment. Most equipment comes from tenders, which are very static in their performance demands. While there is an autonomous government body, the Central Power Research Institute (CPRI) for power sector research, its funding limits it to specific research projects. There is no utility-based membership body like the US Electric Power Research Institute (EPRI) for doing research that is in the interests of the utilities. No Indian utility is a member of EPRI, citing prohibitive membership costs. One other source of technical skills that is underutilized is academics within the country (and outside). Not only are academics less expensive than consultants, they usually provide impartial and balanced views, with less conflicts of interest. (This is an issue for not only the power sector, but overall, within Indian policy-making.) Similarly, there is limited utilization of international hands-on and operating experience in many aspects of power sector development (not specifically reform). While many trips abroad are taken (? junkets), these are often one-off undertakings. There are recent moves to build up relationships for learning about experiences with rural electrification, for which groups like National Rural Electrification Co-operative Association (NRECA), USA, have expressed support. Power officials cite Bangladesh as another example to learn from, but the mechanisms for such are not yet developed.

[65] Inadequately addressed in the recent Indian Electricity Grid Code (2002).

There is also very little discussion over the environmental impacts of reforms. While critics have complained about IPP projects on environmental grounds, it is a fact that modern plant are better designed and have lower emissions than vintage plants. However, a greater impact might come from fuel choices and overall growth of generation, especially coal power. While the reforms encourage conservation and demand side management, it is not clear what additional incentive structures might be needed to spur along such moves, as well as higher efficiency standards. The link between prices, generator, and distribution company is also unclear on how it will promote DSM. Today, distribution companies have no incentive to reduce power they sell to industry/commercial users, and the PLF model of pricing supply gives no incentive for reducing generation. Newer tariff models like ABT that provide for deemed generation reduce perverse incentives to over generate, but do not provide incentives to reduce generation beyond the contracted amount.

Mindset and change

One hurdle to the reforms process has been the government has often not been able to relinquish operational control, even when they retain only some ownership stake. This was the case with the disinvestments of the telecom PSU, VSNL, to Tata, where the government loudly criticized decisions taken by the Tata-controlled board in 2002 (Srinivasan 2002). This is still very much true, where corporatization has led to some changes on people's mindset, but these are still very much government entities. Electricity is still thought of in terms of the social function, and thus the responsibility of the government. Similarly, there is an implicit calculation that prefers domestic fuels to imported fuels, citing energy security and self-reliance. The last mindset that needs change is that of personnel.

Labor

The multitude of staff in the SEBs, built up over decades, view(ed) their government jobs as jobs for life, and government jobs have had especially poor performance accountability. This is in a regime where labor laws in general are viewed as anti-business, and calls for reform have been growing louder over time, especially from a private (foreign) investment perspective. The government has attempted to introduce some labor reform, especially when it comes to hiring and firing (and associated compensation), use of contracted labor, etc., but political resistance has limited such reform. The problems are legislative, with labor falling under the concurrent list of the constitution. There are 47 federal laws and more than 170 state statutes dealing directly with labor. Many rules are actually over a century old, but still in force, and many decisions fall back to the Industrial Disputes Act of 1947, which, for example, requires government permission before companies above a certain size can lay off employees or close down plants, and such permission is virtually never given (Rao 2000). Fundamental labor reform will be required to improve India's productivity, not just in the power sector.

Labor productivity is quite low in India, measured in terms of revenues (or even kWh) per employee. While improving from an all-India average of 4.6 employees per million kWh in 1992-93 to 2.82 in 2000-01 (Revised Estimate) (Planning Commission 2002), this is still well below global norms, regularly below 0.5 employees per MkWh. The state of Uttar Pradesh had over 120,000 employees a decade ago, and this number came down to 90,000 and now 70,000. However, this is for a capacity not much more than that of Connecticut, which has only a few thousand employees in the utilities!

As reforms were announced, there were often strikes by utility employees against such moves. The compromise reached was often to guarantee job security for the employees, something that extends even beyond corporatization to privatization. When BSES took over 2 of Delhi's distribution circles in 2002, it acquired 1.6 million customers and 13,000 employees. In comparison, in Mumbai, where they were a private operator from the start, they have 2.2 million customers and 4,500 employees (approximate numbers as per personal communication). Such deals hamper the benefits of privatization, as they limit not only efficiency and productivity growth, they reduce the ability of the DistCos to innovate, introduce new technology, and bring in a new work culture.

Labor has also been cited as a reason for rampant theft, often done in connivance with utility employees. There is now legislation enacted (state-wise as of now) that makes such employees subject to harsh punishment. In addition to power theft, there is often collusion in tendering for contracts and parts. While government watchdog bodies (like the Central Vigilance Commission, Controller Auditor General, etc.) attempt to rein such practices in, this remains difficult. Privatization could help change such practices, which will also have implications in terms of technology choices and quality. Most government entities tender for contracts (while not necessarily the best method, it is one that offers the greatest *image* of propriety). Such methods don't favor innovation or new technologies, which often find first adoption in private companies.

While some analysis has been done on labor, overstaffing, productivity, etc., in the power sector, not as much discussion has taken place on senior management. These are often IAS officers, or other civil servants, instead of career power professionals, and this sometimes creates resentment in the ranks. Their commitment and talents aside (the selection process is exceptionally arduous), short term appointments make it difficult for them to take long term actions when not only will they not receive the credit, their work can be undone very easily by the next person there who might have different views on the subject. There are attempts to improve on this, but these have been primarily due to personal intervention by those in-charge (the Ministries/executive branch), and not due to systematic changes. At the end of the day, <u>successful reforms depend on strong will and execution by senior utility and regulatory commission officials, coupled with the political leaders having the resolve to make tough decisions, while balancing the conflicting demands of different stakeholders.</u>

8. Conclusions

India's power sector is undergoing broad reforms, not only unbundling the previously vertically integrated monopolies (the State Electricity Boards) and opening up the sector to competition, it is also moving towards a significantly reduced role of the government. The roles that remain will be of regulator, stakeholder, and financer (especially for rural electrification), but not operator. The drivers for the reforms have been such a significant deterioration in SEB finances and operating parameters that there is a political will to do whatever it takes to fix the problem. Part of this was a tacit acceptance of the poor power situation as a failure of governance.

The initial reforms (1991 onwards) focused on generation (and private players), but this did not lead to any significant increase in capacity. Since the mid 1990s, reforms have been focused on structural changes in the system, with the establishment of independent regulators, and unbundling of the SEBs. There is a current thrust on improving distribution systems, reducing the high technical and commercial (theft) losses that take away some 30% of net generated power in the country. Equally importantly, there is an attempt at tariff rationalization, without which the long term viability of the system will be suspect.

As India is a diverse nation, and different states move ahead differently, and at varying speeds. Some general trends that can be seen are:

- Establishment of an independent Electricity Regulatory Commission
- Attempts to rationalize tariffs
- Directives to lower losses (especially theft)
- Moves towards unbundling the system, with privatization of distribution a possible goal
- Eventual moves towards a power market, driven by national legislation instead of state initiatives.

It is too early to tell how successful the reforms have been, and they can best be described as necessary but not sufficient steps. In the last few years, the T&D losses have stabilized somewhat, but there is only limited interest of private players into the sector, especially new players. Those who state that overall financial losses have increased after the reforms do not factor in the increase in costs due to generator price increases regardless of reforms, even from government generators and PSUs.

The next five years will likely be critical when determining the health of the power system, especially with the passage of dramatic legislation like the Electricity Bill 2001, which opens up the sector to private participation with limited approval obligations. This sector is vital to India's growth and development, and reforms have addressed several of the shortcomings like efficiency, losses, etc. At the same time they have not sufficiently addressed structural changes for grid operation and discipline (dispatch), such as based on load duration curves, or access and penetration for the poor (especially how that affects financial performance). Nonetheless, they are a step in the right direction, ending years of government control and mindset. We do not suppose, *a priori,* that government corporations will perform worse than private companies, but having all of them competing to perform better will only help the consumer and the sector as a whole.

Appendix – Abbreviations

ABT	Availability Based Tariff
AP	Annual Plan (or the state of Andhra Pradesh)
ARR	Annual Revenue Requirement
BHEL	Bharat Heavy Electricals Limited
BJP	Bharatiya Janata Party (Ruling party in the present Indian Government – in a coalition)
CCGT	Combined cycle gas turbine
CERC	Central Electricity Regulatory Commission
CM	Chief Minister
Crore (or cr.)	10,000,000 (4.8 crore rupees ≈ 1 million US$ today)
DFID	Department for International Development (UK)
DPC	Dabhol Power Company
DSM	Demand Side Management
DVB	Delhi Vidyut Board
EPRI	Electric Power Research Institute (US)
ERC	Electricity Regulatory Commission (Includes variants like CERC, SERC, OERC, etc.)
GoI	Govt. of India
IAS	Indian Administrative Services
IPP	Independent Power Producer
kWh	Kilowatt-hour
MIS	Management of Information Systems
MoU	Memorandum of Understanding
MW	Megawatt
NTPC	National Thermal Power Corporation
PLF	Plant Load Factor
PPA	Power Purchase Agreement
ps/kWh	Paise per kilowatt-hour (100 paise = 1 Rupee)
PSU	Public Sector Unit
RE	Revised Estimate
RLDC	Regional Load Dispatch Center
RoE	Return on Equity
RoR	Rate of Return
Rs.	Rupees
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
T&D	Transmission and Distribution
WB	World Bank
WB-SAR	World Bank - Staff Appraisal Report

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