

Sustaining India's Growth Miracle

EDITED BY
JAGDISH N. BHAGWATI AND
CHARLES W. CALOMIRIS
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 **Columbia Business School**
Publishing

CHAPTER 3

Reforming the Indian Electricity Supply Industry

Frank A. Wolak

1. INTRODUCTION

More than fifteen years of experience with electricity-industry restructuring in both industrialized and developing countries has demonstrated that success is extremely elusive. Even countries now offered as examples of successful restructuring processes have required significant regulatory intervention at some point during their development. The England and Wales electricity supply industry required several rounds of forced divestitures of generation capacity from the two dominant firms, and the original electricity-pool market design was abandoned and the New Electricity Trading Arrangements (NETA) implemented in early 2001. The Chilean electricity industry experienced shortages that required electricity curtailments for up to three hours per day from late 1998 until the middle of 1999. In response, a number of changes in the legal framework governing the operation of the Chilean electricity supply industry were implemented.¹

Inadequate regulatory oversight has contributed to many of the recent wholesale electricity market failures. The California electricity crisis was due in large part to the failure of the Federal Energy Regulatory Commission (FERC), the United States wholesale market regulator, to enforce the Federal Power Act of 1930 during the summer of 2000. FERC's misguided attempt to implement "remedies" during late 2000 allowed a solvable problem to develop into a full-fledged financial crisis.² New Zealand experienced two sustained periods of extremely high spot prices during June to September of both 2001 and 2003. Immediately following the second event, the New Zealand government abandoned its "light-handed" approach to regulating the industry and formed a seven-member Electricity Commission to take over the governance functions for the market.

These successes and failures emphasize the essential role of a forward-looking regulatory process to intervene to correct market design flaws before they cause significant harm to consumers. Few developing countries have any experience with regulatory oversight before embarking on a restructuring program. Consequently, a major challenge to successful electricity industry restructuring is establishing a regulatory process that protects consumers from significant harm yet allows suppliers and retailers the opportunity to earn sufficient revenues to recover their production costs, including a reasonable return on their investment.

Many of the current problems in India's electricity supply industry are the direct result of an ineffective regulatory process. Only roughly 55 percent of electricity produced in India is billed, and slightly more than 40 percent is regularly paid for (DOE 2003). A large fraction of this shortfall is due to theft, what is often referred to as commercial or nontechnical line losses. For 2000–1, the average tariffs for the State Electricity Boards (SEBs) were set to recover less than 70 percent of the average cost of supplying electricity (Report of Expert Group 2001, p. 51). In many states, agricultural users are charged a small fraction of the cost of producing the electricity they consume, less than 1 cent per kWh (Dhume 1999). Attempts to raise these prices have been met with enormous political resistance.

Foreign investors have also shared the cost of this ineffective regulatory process. There are a number of examples of SEBs paying significantly less than the contract price to foreign investors for electricity produced from new generating facilities that these investors built under long-term supply contracts (Slater, 2003). Enron's \$2.9 billion Dabhol plant is the best-known example of this phenomenon.

As the experiences of California and New Zealand demonstrate, short-term wholesale electricity markets can put enormous stress on the regulatory oversight process. Therefore, it is prudent for India to establish credible regulatory processes at both the state and federal levels before moving forward with further wholesale market restructuring. Besides limiting the risk of a wholesale market meltdown, this strategy has the potential to yield substantial short-term benefits without compromising the potential long-term benefits of establishing a national wholesale electricity market in India.

I first outline the initial conditions in the Indian electricity supply industry that argue in favor of establishing effective and credible regulatory processes at the state and federal levels before moving forward with further restructuring. I then describe the necessary conditions for an effective regulatory process and provide several recommendations for increasing the

credibility of this regulatory process. I then summarize recent progress that has been made toward achieving this goal, particularly improvements that resulted from the Electricity Act of 2003. Finally, I propose a transition process for introducing wholesale competition in India, different from that proposed in the Electricity Act of 2003, which limits the stress that may be placed on state and federal regulatory processes.

My analysis of the current situation in the Indian electricity supply industry demonstrates that the potential benefits to the Indian economy from establishing an effective regulatory process swamp the short-term and medium-term benefits of introducing a competitive wholesale electricity market. The majority of the benefits from wholesale electricity competition can be captured without introducing many features that have led to the problems experienced in industrialized countries around the world. For example, Wolak (2003b) notes that the experience of many Latin American countries demonstrates that significant benefits from electricity industry restructuring can be captured without a bid-based spot market. Virtually all of the wholesale markets in Latin America use a cost-based spot market to maintain real-time system balance. The Latin American experience with electricity industry restructuring provides valuable lessons for designing a restructuring process for India that captures all sources of benefits that exceed their expected costs of implementation.

2. THE NEED FOR EFFECTIVE REGULATION IN THE INDIAN ELECTRICITY SUPPLY INDUSTRY

Initial conditions in the Indian electricity supply industry are not conducive to a successful restructuring process. In fact, it is difficult to imagine more adverse initial conditions. Tariffs are set significantly below the average cost of supplying power for all customer classes. This is particularly the case for agricultural users. Technical line losses are among the highest in world and theft of power is rampant. Consumption is unmetered for many agricultural users and is instead based on the water pump's horsepower rating, which encourages overuse and can allow theft to occur more easily (Dossani 2004). The transmission network has limited transfer capacity across regions of the country, which can often leave significant excess generation capacity in some parts of country that cannot be used to meet demand in other parts of the country (Lama and Kemal 2003). Private sector participation by foreign and domestic firms has declined substantially because of the much-publicized difficulties the SEBs have in fulfilling

their payment obligations under long-term power purchase agreements. Recent statistics issued by the Ministry of Power demonstrate that all but 70 MW of approximately 5,700 MW of non-captive new generation capacity brought on line during 2004–5 is owned by the central government or a state government (Central Electricity Authority 2006, p. 57).

Commercial losses to the Indian electricity supply industry during 2001–2 were estimated to be equivalent to 1.5 percent of India's Gross Domestic Product (Report of Task Force 2004, p. 47). According to the Ministry of Power, total subsidies for 2004–5, the latest year of data currently available, are roughly 25% lower than total subsidies for 2001–2. The rapid growth of the Indian economy has now made these subsidies slightly less than 1 percent of India's GDP. Although the financial conditions of several SEBs have improved in recent years, all but a few SEBs continue to post negative rates of return because retail tariffs are set below the average cost of supplying electricity and technical and commercial transmission and distribution losses continue to grow.

2.1 WHOLESALE COMPETITION VERSUS RATIONAL RETAIL MARKET POLICIES

The consensus view among academic observers is that the major source of benefits from introducing wholesale electricity competition is cost reduction that results from more efficient new capacity investment decisions.³ During the former state-owned monopoly regime or privately owned geographic monopoly regime, these firms often pursued other objectives besides finding the least-cost technology necessary to meet a demand increase. The benefits associated with a more efficient dispatch of generation capacity because of competition to serve demand have turned out to be significantly smaller than was initially expected because of problems with the exercise of unilateral market power in the spot market.⁴ In addition, it has turned out to be a significantly more difficult regulatory challenge to encourage active demand-side participation in the spot market, which has further enhanced the ability of suppliers to exercise unilateral market power in the spot market, and thereby limit the short-term gains associated with introducing a wholesale market.

Although it is extremely difficult to quantify the potential long-term gains associated with the formation of a wholesale electricity market, even the most aggressive, but plausible, estimate is that average retail electricity prices would fall by 5 percent. Because wholesale electricity prices account for slightly more than 50 percent of the retail price of electricity, this

retail price reduction would require a fall in wholesale prices of approximately 10 percent.

The United Kingdom market is representative of the amount of time it might take to realize this price reduction. The restructuring process in England and Wales began in 1990, but it was almost ten years before tangible reductions in average wholesale electricity prices occurred as a result of substantial new entry and greater competition from existing capacity now owned by a substantially larger number of independent suppliers following several rounds of divestitures.

Considering the potential benefits of a competitive wholesale market and the amount of time necessary to realize these gains, the enormous costs associated with the existing electricity supply industry in India clearly demonstrate that introducing a competitive wholesale market in India should be a low priority. Eliminating the subsidies to electricity has the potential both to eliminate a significant burden on government revenues and to encourage more efficient electricity consumption decisions. The benefits from introducing wholesale electricity competition are, at best, a very small fraction of the benefits to the Indian economy from eliminating these subsidies and are likely to take at least ten years to realize. Consequently, the policy with the greatest expected benefits to the Indian economy is, by far, one that focuses on eliminating subsidies to the electricity supply industry as soon as possible.

The expected benefits to Indian consumers from this policy may be especially large because the existing subsidies to electricity consumption introduce a number of other costs. By artificially increasing both the demand for electricity and the growth in demand, these subsidies create secondary market harm in the form of overconsumption of groundwater by farmers because electricity used to pump groundwater typically has a zero marginal price. Charging farmers prices that reflect the cost of producing the electricity they consume for each kWh they consume would reduce the harm associated with overconsumption of groundwater.

Eliminating this enormous subsidy to electricity consumption would have the additional benefit of reducing the need to finance new generating facilities. A recent study by Filippini and Parchuari (2004) of the demand for electricity by urban Indian households, finds own-price elasticities for household electricity demand that are larger than those obtained for industrialized countries, although they are still less than one in absolute value. This study finds that for urban households, increasing the price of electricity by 10 percent should reduce the demand for electricity by approximately 5 percent. This study also found a positive income elasticity of

demand, so that as household incomes increase, the demand for electricity should also increase. Moreover, if the Indian government's target of sustained GDP growth of 8 percent per year or more is realized, electricity demand should continue to increase, even at higher prices that contain no subsidies.

By reducing the rate of growth in demand for new generation capacity in the short-term as a result of the elimination of subsidies to electricity consumption, more scarce public funds could be devoted to investments in new transmission capacity to increase the interconnection capacity across regions of the country. This would allow the existing generation capacity to be used more efficiently by reducing the number of hours of the year when unused generation capacity cannot produce energy to be sold in neighboring regions because of insufficient transmission capacity.

Reducing the level of subsidies would also free up much-needed public funds to install meters and other technology necessary to measure final consumption. Setting a zero marginal price for electricity because of the lack metering technology imposes significant environmental damage. For the year 2004–5, 71.37 percent of India's electricity came from coal-fired generation facilities, 14.23 percent from hydroelectric facilities, 10.35 percent from natural gas-fired facilities, and the remainder from diesel, nuclear, wind, and other renewable energy sources (Central Electricity Authority 2006, p. 67). This technology mix implies that coal, a major contributor to greenhouse gas emissions, is the highest variable cost technology providing energy during many hours of the year. During the hours when coal is not the highest variable cost technology operating, other fossil fuel technologies are, such as diesel or natural gas-fired combustion turbines. This logic implies that the marginal private cost of producing an additional kWh of electricity is never close to zero (DOE 2003). Including the cost of greenhouse gas emissions in this calculation further increases the cost of an additional kWh. Pricing wholesale electricity closer to its marginal private cost of production would have significant environmental benefits in the form of reduced greenhouse gas emissions.

2.2 EXTENT OF FOREIGN PARTICIPATION IN THE INDIAN ELECTRICITY SECTOR

According to the Indian government, all of the SEBs are technically bankrupt, with cumulative losses totaling more than 220 billion rupees in 2004–5, down from 290 billion rupees in 2001–2.⁵ Due to these financial

difficulties and the failure of the SEBs to honor fully their payment obligations to investors, a large number of foreign-sponsored generation projects have been cancelled or delayed, and very few new projects have been initiated. According to the U.S. Energy Information Administration (EIA 2003):

The \$5 billion, 3,960-MW coal-fired Hirma Power Plant, was canceled by [Mirant Corporation](#) in December 2001.

Electricite de France has quit the coal-fired 1072-MW Bhadrawati project in Maharashtra state.

The 1,886-MW LNG-fired unit at Ennore, with an associated LNG import terminal, was canceled by CMS Energy in June 2001. CMS Energy also announced in October 2001 that it was pulling out of several smaller projects.

India's National Thermal Power Company was planning a 2,000-MW LNG-fired plant at Pipavav, but the project was shelved in June 2001.

Powergrid was planning a 1,320-MW coal-fired plant for Cuddalore, which was delayed indefinitely in early 2001.

Cogentrix cancelled the 1,000-MW Mangalore coal-fired project in December 1999.

South Korea's Daewoo Power and ABB Lummus cancelled plans for a 1,400-MW plant in Madhya Pradesh in August 2000.

According to the EIA, no major foreign-owned projects were launched during 2003. As noted earlier, only 70 MW of non-captive privately owned generation capacity came on line during 2004–5. The vast majority of privately owned generation capacity that has come on line over the past three years is captive generation capacity built to serve a nearby industrial facility. These captive generation facilities can, in most instances, sell surplus power to the bulk transmission grid. However, their financial viability depends on sales to captive customers.

The current financial condition of the SEBs and the financial condition of the international generation sector make further foreign investment in India for non-captive electricity needs extremely unlikely without significant progress toward improving the financial condition of the SEBs. This logic strengthens the argument in favor of delaying further restructuring of the Indian electricity supply industry and first developing an

effective and credible regulatory process that charges prices that recover the total cost of producing electricity, including a return on the capital invested.

Immediate elimination of the enormous subsidies to agricultural users and smaller subsidies to residential users is politically impossible, but putting in place a regulatory structure to begin the process of reducing these subsidies to large customers in three to five years is feasible. That would also allow enough time to attract new foreign investment once the international generation sector recovers its financial footing. Although subsidies to some customers may remain, those subsidies should be means-tested and subject to maximum consumption levels. Section 5, below, discusses the current state of progress toward the goal of financial viability of the SEBs.

3. ESTABLISHING EFFECTIVE FEDERAL AND STATE REGULATORY PROCESSES

Foreign investors are unlikely to return to India unless they believe that long-term supply contracts signed to finance new generation facilities will be paid in full. Retail tariffs that recover the average cost of supplying electricity are an essential first-step toward increasing investor confidence in the industry. Unless the central government guarantees the revenue stream of all long-term supply contracts signed by SEBs with private investors, retail tariffs that cover the average cost of supplying electricity to final consumers are a necessary condition for private investors to enter into long-term supply contracts with the SEBs. Reducing the number of unmetered customers, technical line losses, and the amount of theft of power are all parts of an effective regulatory process. These actions would demonstrate a commitment on the part of the government to collect sufficient revenues from customers to pay for the electricity produced.

The Indian government already has a legal foundation for implementing effective and credible regulatory oversight through The Electricity Regulation Act of 1998. The 1998 Act established the State Electricity Regulatory Commissions (SERCs) to regulate retail rates. It also established the Central Electricity Regulatory Commission (CERC) as an independent statutory body with quasi-judicial powers. The CERC has a mandate to implement national tariff policy and regulate interstate power sales, to advise the central government on the formulation of tariff policy, and to promote competition and efficiency in the electricity sector. The

Electricity Act of 2003 has strengthened several aspects of this legal foundation. This is discussed in Section 5.

Significant government presence in the Indian electricity supply industry complicates the process of establishing an effective and credible regulatory process. There is a large academic literature documenting the incentive problems associated with government ownership of infrastructure industries (see Vickers and Yarrow 1988). Some are unique to developing countries, but others are common to government ownership in general. For example, a recent U.S. Congressional Budget Office study (CBO, 1997) noted the following four sources of incentives for inefficient provision of electricity associated with government ownership:

1. Separation between revenues and costs
2. Reduced cost of capital to government-owned businesses
3. No independent oversight of rates
4. Inadequate maintenance of facilities

All four of these problems appear in the Indian electricity supply industry.

Separation between revenues and costs means that the revenues from the sales of electricity accrue to the government, whereas the costs of production are appropriated as part of the budgetary process. In contrast, a privately owned firm must earn revenues that at least cover its production costs (including a rate of return on capital invested commensurate with the risk borne by investors) or it will be unable to attract the capital necessary to undertake investment to maintain or expand its plant and equipment. More generally, this separation between revenues and costs implies that government funds can be used almost indefinitely to subsidize electricity consumption. The government's continuing failure to implement and enforce the tariffs necessary to recover the cost of supplying electricity is a prime example of this phenomenon.

The reduced cost of capital to government-owned businesses implies that other factors besides economics determine whether investments are made by a government-owned entity. Political factors can and do play a major role in determining the type of technology employed, and the timing and size of new construction.

No independent oversight of rates implies that the government has considerable freedom in using electricity prices to pursue non-economic ends, because it has no requirement to cover production costs or a market-determined rate of return on the initial investment with retail electricity

prices. In particular, the government can set electricity prices sufficiently low to attract electricity intensive industries to certain locations. For example, in the Pacific Northwest of the United States, large government-owned hydroelectricity facilities producing very low priced electricity resulted in the location of a number of electricity intensive industries nearby. Indian farmers are the major beneficiaries of India's low electricity prices, although residential consumers throughout India also benefit from tariffs below the average cost supplying the electricity (Dossani 2004).

The CBO report drew attention to the problem of inadequate maintenance of facilities, by which it meant that, relative to privately owned electricity generation facilities, the government-owned facilities spent considerably less on maintenance than did investor-owned facilities. For example, over the ten-year period from 1986 to 1996, U.S. investor-owned utilities averaged maintenance expenditures that were approximately 7.2 percent of their revenues from electricity sales, whereas the federal government-owned facilities averaged maintenance expenditures that were approximately 4.5 percent of their revenues from electricity sales.⁶ These relatively lower maintenance expenditures appear to have led to lower operating efficiency for the federal government-owned facilities. The CBO report compared the ratio of production to operable generating capacity for federal government and nonfederal government hydropower producers from 1991 to 1995. For the year 1995, this ratio for all federal capacity was 38.7 percent, whereas the average for nonfederal capacity was 51.4 percent. The U.S. government appears to be better able to raise funds for new construction than to do so for undertaking maintenance operations on their existing facilities.

For the past thirty years, the Indian electricity sector has persistently seen low capacity factors from its thermal generation facilities. A major contributor to the initially low capacity factors was inadequate maintenance of thermal generation facilities. As a result of comprehensive efforts to increase plant-level capacity factors—the percent of potential energy that a plant could produce annually that it actually did produce—the overall average Indian thermal plant capacity factor increased to 70 percent in 2001–2 (Lama and Kemal 2003, p. 9), from as low as 44 percent in 1980–81 (Dadhich 2002). Plant-level capacity factors have continued to increase in recent years. The all-India average capacity factor for coal-fired facilities was 74.5 percent for 2004–5 (Central Electricity Authority 2006, p. 136).

Government ownership also makes it easier for customers to rationalize not paying their bills on time, or not paying at all. In most industrialized countries, customers unable to pay prices that reflect the full cost of the electricity are offered subsidized rates which are financed either from general governmental revenues or through higher prices paid by other customers. However, the extent of these subsidies is nowhere near the level it is in India. One task for CERC is to introduce national standards for means testing urban and rural households before they are able to consume at a subsidized rate. This is a typical function of the regulatory process in the United States. For example, California has the California Alternative Rates for Energy (CARE) program which provides a 20 percent discount on electricity bills to households of various combinations of sizes and income levels. This discount is funded through a rate surcharge on all other customers.

The CERC and SERCs should not avoid the difficult decision of determining which customers must pay prices that cover the average cost of supplying electricity and which customers must pay higher prices to subsidize those consumers who find it difficult to pay an unsubsidized price. Rationalizing prices may be at odds with the government's goal of increasing access to electricity in rural areas of the country. However, the fact that subsidies to electricity consumption are close to 1.5 percent of GDP demonstrates that too many consumers receive subsidies. Until retail prices can be increased to cover total production costs, further investment in new generation capacity using government funds would be imprudent. Given the current financial condition of the SEBs, additional private funding for new investment is extremely unlikely to materialize.

In most markets in industrialized countries, when a customer receives a subsidized rate there are restrictions on that customer's consumption. For example, in some markets customers receive subsidized rates in exchange for having a maximum amount they can withdraw from the distribution network during certain time intervals. For example, the maximum amount of energy a customer may be able to withdraw from the network during any given hour could be set at 5 kWh, and their monthly demand might not be allowed to exceed 250 kWh, or a penalty rate would be applied to all consumption above that level. These programs are designed to provide the customer with a subsistence level of electricity at a subsidized rate. If the customer would like to consume beyond that monthly level, he or she would have to switch to a tariff designed to recover the retailer's average cost of supply. The logic behind this arrangement is simple and

compelling: there must be a downside to obtaining a subsidized rate or else customers will have little incentive to pay rates that recover the full cost of producing the electricity. While this model of subsidized rates for a subsistence level of electricity works for urban households, it must be altered to address the tariff structure in the agricultural sector.

Farmers could be endowed with a subsistence monthly consumption level at a subsidized price. They then could be charged at the marginal cost of additional electricity for any consumption above that level and be paid at this marginal price for any reductions in their monthly consumption relative to this baseline amount. For example, the farmer could be given the right to buy 100 kWh each month at 1 cent/kWh, but any consumption beyond that amount could be paid for at a price of 10 cents/kWh, which reflects the SEB's forward-looking marginal cost of supplying additional electricity. If a farmer consumed less than 100 kWh, then he or she would be paid 10 cents/kWh for the difference between 100 kWh and the farmer's actual consumption. The amount the farmer is entitled to purchase at this subsidized rate could decline over time, or the level of the subsidized price could increase over time, to phase out subsidies to agricultural users.

Dossani and Ranganathan (2003) present empirical evidence suggesting that needs-tested agricultural subsidies have the potential to reduce the aggregate amount of subsidies paid. The authors surveyed the willingness to pay for electricity by agricultural users in Andhra Pradesh in the year 2000. They found a surprising degree of heterogeneity across farmers in what they considered to be an "acceptable increase" in the price of electricity. Dossani and Ranganathan argue that greater discriminatory pricing of electricity to farmers by, for example, means-testing subsidies, would raise the amount of revenue collected by approximately 20 percent.

They also examined two quality dimensions for rural electricity supply that could justify higher prices. The first is rostering, which means supplying power in intervals rather than continuously throughout the day. In Andhra Pradesh, rural power is supplied in two blocks, of six and three hours, for a total of nine hours per day. This practice is not favored by some farmers as it can increase their total consumption of electricity. Some farmers waste water because of the need to re-water land only partially watered during the initial period of permissible electricity use during the day. Based on their survey results, Dossani and Ranganathan (2003) argue that rostering results in an excess of usage of power of approximately 15 percent on average.

They also consider the costs of pump motor burnout because of voltage fluctuations and other power quality issues. The survey respondents reported an average of 1.59 pumpset burnouts per year attributable to power quality issues. Based on their survey results, Dossani and Ranganathan (2003) argue that the net result of (a) eliminating pumpset burnout through higher quality supply, (b) increasing average prices by 50 percent for pumpsets exceeding 15 horsepower, and (c) eliminating rostering, would imply a 25 percent reduction in the level of subsidies.

There are a number of minimal requirements that the CERC must impose on all SEBs to begin the process of improving their financial condition. First, all SEBs should submit plans to install meters for 100 percent of their customers, including all agricultural customers, as soon as possible. All SEBs should be required to submit plans for reducing the extent of technical and commercial transmission and distribution losses as soon as possible. The CERC and SERCs should set clear standards for disconnecting all classes of customers that do not pay their bills. These rules should also include terms and conditions for customers to regain their connections if they are able to pay overdue bills. The CERC and the SERCs should work together to formulate a transition plan to raise electricity rates to the levels necessary to recover the going-forward cost of supplying electricity. This does not mean that all subsidies would be eliminated, only that average prices to all customers would rise enough so that SEBs would regain their financial solvency.

To correct the mistaken perception that electricity is plentiful, the CERC should implement a national tariff policy requiring all customers, regardless of how poor they are, to pay a positive marginal price for electricity. Having a meter should be a precondition for a customer to receive service. For customers that are currently unmetered, CERC and the relevant SERC should set a date for terminating unmetered service. With the requirement that all new customers have metered service and an end date for unmetered access, the CERC and relevant SERC could be certain that all customers have metered access by some future date.

One way to transition a customer that currently pays a zero marginal price to a metered price is to set a sufficiently low marginal price so that the customer's monthly bill does not significantly increase immediately as a result of the transition to metered service. Then the customer can be introduced to future marginal price increases on an ability-to-pay basis.

In order to prevent tampering with a customer's meter, the SEB must be able to charge the customer at a penalty rate if it can be determined

that a customer's meter has been altered. For example, the customer's monthly bill would be some penalty rate times the customer's highest monthly consumption over the previous year. The SEB also should have the ability to charge penalties for late payment. Both the process used to determine if a meter has been tampered with and to assess the penalties due, as well as the process for determining the penalties for late or non-payment, should be approved and monitored by the relevant SERC. To ensure consistent standards across the country, the CERC should issue general guidelines for assessing these penalties—guidelines to which all SERCs must comply.

An effective regulatory process must balance the competing interests of the industry participants and Indian consumers. There are a number of ways to increase the effectiveness and credibility of the state-level regulatory process and to adapt the industry to changing market conditions. CERC should establish regulatory guidelines with which the SERCs in each state must comply. A national regulatory policy would increase the commitment of state regulators. Rather than having to shoulder the burden of enforcing politically unpopular decisions, such as universal metering, nonzero marginal prices, and penalties and disconnection for late payment and nonpayment, implementing these as national policies can increase the degree of acceptance for these policies at the state level.

Clearly, all Indian consumers should agree that if electricity is sold to the vast majority of customers for less than it costs to produce, this creates an unsustainable electricity supply industry. Problems arise when one customer or customer class finds a way to pay a lower price, without some corresponding restriction on their consumption behavior. This creates incentives for other customers to attempt to obtain these lower prices, which is why binding maximum consumption restrictions on customers receiving subsidized rates are necessary, as is an automatic phase out of subsidies to agricultural users.

3.1 NATURE OF THE COMMITMENT PROBLEM IN REGULATION

A regulatory process must trade off two competing goals. Specifically, it must have sufficient flexibility to adapt to the changing conditions in the industry, and yet, at the same time, it must possess features that allow it to commit credibly to honoring previous commitments. The electricity industry requires extremely long-lived investments in generation, transmission,

and distribution assets. Privately owned firms will not make the investments necessary for the long-term viability of the industry unless they believe that the regulator and government are willing to commit to allowing the firm the opportunity to earn a return on investment commensurate with the level of risk taken on by investors. For example, if prospective investors feel that the regulatory environment is unstable, they will decline to make investments that may be profitable under a more stable regulatory regime. They may also be willing to pay less for the same asset under an unstable regulatory regime than a stable regulatory regime. Another aspect of regulatory uncertainty is fuel cost uncertainty. The regulator must commit to allow spot electricity prices to increase to reflect increases in fuel costs, or else this will create another source of uncertainty that dulls the incentive for private firms to invest. Even in industrialized countries, an important aspect of electricity market design is building in mechanisms that allow market prices to move with production costs. The need to assure investors that they will have every opportunity to earn an adequate return on their investment underscores the importance of a comprehensive national regulatory policy managed by CERC and implemented at the state level by the various SERCs.

There are a variety of ways for the regulatory process to solve these commitment problems. For example, under the U.S. regulatory process, firms are, by law, allowed the opportunity to recover their production costs as well as a "fair rate of return" on their current "used and useful" capital stock. Under the U.S. regulatory process the firm's current "used and useful" capital stock is referred to as its ratebase. There are well-defined administrative processes for determining the regulated firm's ratebase as a function of its past investments. All of the firm's investment decisions are subject to a "reasonableness or prudence review" by the regulatory body. This review determines whether these investment expenses were reasonable in light of the best forecast of the future level of demand in the industry. If these investment expenditures are prudently incurred, then they enter the firm's ratebase, and the firm is allowed the opportunity to earn the regulated rate of return on its ratebase in the current period so long as these assets remain "used and useful."

This requirement means that the assets are actually used by the firm to produce its output and that they are useful for this activity, implying that it is reasonable to employ them, given the current technology, for electricity production. This commits future regulatory commissions to honor the investment decisions (if they were deemed prudent by previous

regulatory commissions) that are actually employed in the production process. The current regulatory body is charged with setting the "fair rate of return" on these investment expenditures. This rate of return must, by law, then be applied to the firm's ratebase, which depends on all prudently incurred past and present investment expenditures currently used in production. Because the regulated rate of return must be applied to the entire ratebase in determining the firm's revenue requirements, the regulatory body commits to allowing the firm to earn this return on all previous used and useful investment expenditures. This is one example of how to build commitment into the regulatory process.

The CERC should establish national guidelines for computing the ratebase values for all capital equipment owned or operated by federal and state governments and private investors not covered by power purchase agreements. This should be part of a general process led by the CERC to establish general accounting standards for all entities regulated at the state and national level. Topics for standardization include common methods for dealing with accounts receivable and accounts payable, as well as investment expenditures and depreciation schedules for capital equipment. Power purchase agreements between generation unit owners and electricity retailers are an important source of accounts receivable and payable, respectively. The CERC should implement a national policy that requires the SERC to commit to raise sufficient revenues through the rate-making process to recover the payments due under the terms of these contracts in a timely manner. Standardization of accounting practices can make it much easier for the CERC to monitor the economic performance of the SEBs. In addition, standardization of accounting practices can also allow the implementation of yardstick regulation approaches to compensating SEBs for their economic performance.

It is important to emphasize that the ratebase value of a piece of capital equipment need not equal its historical cost or its replacement cost. Some of the capital stock in the Indian electricity supply industry is likely to be of considerably less value than the historical cost less accumulated depreciation expenses. CERC should establish national policies for determining the useful life of generation assets. It should also establish realistic depreciation expense schedules to recover the replacement costs of these projects.

The CERC document, "Final Regulations for Terms and Conditions for Electricity Tariff for the Five-Year Period Beginning April 1, 2004," contains pronouncements consistent with many of these required reforms.⁷ Although this document lays out a framework for determining the costs

of supplying electricity in a consistent manner, the more difficult problem remains one of ensuring that actual tariffs are set sufficiently high to recover these costs and that SEBs receive sufficient revenues to recover the full cost of producing the energy consumed.

3.2 CHARACTERISTICS OF AN APPROPRIATE REGULATORY PROCESS

There are several rules governing the regulatory process that make solving the commitment problem much more straightforward. The first is a requirement of due process, ensuring that the regulatory process be carried out according to some set of established rules and principles. One of the most important established principles is the respect for precedent, that the logic of past decisions will be respected in making future decisions unless there is significant evidence that this logic was faulty. The U.S. regulatory process has a long history of honoring precedent. Because of this, market participants can be confident that past decisions will be respected and that future decisions will be made in a manner consistent with prior logic, unless there is significant evidence that the previous logic was flawed or inconsistent with current laws.

In order to determine if the prior logic is invalid, and that previous decisions based on that logic should be given a lower weight, the regulatory body must have the ability to gather information from market participants. The regulator should therefore be able to compel market participants to provide all of the information it requires to make that determination. A minimum requirement in this regard is annual financial balance sheet information. The regulatory body should also be able to request and receive periodically other information it deems necessary to reach a decision.

Supplemental data requests should be subject to a regulatory burden test. Compliance with the regulatory process should not be excessively burdensome to the firms involved, in the sense that the expected benefits associated with requiring the regulated entity to compile and submit data should be commensurate with the benefits expected to accrue to the regulatory process from having this information available. It cannot be emphasized enough that the quality of the regulatory process depends crucially on the quality of the data made available to the regulator. For this reason, the CERC should establish national standards for data release to the CERC and the SERCs. The CERC should set standards on how this information is reported to it and the SERCs. For example, the CERC could set standards

for electronic submission which would significantly reduce the cost of data analysis for regulatory decision making.

The commitment problem may be difficult for a regulatory body to solve because of the external pressures it faces from market participants or the government. This implies that the agency's budget should be determined independently of any actions it might take, and all of its decision makers should be immune to influence by the government or market participants for predetermined terms of office. The requirement for a budget sufficient to accomplish its duties should be contained in the enabling legislation, which would prevent the government from cutting the agency's budget in the future if it makes decisions contrary to the government's wishes. Crucial to guaranteeing independence is ensuring that the regulatory agency's budget cannot be affected by current decisions that it makes and that the government cannot overturn the regulatory commission's decision except through legislative action or by judicial review.

The option for judicial review of decisions made by the regulatory body is particularly important, because another major requirement for solving the regulatory commitment problem is accountability of the regulatory body for the implications of its decisions. Endowing a regulatory body with the ability to set prices and service quality standards and to implement regulatory rule changes gives it an enormous amount of discretionary power. Without an accompanying obligation to do this in a responsible manner that respects the legal rights of all parties involved and the precedents that exist from previous decisions, there is considerable leeway for opportunistic behavior by the regulatory body. By requiring the regulatory body to be accountable, in the sense of providing market participants with the opportunity to request a judicial review of regulatory decisions, the likelihood that the regulatory body will implement policies that violate previous regulatory commitments will be limited. The enabling legislation for the regulatory body should, therefore, provide it with a mission statement and general guidelines for its operation. This enabling legislation then would form the legal foundation for any attempt to overturn or modify a decision made by a regulatory body through judicial review.

This judicial review should focus on determining whether standard administrative processes and procedures were followed in reaching a decision, rather than reviewing the regulator's technical analysis and judgments. For example, in the United States, the regulatory body is required to follow a well-defined administrative process in reaching a decision. In particular, the basis for any decision it makes must be based on facts and

opinions presented during a formal quasi-legal process. If a party to the decision believes that due process was violated in reaching a decision or that a decision is inconsistent with the legislation governing the regulatory process, then it can appeal the decision to the relevant court.

The early experience of the U.S. regulatory process provides insight on the role of judicial review. During the early stages of the regulation of electric utilities, natural gas pipelines, and other network industries, there were a large number of judicial reviews of decisions made by the newly created regulatory bodies. However, as a large body of legal precedent from these judicial reviews and from previous regulatory decisions developed, the number of major judicial reviews declined significantly.

Transparency of the regulatory process further increases its ability to balance the competing goals of honoring previous regulatory commitments against the flexibility to respond to changing industry conditions. A regulatory process is transparent if there is a single entity that makes the final decision and if there is a clear record of how this decision is made. It is essential that the regulatory body have the right to make the final decision on pricing, service quality, and market rule changes. A process where the regulatory body makes recommendations that must then be ultimately decided by another decision-making body introduces unnecessary uncertainty into the regulatory process and creates additional incentives for market participants or the government to attempt to distort the process. The full responsibility for decision making should reside with a single entity, subject to the opportunity for judicial review of its decisions, as discussed below.

Transparency has several dimensions. The first is that a written record of all information provided by market participants to the regulatory body must be provided to all other market participants. All decisions made by the regulatory body must be issued in written form and must take account of the written evidence or oral evidence (that is subsequently transcribed) entered into the regulatory proceedings. Decisions must address the issues presented by market participants by weighing the relative merits of the arguments made for and against the decision under consideration. Because of the risk of judicial review, it is unacceptable for the regulatory body to disregard sound economic or legal analysis of an issue in favor of a position with no explanation of the reasons behind it. This is what it means to satisfy the due process requirement.

The credibility of the regulatory body would also be severely undermined if market participants thought that it was possible to influence the

regulatory outcome through secret meetings with members of the regulatory body or through other nonpublic forms of interaction.

In the United States, virtually all regulatory bodies prohibit nonpublic meetings between their members and staff and market participants that involve discussions of the issues currently under consideration by the regulatory body within a certain time period of the initiation of the formal decision-making process. This *ex parte* communication rule increases the perceived transparency of the regulatory process, because market participants can be confident that from a certain time forward all information conveyed to the regulatory body relevant to the decision-making process will be made in a public forum.

Another important aspect of an accountable and transparent regulatory process is open access to the proceedings. A permissive standard should be applied to the process of determining whether or not an individual, firm or government agency is allowed to submit evidence to a regulatory proceeding. If an individual is sufficiently interested in the issue to take the time to submit written evidence or an oral argument on an issue, then this level of interest should be sufficient to allow participation in the regulatory proceeding. The process of soliciting input from all interested parties, even though these parties are very likely to argue positions that favor their financial interests, is extremely valuable when the regulatory body is attempting to formulate a new policy to adapt to changing circumstances in the industry.

In many regulatory proceedings in the United States and abroad, the regulatory body will post what is referred to as a notice of proposed rule-making (NOPR). This document will lay out the specific issues that the regulatory body plans to address and solicit input from all interested parties on how it should formulate these proposed rules for regulating the industry. Interveners will then file comments on the regulatory body's initial NOPR after some time lag. Often independent academic commentators submit comments in order to assist the regulatory process with an unbiased analysis of the issue. Then the regulatory body will analyze these comments and issue its final ruling. This decision addresses comments it has received on the NOPR and provides a foundation for the final decision which respects legal precedents and other regulatory decisions. This information gathering process is an essential aspect of the "due process" associated with any major regulatory decision. Strict adherence to this information solicitation and information processing function before implementing any major regulatory policy change limits the ability

of subsequent judicial review to overturn the regulatory body's initial decision for failure to adhere to the standards of due process.

Transparency of the regulatory process in India is crucial to achieving the dual goals of raising average tariffs to a level necessary to recover the forward-looking costs of production and reducing the level of technical and commercial losses to levels commensurate with those in industrialized countries. Achieving these two goals will require a national regulatory policy coordinated by CERC and implemented by SERC along with the full support of the federal- and state-level governments. Rather than attempting this on a state-by-state basis, a superior strategy is for CERC to lead a nationwide, highly visible commitment to more rational electricity pricing. Without such a policy, it is difficult to see how foreign investors will ever again make significant generation investments in India (absent ironclad guarantees from the central government).

3.3 IMPLEMENTING A CREDIBLE REGULATORY PROCESS IN INDIA

The primary goal of regulation is to serve the interests of the citizens of the country or state in their role as consumers. It is not in the long-term interests of consumers for the regulator to set prices that do not allow suppliers ample opportunities to earn an adequate return on their investment. This implies that the regulatory body must recognize that its actions to protect consumers in the short run can increase the long-run costs of serving consumers, so in that sense the regulatory body must also be concerned with the interests of producers. The government may also use the regulatory process to pursue social goals, such as increasing the fraction of households with access to electricity.

Although a regulated firm or a consumer will certainly disagree with a regulatory decision that adversely affects its financial interests, if the firm or consumer can be convinced that the decision serves the best interests of all citizens of India, it will be less likely to attempt to undermine the implementation of a regulatory decision. This logic implies that particularly during the early stages of the restructuring process, the regulatory body must be a consensus builder that oversees the operation of the firms it regulates, rather than an additional layer of managerial oversight for the day-to-day operation of the firms. Because the major goal of the regulatory process in India over the next five years should be the difficult task of putting the SEBs on firm financial footing and reducing both technical

and commercial line losses, consensus building is an extremely important task for the national and state regulators.

The regulatory process is far too complex for a single individual, or even a small number of individuals, to understand all of the details. There should instead be a permanent staff of experts in power systems engineering, economics, and law to assist the regulatory decision-making body. The staff would provide an institutional memory and expertise that is not possible in a regulatory process that relies very heavily on members of the decision-making body appointed to fixed terms for its expertise and institutional memory. Having a permanent staff with an institutional memory also increases the likelihood that the regulatory process will respect due process and precedent. Given the suspected overstaffing at many SEBs, there should be many qualified individuals available for staff positions at the state and federal levels.

Relative to the size of the industries that they oversee, the CERC and a number of the SERCs appear to be understaffed relative to what would be necessary to regulate in an effective and credible manner. The regulatory body should have a permanent professional staff of lawyers, engineers, and regulatory economists. Depending on their workloads, members of the regulatory decision-making body may require their own self-appointed assistants to interact with the permanent staff of their regulatory body.

For comparison, the California Public Utilities Commission (CPUC) employs approximately 850 staff, with half of these devoted to electricity regulation issues. FERC, the national wholesale energy market regulator, employs roughly 1,300 staff with an annual budget of approximately \$200 million.

All successful regulatory bodies in the United States at both the state and the federal levels have the structure of a permanent staff of experts and a decision-making body composed of elected or appointed commissioners serving fixed terms. The staff have a strong interest in preserving the value of their expertise and will therefore be a strong force for respecting precedents and formal process. The major administrative work of the regulatory body is done by the staff.

The usual solution to an understaffing problem is for the regulatory agency to obtain partial or full funding from the entities that it regulates. In the United States, for example, the FERC collects fees from the entities it regulates to pay a significant fraction of its budget, although it can also receive funding from the U.S. government: The CPUC operates in a similar

manner by collecting fees from customers of the entities that it regulates, but the State of California determines its final budget.

4. TRANSITION TO A NATIONAL WHOLESALE ELECTRICITY MARKET

A necessary condition to proceed with a national wholesale market is that the SEBs set tariffs that recover the full cost of supplying customers and ensure that technical and commercial line losses are close to those obtained in the median industrialized country. There are a number of other steps that can be taken in the meantime. The SEBs and the national Central Electricity Authority should be required by the CERC and relevant SERCs to create separate financial accounts to allow the CERC and SERC to break down the cost of retail electricity into the four basic components: (1) wholesale power, (2) transmission services, (3) distribution services, and (4) retailing services.

The SEBs should be encouraged to form separate corporatized entities that are allowed the opportunity by both CERC and SERC to earn the appropriate, regulated rate of return on their assets. Implementing uniform accounting standards across all entities in the electricity supply industry is an essential precondition to financial separation of the SEBs. Consistent methodologies for computing profits and losses across each segment of the industry for each of the SEBs and the Central Electricity Authority will greatly increase the information value of the financial data produced by these different entities.

By accumulating experience with the operation of the regulatory process, the CERC and the SERCs can increase the credibility of the regulatory process and its ability to respond to changing conditions in the industry. Credibility often comes from demonstrating that the industry can function according to the rules set out by the regulatory process without external government intervention.

4.1 SEPARATE PRICES FOR EACH SERVICE

An important step in this process is establishing separate component prices for retail electricity. For example, CERC should establish national guidelines for pricing wholesale power from generation facilities by fuel type. Similar guidelines should be adopted for transmission services,

distribution services, and electricity retailing. Economic logic dictates that distribution costs should vary with the geography and population density of the customers served, although transmission services could be priced on a regional basis.

CERC should set guidelines for computing the regulated price retail price for each customer so that the price is equal to the sum of the component prices. The standard calculation runs as follows:

$$P(\text{retail}) = P(\text{wholesale}) + P(\text{Transmission \& System Operation}) \\ + P(\text{Distribution}) + P(\text{supply})$$

where $P(x)$ is the price of service x . Separately regulated prices for generation, transmission and grid operation, distribution, and electricity supply serve two purposes.

First, they increase the transparency of the price-setting processes to final consumers. With a detailed breakdown of each component of the delivered price of electricity, it is possible for parties sympathetic to raising the retail price of electricity to the level necessary to cover the going-forward cost of all segments of the industry to make their case. These entities can compare the four cost components across states and over time.

Second, separate prices are essential to initiating further restructuring. Potential purchasers of generation assets must know the price that they will receive for electricity produced from these facilities as well as the regulatory mechanism that will be used to set these prices. Similar logic applies to the prices that are set for grid operation and transmission services and the prices set for local distribution and electricity supply.

This equation allows sufficient flexibility to allow different retail prices for different customer classes depending on the cross-customer variation in any of the component prices. For example, the price in one region may be higher because the local distribution price is higher in that region. Setting separate prices for each component of the retail electricity price and requiring that each entity recover its going-forward production costs from sales at these prices will begin the process of establishing a credible and transparent regulatory process for all segments of the industry.

The pricing scheme described above separates the pricing of what are usually considered monopoly services—transmission, system operation and distribution—from what are usually considered potentially competitive services—generation and supply. This scheme will make it easier to introduce competition into the segments of the industry where it is considered feasible. As the transition to competition begins, it may be necessary to raise

the prices paid for monopoly services to attract new investment into these segments of the industry in order to improve the efficiency of the competitive generation market. Credibility to honor commitments to pay for new investment could be handled through a ratebase mechanism similar to the one described earlier.

Based on whatever the CERC and the relevant SERC establish as the ratebase value of the SEB's transmission assets, the regulatory process would then determine the price paid for transmission services and system operation by including an appropriate rate of return on this ratebase. In this same way, the distribution company's assets could be valued and placed in the ratebase to determine its revenue requirements in the regulatory price-setting process.

With a stable regulatory environment that sets prices for wholesale electricity, transmission services, distribution services, and electricity retailing that allow the SEBs to earn a rate of return on their entire ratebase, the process of introducing a national wholesale market can then move forward. A regulated industry structure where consumers pay for the vast majority of the power they consume, in which technical line losses are in line with international standards, and in which the revenues recovered from consumers are sufficient to pay the full costs of supplying electricity would be an environment very attractive to foreign investors. Moreover, a time series of regulated prices for various services purchased or provided by the SEBs would make it earlier for these prospective investors to value specific components of a SEB's business.

4.2 THE BENEFITS OF A FEDERAL SYSTEM

India's federal structure could be extremely beneficial to improving the efficiency of these state-level regulatory processes. All twenty-eight states in India have signed a Memorandum of Understanding (MOU) or Memorandum of Agreement (MOA) with the central government to undertake reforms. Although the geography of India is quite varied, similar technologies are employed for producing, transmitting, and distributing electricity throughout the country. Consequently, there is a major role for cross-state benchmarking of the performance of all or most aspects of the electricity supply industry. For example, comparisons of the heat rates, operating and maintenance costs, outage rates, capacity factors, and even pollutant-emissions rates across similar thermal units would provide valuable

information to all SERCs that set regulated wholesale electricity prices. The CERC could serve as a central clearinghouse for all relevant financial and technical data necessary to set regulated wholesale electricity prices for generating facilities.

A similar approach could be used to collect information on the costs of transmission network construction and operation throughout India. CERC could issue guidelines on how the various entities should submit cost and technical information on their transmission network, and this information could be shared for the purposes of rate-setting among the various SERCs. This process could also be employed to set the prices for distribution services and electricity retailing.

There are a number of statistical methods for measuring productive efficiency that could be employed to measure magnitudes more rigorously. These methods have been used as part of the distribution regulatory process in the Nordic market, and recently recommendations have been made to implement these procedures in the South American countries. Estache, Rossi, and Ruzzier (2004) recommend using such methods to compute measures of firm-level productive efficiency to compare across countries and firms as part of the process of regulating the price of distribution services in South America. While a strict application of these measures to the case of India may not be possible, given problems with data availability, consistent measures of firm-level financial performance and productive efficiency can be very useful for increasing the incentives for efficient production.

For example, through a process coordinated by the CERC, the relevant state-level regulatory commissions could devise methods for compensating firms based on their productive efficiency relative to other similar firms from other parts of the country. These measures could then be used to devise high-powered incentives for efficient production. At a minimum, these measures could simply be compiled by the CERC and made publicly available, with the hope that public disclosure would provide incentives for those at the bottom of the productive efficiency ranking to take steps to improve their standing.

5. THE ELECTRICITY ACT OF 2003 AND PROGRESS TOWARD A CREDIBLE REGULATORY PROCESS

The stated objective of the Electricity Act of 2003 is to "introduce competition, protect consumer's interests and provide power for all."⁸ As the

previous sections have shown, the current conditions in the Indian electricity supply industry make it very unlikely that introducing competition will serve consumers' interests or is the best possible way to provide power for all. However, a number of provisions of the Electricity Act of 2003 do further the goal of establishing a credible regulatory process and a financially viable industry. The purpose of this section is to highlight the positive aspects of the Electricity Act of 2003 and to explain why the provisions of the Act that deal with introducing wholesale competition should not be implemented at this time.

5.1 BENEFICIAL FEATURES OF THE ELECTRICITY ACT

The provisions of the Electricity Act of 2003 most likely to help establish a firm foundation for further industry restructuring are: (1) mandatory SERCs for all states, (2) mandatory metering and stringent penalties for theft of electricity, and (3) the Accelerated Power Development and Reform Programme (APDRP).

According to the Ministry of Power, currently twenty-two states have either constituted or begun the process of constituting a SERC. Of these states, eighteen have issued tariff orders. The Ministry of Power website lists the current status of the process of establishing SERCs in the twenty-eight states. Although not part of the Electricity Act of 2003, all states have securitized their outstanding debts to Central Public Sector Undertakings (CPSUs) using standardized long-term bonds created by the central government. These are all positive steps toward implementing a standardized and more transparent regulatory process with financial separation of the four stages of electricity supply.

There has also been considerable progress in installing metering technology. The Ministry of Power states that 96 percent of the 11 kV distribution network feeders have a meter as of March 2006 versus 81 percent in 2000, and 92 percent of customer-level distribution points have meters versus 77.6 in 2000.⁹ Five states have enacted antitheft legislation, and five have taken regulatory action to increase revenue collection and reduce commercial losses. Although many states experienced increasing average transmission and commercial (AT&C) losses from 2001–2 to 2004–5, the last year of data available, several states experienced declines in AT&C losses over this time period. However, none of these utilities have achieved AT&C losses close to the desired 10 percent level (close to what exists in developed countries) and many have experienced levels many times higher.

Average countrywide AT&C losses are approximately 35 percent, which suggests that a more comprehensive state and national effort is necessary to bring these AT&C losses down.¹⁰

The APDRP is a positive step toward reducing AT&C losses. It has two components: (1) an investment component that provides funds for strengthening and upgrading the subtransmission and distribution networks and installing meters at the 11 kV level and customer level, and (2) an incentive component equivalent to 50 percent of the actual cash loss reduction provided to the SEBs in the form of a grant. Under the investment component, central government funds are provided for 50 percent of the cost of the project in the form of a 50 percent grant and a 50 percent loan. For some states 100 percent of cost is provided by the central government. Priority for this funding is given to those states that are making the most progress toward implementing distribution reforms. For the incentive component, the year 2000–1 is the base year for the calculation of loss reduction payments in subsequent years. Unfortunately, the central budget outlay for these incentive payments has been significantly smaller than the amount of incentive payments actually made in 2002–3 and 2003–4. For both of these years the budget outlay was 35 billion rupees, but only 20.29 billion rupees were disbursed in 2002–3 and 28.59 billion rupees in 2003–4. In addition, the vast majority of these disbursements were concentrated in a relatively small number of states.

Although the experience with the APDRP is encouraging, moving forward with some of the other provisions of the Electricity Act of 2003 at this time could impose significant long-term harm on the India economy. In particular, the Act reduces the barriers to entry for captive electricity generation units and allows these entities to sell surplus energy using open access to the transmission and distribution network. The Act also encourages energy trading. The major problem with all of these provisions is that they limit the potential beneficiaries of competition in electricity supply to those entities able to construct captive electricity generation units. It is difficult to see how small industrial and commercial consumers and residential consumers will benefit from these provisions. It is more likely that any costs that the larger entities would prefer not to bear will be passed on to these customers, because they do not have the option to construct a captive generation unit and sell surplus power to escape these costs. The long-term implication of this policy is likely to be that all large customers that are able to pay for captive facilities will exit the system, leaving the SEBs to serve only the smaller customers that are collectively more costly

to serve and less likely to pay. This process of losing the best customers to the competitive sector could severely hinder the process of improving the financial solvency of the SEBs.

The endpoint of this two-tiered policy would be a higher quality electricity supply with limited redundancy from the bulk transmission network for the large customers able to construct captive generation facilities, and a significantly less reliable supply from the central government and state-owned system to all other customers. In addition, because the large customers would be receiving supply from nearby generation units, there would be little impetus to build out the transmission network to allow more efficient use of India's existing generation resources. The ultimate mix and location of generation units in India would result in a substantially higher average cost of supply for the country because investment decisions for a large fraction of new generation capacity would be made to serve a single large customer rather than customers throughout the entire country. In short, these provisions of the Electricity Act of 2003 might benefit large customers in the short term, but they are very likely to harm small customers in the short and long term and may even eventually harm large customers. A more prudent policy is not to proceed with these provisions of the Act until the preconditions described in the following section are met.

6. A COST-BENEFIT TEST FOR FURTHER RESTRUCTURING

As discussed earlier, the major benefits from introducing a national wholesale electricity market are likely to be realized over the long term. As has been emphasized by the experience of California and a number of other industrialized countries, bid-based spot markets for electricity have a significant downside in terms of the potential to impose significant harm on consumers. Consequently, any decision to move forward with further restructuring should consider this potential downside.

The amount of metering and information technology infrastructure currently in the Indian transmission and distribution grid would make it very difficult to operate a real-time spot market for even a small amount of electricity without significant up-front investments and a time delay sufficient to implement this new technology. Implementing such a scheme would require real-time metering technology throughout the transmission grid to verify whether or not generators and loads actually honored their spot-market obligations in real time. A sophisticated settlement software is

necessary to determine the hourly amounts paid to each market participant for fulfilling their real-time obligations and the amounts collected from each major load-serving entity for their real time electricity consumption. In addition, this settlement mechanism must give all market participants very strong incentives to honor their commitments in real-time because the amount of electricity supplied to the grid must equal the amount consumed at each instant in time.

The operation of an electricity spot market similar to those that currently exist in industrial countries also requires the construction of bidding protocols and market-making software, as well as the ability of all generation-owning and load-serving entities to communicate with the system operator in real time in order to translate commitments won in the spot market into the physical supply and consumption of electricity as rapidly as possible. In this regard, it is useful to note that the start-up cost associated with establishing the California electricity market was \$250 million. The start-up cost for a national short-term electricity market in India may not be as high because of lower labor costs, but these costs are still likely to be significant.

It is important to emphasize that putting in place any sort of bid-based real-time or near-real-time market for energy and/or ancillary services, no matter how small, will still require a significant fraction of these up-front costs. For example, an imbalance energy market, where generators and loads buy and sell energy to make up deviations from their day-ahead or long-term contractual obligations, will require similar levels of start-up costs. Even if less than 5 percent of all energy consumed is traded in this market, significant start-up costs must still be incurred. Real-time metering technology is necessary to monitor real-time consumption and production of energy for compliance with the independent system operator's (ISO's) dispatch instructions. Market-making software is needed to take bids to supply imbalance energy from available generating units in real time in order to set the price for imbalance energy during each time interval.

Settlement software will also be necessary to determine payments and charges to generators and load-serving entities for their purchases and sale of real-time deviations from their contractual obligations. Price-based or non-price-based mechanisms must be in place to allocate in real time scarce transmission capacity to generators wishing to supply more or less energy or load-serving entities wishing to consume more or less energy.

Finally, the balance between electricity supply and demand must be maintained at all times and the ISO must carry sufficient reserve capacity to respond to unforeseen contingencies within the bulk transmission grid and unexpected generating unit outages.

The initial conditions in the Indian electricity supply industry differ in many important dimensions from those in the electricity supply industries of industrialized countries around the world at the time they began the restructuring process. As a general rule, in all of these countries, the price of retail electricity was thought to be high as a result of prices set to recover the embedded cost of poor past investment decisions made by the government-owned monopoly supplier. Inefficiencies in the dispatch process were also thought to increase the price of retail electricity further. Policymakers felt that privatization and the introduction of competition would impose market discipline on the investment behavior of the electricity generation sector. The prevailing view was that political concerns such as energy independence, support for a domestic coal industry, or promotion of renewable energy sources had led to these very costly investment decisions in the past. Given the growing demand for electricity in these countries, providing clear economic signals for new investment in generating capacity was an important policy goal. A major concern expressed in a 1981 study by the United Kingdom Monopolies and Mergers Commission (MMC) was that the pre-privatization market structure did not provide the proper signals for constructing the optimal amount and type of new generation capacity in a timely manner (Armstrong, Cowan, and Vickers 1994, p. 291). In California, a traditionally high-price electricity state, the promise of lower prices for all consumers was the major impetus for the state's recent restructuring efforts. Historically, high electricity prices in California were thought by many observers to be the direct result of poor past investment decisions by the state's regulated utilities.

In all countries, competition to supply electricity from existing plants was seen as a way to provide strong incentives for minimum cost operation of existing facilities. Consequently, restructuring efforts in all industrialized countries were aimed at reducing the retail price of electricity and stimulating the appropriate technology mix and quantity of new investment in generating capacity. Many of the reasons for introducing any sort of spot market for electricity (day-ahead, hour-ahead, or real-time) are not as relevant to India as they were for the other countries of the world that have restructured their electricity supply industry.

6.1 INTERMEDIATE PATH TO WHOLESALE COMPETITION

This does not mean that an intermediate path does not exist that still preserves the option to move forward with a bid-based spot market. This section presents such a proposal. This strategy avoids the significant up-front costs of a spot market but does not give up the opportunity to capture a large fraction of the potential benefits from privatization and the introduction of wholesale competition.

The primary goal of this approach to realizing the benefits of wholesale competition is to develop a forward market for electricity where private investors can sell obligations to supply electricity that can be used to finance new generation capacity investments. Problems with unilateral market power in short-term wholesale markets have proven extremely difficult for developed countries to solve, and many of them have a long history with regulation and competition policy, something that India does not have. Fortunately, market power problems are unlikely to arise in the market for long-term financial contracts that start to make deliveries more than two years into the future because there are few barriers to entry at this time horizon in advance of delivery.

Because all suppliers are going to need to buy and sell deviations from their final day-ahead schedules or longer-term energy schedules, a real-time price must be set. This can be accomplished by the former vertically integrated monopolist operating a real-time imbalance market using cost-based bids. All suppliers must file their costs with the ISO and after they are validated by the ISO they are made publicly available to all market participants. The ISO then dispatches all units based on these costs, which also produces locational marginal prices (LMPs) at all nodes in the network. It is not essential that suppliers be paid or pay their LMP for deviations from their final energy schedules. Retailers and large consumers could also be charged prices aggregated over larger geographic areas.

Initially there is little need to divest capacity from the incumbent SEBs and the CEA. It is more important for the regulator to focus on obtaining reliable start-up, no-load, and variable costs for all units in the control area. The goal of this cost-based dispatch for imbalances in real time is to establish a transparent mechanism that all market participants can use to assess the costs and benefits of using this imbalance mechanism. New entrants can factor expected imbalance costs into their willingness to supply energy through long-term contracts at specific locations in the transmission network. Cost-based dispatch also avoids most of the problems

associated with a transmission network that cannot support a competitive wholesale spot market, an initial condition that exists in India. Setting LMPs using cost-based bids will provide useful information to the ISO about the benefits of transmission upgrades in the network and is an important input into the long-term process of constructing an economically reliable transmission network.

Once this dispatch process has been established, the process of opening the wholesale market to consumers can begin. This should be demand-driven. By this I mean that to the extent that large consumers are willing to subject themselves to the hourly spot price as their default price, the wholesale market should grow.

This market structure implies two types of consumers. The first type of consumer are those that are negawatt suppliers—the demand-side equivalent of privately owned generation owners. These noncore customers must purchase all of their demand at either the hourly spot price or at a forward contract price that they have managed to negotiate with some electricity supplier. In order for this to occur, these customers must have hourly meters installed. Consequently, a necessary condition for a customer to become non-core is an interval meter at their location.

The second type of consumer are those who wish to remain with their monopoly retailer. The monopoly retailer for their geographic area must manage the spot-price risk associated with serving these captive or core customers. Hourly meters are not necessary to serve these core customers. However, meters to record their monthly consumption should be installed on the customer's premises. Devices that allow these customers to benefit from responding to prices that vary with changes in real-time system conditions should be encouraged. The regulator should provide incentives to the retailer serving these customers to set retail prices that vary with system conditions.

The difference between the negawatt suppliers or noncore customers and captive or core customers is that the former group can shop around to any supplier for a better forward contract price for their electricity needs, but can never return to being a captive consumer. Because the negawatt suppliers cannot return to their default provider, in exchange for the opportunity to pay a lower price, they face the risk that there will not be enough new capacity to meet their demand. This will give them incentives to enter into forward contracts that can be used to finance new investments.

In order to set the retail price that the monopoly retailers must pay for wholesale electricity, the state regulator can run periodic auctions for standardized contracts for electricity supply. The SEBs will then be required to buy a pre-specified fraction of their load obligations in these markets. These standardized forward contracts should be sold far enough in advance of delivery to allow the greatest possible participation by new entrants.

SEBs should be required to purchase a minimum fraction of their annual energy requirements for serving their core customers from these auctions over, say, the next six years. Figure 3.1 gives a sample time path of these forward energy requirements. Let QF denote a forecast of the SEB's demand for the coming year prepared by the SERC that regulates it. The SEB would be required to purchase at least $f_1 \times QF$ MWh of energy from these auctions for the coming year ($t = 0$ to $t = 1$), $f_2 \times QF$ MWh of energy during the following year ($t = 1$ to $t = 2$). The required quantities that must be purchased for delivery in years three to six are the values of f_i for ($i = 3, 4, 5, 6$) times QF , respectively. These forward contracting requirements for the SEBs could be enforced through a penalty scheme administered by the SERC that respects national guidelines set by CERC.

These forward contracting requirements would move forward in time according to the same pattern given in Figure 3.1. For example, suppose

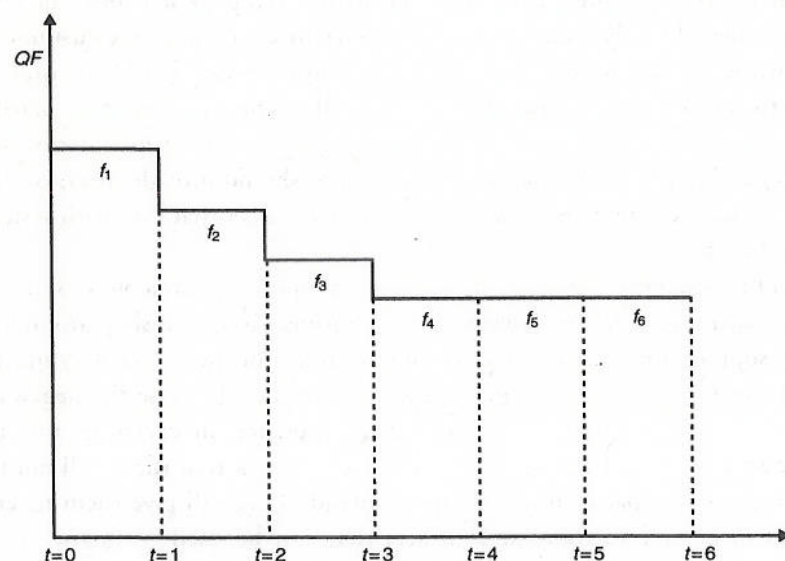


Figure 3.1 Time Path of SEB Forward Contract Obligations

that at some start date the SEB had met its forward contracting requirements for the coming six years given the forecast value of its demand for that year. Then at the end of the first year, period $t = 0$ to $t = 1$ would be reset to the following year and the SERC would provide the SEB with a value of QF for this year. This value of QF and the fractions given in Figure 3.1 would then set the forward contracting requirements for this SEB for the next six years. Forward market requirements for the next six-year time horizon would be updated each year in this manner using any pattern of f_i ($i = 1, \dots, 6$) for the coming six years.

To allow new entrants to obtain the funding necessary to undertake investments in new generation capacity, different delivery requirements could be placed on forward contracts with longer times to delivery. For example, in order to sell a forward contract for delivery in the next three years, the SERC could require that the seller show that this financial commitment is backed up by a generating facility capable of delivering the contracted amount of energy.

Forward contracts for delivery four to six years into the future can be purely financial commitments, in the sense that there is no requirement to demonstrate physical deliverability of the electricity in order to sell the product. However, there should be a requirement to convert this financial commitment to one that is backed by a physical resource if the time to delivery for an outstanding contract is three years or less. This demonstration would first involve showing that an existing plant or a new plant under construction can provide the energy sold.

For new plants, there would be additional steps in the validation process to ensure the plant will actually be able to produce the energy sold by the delivery date. This process would be overseen by the SERC, according to national guidelines set by the CERC. The SERC should also have the authority to impose penalties for failure to meet the various deadlines for project completion. For example, the SERC could require the owner of the proposed new plant to place money in an escrow account at the start of the project to make sure that the company can pay any potential penalties.

If a supplier sells a commitment to a given quantity of energy to be delivered five years in the future to a specific geographic region of India, and if the supplier does not buy this commitment back in a future auction within the following two years, it would have to demonstrate to the SERC that it has the physical capacity to actually provide electricity to that location within three years according to a process administered by the SERC according to national guidelines set by the CERC.

This flexibility for purely financial trading of forward commitments four to six years in the future will provide new entrants with the freedom to sell forward energy commitments that have the option to turn into physical commitments. With such a forward financial commitment one would expect that a supplier could obtain the construction permits and financing for a new generation facility. If the firm is unable to get the new construction started within two to three years of selling the forward financial commitment, then the supplier has the option to sell this obligation back in a subsequent annual or monthly auction. However, assuming the buyer of the original contract never sells its financial obligation to consume energy, it is still guaranteed delivery of energy at the contracted price in the initial contract.

There are many different ways that these auctions could be structured depending on how much flexibility the auction designer would like to give to generation-unit owners and load-serving entities to express their willingness to supply and demand electricity over the next six years. All generation firms could be allowed to bid very flexible price-quantity pairs of energy over the six-year time horizon. The retailers could then submit willingness to purchase price-quantity pairs over this same horizon, and market-clearing prices and quantities or pay-as bid prices and quantities at each location could be determined by maximizing the sum of producer and consumer surplus over all geographic regions and time periods. Such an extremely high-dimensional strategy space for generation unit owners and SEBs provides these entities with the maximum flexibility to express their costs and willingness to consume in the bids they submit. However, this high-dimensional strategy space also has the downside that it provides each generation unit owner with a large number of bid parameters to use to attempt to raise market prices.

The State of New Jersey Basic Generation Supply (BGS) auctions provide a useful model for this process. Each year the New Jersey Public Bureau of Public Utilities (NJBPU) runs a three-year-ahead auction for roughly one-third of the default load obligations of the electricity retailers that are under its jurisdiction. This mechanism has several desirable features. First, it procures the energy required to serve the retailer's default load obligations far enough in advance that entrants can compete to supply this electricity. Second, it only procures one-third of default load obligation in a single year and in that sense spreads the price risk associated with high energy prices in any single year across at least three years. Third, it is run through an anonymous auction mechanism

operated by the NJBPU, and therefore yields a single market-clearing price that is publicly observable and can be used in subsequent regulatory processes.

There are a number of details of the proposed auction mechanism that must be clarified before it can be implemented, but the basic idea of setting minimum annual sales quantities for federal and provincial suppliers and minimum annual purchase quantities for SEBs, both for periods of six years, should be a part of any auction design. The purely financial nature of distant year contracts and physical backing of near-to-delivery contracts is a second feature that should be part of any auction mechanism. As discussed above, as the time until delivery becomes smaller, a supplier would have to firm up the deliverability of the energy. Finally, some penalty mechanism enforcing the minimum sales requirements on suppliers and the minimum purchase requirements on SEBs should also be included in any auction design.

These forward market auctions could also be used to set the wholesale market revenue requirements for electricity retailers. Each year's auction market purchases would be used to set a portion of the retailer's annual wholesale market revenue requirements. For example, suppose the retailer purchased 500 MWh in year 0 for delivery in year 3 at a price of \$20/MWh, 200 MWh in year 1 for delivery in year 3 at a price of \$30/MWh and 100 MWh in year 2 for delivery in year 3 at a price of \$10/MWh. Assuming that 800 MWh is the SERC's forecast of that SEB's demand in year 3, the total amount of revenue that this retailer would be permitted to recover from its customers for wholesale electricity purchases in year 3 would be equal to $(500 \text{ MWh}) \times (\$20/\text{MWh}) + (200 \text{ MWh}) \times (\$30/\text{MWh}) + (100 \text{ MWh}) \times (\$10/\text{MWh}) + \$17,000$.

The SEB should be permitted to offer any number of tariffs to final consumers that they could choose among on a voluntary basis, as long as each of these tariffs is expected to cover the cost of supplying the energy sold under the tariff. Any retail revenues to cover wholesale energy purchases to serve final consumers in excess of this magnitude would be returned to these customers in a lump sum payment. However, if as a result of energy trading activity or innovative retail tariffs the firm was able to reduce its wholesale energy purchase costs below this level, it would be able to keep 100 percent of the cost reductions in higher profits. Conversely, if these trading activities increased total wholesale energy purchase costs beyond this level, then the firm would be required to make up the difference in reduced payments to its shareholders.

Alternatively, the SERC could set the SEB's average wholesale price equal to its portfolio-average forward-contract costs for the coming year. In this case, the average wholesale price implicit in the retail tariffs would be equal to $\$21.25/\text{MWh} = \$17,000/800 \text{ MWh}$. This mechanism may provide incentives for the retailer to increase its sales, because its average wholesale price is fixed, but not its total wholesale revenues. Depending on the values set for the f_i given in Figure 3.1, this mechanism could set wholesale revenue requirements too high or too low. If f_i is set too low and the SEB has not purchased enough forward contracts to hedge the price risk associated with its spot-market purchases, it could be exposed to a potentially very large spot-market obligation to meet its contractual obligations to retail customers. However, setting f_i too high creates the potential for the opposite problem. By requiring the firm to purchase too much energy at too high a price, the SEB's retail price will be set too high. Consequently, in setting the value of f_i for each year, the SERC must balance these two competing goals. However, one point seems clear from this discussion: setting $f_i = 1$, or requiring 100 percent of expected load to be hedged on a year-ahead basis seems to err on the side of setting prices too high. On the other hand, being overly dependent on the short-term market could exacerbate future supply shortfalls. For this reason, the value of f_i should certainly be above 0.90.

The combination of a cost-based imbalance energy market and an anonymous auction-based market for long-term contracts should create strong incentives for private sector participation in the wholesale market—assuming, of course, that retail prices are sufficient to provide the revenues necessary to cover all of the SEB's production costs. Moreover, it is unlikely that there will be significant market power problems in these long-term contract markets if the vast majority of purchases are made far enough in advance of delivery to allow new entrants to compete with firms that own existing generation capacity.

Because the imbalance market is cost-based, suppliers have less of an incentive to delay their electricity sales until the real-time market and there is less need for many of the up-front infrastructure and software investments described earlier that are necessary to operate a bid-based real-time market. Wholesale competition will instead focus on the market that has the greatest potential to be extremely competitive—the market for new generation capacity.

An additional benefit of a cost-based imbalance market is that it is substantially more straightforward to forecast imbalance market exposure

relative to a bid-based market. Market participants need not predict the bidding behavior of other market participants or the impact of this bidding behavior on imbalance energy prices. Instead, all market participants can forecast these prices using the publicly available cost data and load forecasts obtained from the SERC. This greater transparency in imbalance-market exposure reduces the risk associated with selling a forward financial contract for electricity, which increases the competitiveness of the market for forward financial contracts.

7. CONCLUSION

The current financial condition of the Indian electricity supply industry implies that further restructuring is unlikely to benefit the Indian economy over the next five years. The level of subsidies to electricity consumption, primarily to agricultural consumers and residential and small business consumers, are too large for market forces to have much of an impact on the financial condition of the industry. This chapter argues that the benefits to the India economy from reducing these subsidies and returning the SEBs to financial solvency are enormous and easily swamp very optimistic estimates of the benefits from introducing nationwide wholesale competition along with a bid-based spot electricity market.

The solution to the current crisis in the Indian electricity supply industry is establishing the initial conditions necessary for a successful restructuring process as quickly as possible. One of the major lessons from industry restructuring processes around the world over the past fifteen years is that there are significant risks of failure and potentially enormous costs to consumers if it occurs. One way to increase the likelihood of success is by establishing an effective and credible regulatory process at the national and state levels that corrects small flaws before they develop into large and extremely costly disasters.

This chapter outlines a strategy for implementing such a process. Recommendations are also given for reducing the size of the subsidies to electricity consumption and for improving the efficiency of the retail rate-setting process, both of which should help to return the SEBs to financial solvency. In addition, a strategy is outlined for introducing wholesale competition in a manner that recognizes the initial conditions in the Indian electricity supply industry yet still has a high probability of realizing the vast majority of benefits of electricity industry restructuring.

NOTES

1. Fischer and Galetovic (2001) discuss this incident and the regulatory response to it.
2. Wolak (2003a) provides a comprehensive diagnosis of the causes of and cures for the California electricity crisis.
3. See Joskow (1997) for a discussion of this point.
4. Joskow (2003) discusses the unanticipated difficulties encountered in introducing short-term wholesale electricity markets around the world. Wolak (2003b) discusses the unique challenges faced by Latin American countries.
5. See "State Wise Commercial Losses of Power Utilities," available at http://www.apdrp.com/apdrp/projects/pdf/State_wise_Commercial_Losses_of_power_utilities.pdf
6. These numbers do not control for differences in the technology mix of government-owned versus privately owned generation facilities, although it is unclear whether, after controlling for differences in technology mix, this difference in maintenance expenditures as a percent of revenues would be larger or smaller.
7. Available from http://www.cercind.gov.in/28032004/finalregulations_terms&condition.pdf
8. Ministry of Power website, http://powermin.nic.in/indian_electricity_scenario/reforms_introduction.htm
9. Ministry of Power website, http://powermin.nic.in/projects/project_under_apdrp.htm
10. PDRP website, http://www.apdrp.com/apdrp/projects/pdf/AT&C_Loss_of_Power_Utillities.pdf

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