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More Power to India

The Challenge of Electricity Distribution

Sheoli Pargal and Sudeshna Ghosh Banerjee

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Foreword

Two decades after the liberalization of India's economy and a decade after the passage of the forward-looking Electricity Act of 2003, how has India's power sector done? This World Bank review of India's power sector assesses progress in implementing the government's reform agenda and examines the sector along different dimensions—achievements in access, financial and operational performance of utilities, governance, private participation, and coverage and targeting of domestic user subsidies.

The sector has come a long way, as shown in this report, with significant achievements on many fronts: a tripling of conventional generation capacity with active private participation, renewables increasing from zero to 12 percent of the energy mix, the development of a state-of-the-art grid linking the entire country, the transformation of market structure, and the extension of service to more than 250 million users. Several states, programs, and utilities could indeed be beacons for others and are worthy of emulation, including homegrown models of distribution.

Overall, however, the potential of the sector remains unrealized. The lack of reliable power is a leading concern for industry and a potential constraint to growth. Annual per capita consumption is low by global standards and 300 million people lack electricity while the peak deficit is more than 10 percent. Sector finances are weak, with distribution utilities being the main contributors to sector financial losses. Utilities in several states have taken on significant commercial debt to finance their operation, which has led to concerns about poor power sector performance spilling over into the financial sector and broader economy. State electricity boards and distribution utilities also continue to require government support to stay in business, including transfers. This imposes a high opportunity cost on the economy by preempting other development spending. A key message of the report is thus that the distribution segment, still largely government owned and run, will require the sustained attention of the authorities if sector performance is to improve.

Unlike 10 years ago, today stakeholders outside of government, specifically the regulator and commercial financial institutions, critically affect the operating environment and thus power utility performance. The incentives of these players and the government (both as policy maker and as owner) need to be aligned to support utility performance. At the same time many factors that constrain

performance are under the control of the utilities themselves—underpricing, physical losses, and inefficiencies in bill collection—underlining the importance of limiting the government’s role, strengthening regulatory governance, and bolstering competition so that utilities are both pushed to be efficient and permitted to run on commercial lines. This agenda has to be carried forward by the states, facilitated by the central government through technical assistance, knowledge transfer, public information campaigns, and financing. Support from the center for pilots and experimentation with different models of service improvement, leveraging India’s diversity and size, can be an important contribution. The Electricity Act of 2003 and associated policies constitute an enabling policy and regulatory framework for the sector’s development—the focus now must be on implementation.

The World Bank stands ready to partner with India on this journey.

Philippe H. Le Houérou
Vice President, South Asia Region
The World Bank

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Abbreviations

ABT	availability-based tariff
AER	Australian Energy Regulator
AHP	analytic hierarchy process
AMR	automated meter reading
APDRP	Accelerated Power Development and Reform Programme
ApTel	Appellate Tribunal
AT&C	aggregate technical and commercial
BDS	Business Development Services
CAGR	compound annual growth rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CMD	chairman and managing director
CREST	Commercial Reorientation of the Electricity Sector: Toolkit
DERC	Delhi Electricity Regulatory Commission
DF	distribution franchise
discom	distribution company
DPE	Department of Public Enterprises
EA	Electricity Act
EPACT	Electricity Policy Act
FERC	Federal Energy Regulatory Commission
FoR	Forum of Regulators
GDP	gross domestic product
GEB	Gujarat Electricity Board
GIS	Geographic Information System
GUVNL	Gujarat Urja Vikas Nigam
GW	gigawatt
HCPTC	high-capacity power transmission corridor
ID	institutional design
IM	implementation of key regulatory mandates

IPP	independent power producer
ISO	independent system operator
ISTS	interstate transmission system
IT	information technology
kV	kilovolt
kWh	kilowatt-hour
MERC	Maharashtra Electricity Regulatory Commission
MoU	memorandum of understanding
MPERC	Madhya Pradesh Electricity Regulatory Commission
MSETCL	Maharashtra State Electricity Transmission Company
mtpa	million tons per annum
MW	megawatt
NGO	nongovernmental organization
NTPC	National Thermal Power Corporation
OA	open access
O&M	operation and maintenance
PBR	performance-based regulation
PFC	Power Finance Corporation
PGCIL	Power Grid Corporation of India Limited
POC	point of connection
PPA	power purchase agreement
PPP	public-private partnership
PSP	private sector participation
RA	regulatory asset
R-APDRP	Restructured Accelerated Power Development and Reform Programme
REC	Rural Electrification Corporation
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
Rs	rupees
RTO	regional transmission operator
SCADA	supervisory control and data acquisition
SEB	state electricity board
SERC	state electricity regulatory commission
SLDC	state load dispatch center
TSO	transmission system operator
UI	unscheduled interchange
UMPP	ultra-mega power plant

All amounts are in Indian rupees unless otherwise indicated. All dollar amounts are in U.S. dollars.

Indian rupees are converted to dollar amounts using the year-specific exchange rates taken from the *World Development Indicators*.

Year ranges with a slash (such as 2003/04) indicate fiscal years.

Overview

The government of India has emphasized that an efficient, resilient, and financially robust power sector is essential for growth and poverty reduction (Ministry of Power 2005). Almost all investment-climate surveys point to poor availability and quality of power as critical constraints to commercial and manufacturing activity and national competitiveness. Further, more than 300 million Indians live without electricity, and those with power must cope with unreliable supply, pointing to huge unsatisfied demand and restricted consumer welfare.

This report reviews the evolution of the Indian power sector since the landmark Electricity Act of 2003 (EA 2003, or EA), with a focus on distribution as key to the performance and viability of the sector. While all three segments of the power sector—generation, transmission, and distribution—are important, revenues originate with the customer at distribution, so subpar performance there hurts the entire value chain. Persistent operational and financial shortcomings in distribution have repeatedly led to central bailouts for the whole sector, even though power is a “concurrent”¹ subject under the Indian constitution and distribution is almost entirely under state control. Ominously, the recent sharp increase in private investment and market borrowing means power sector difficulties are more likely to spill over to lenders and affect the broader financial sector. Government-initiated reform efforts first focused on the generation and transmission segments, reflecting the urgent need for adding capacity and evacuating it and the complexity of issues to be addressed at the consumer interface. Consequently, distribution improvements have lagged, but it is now clear that they need to be a priority. This report thus analyzes the multiple sources of weakness in distribution and identifies the key challenges to improving performance in the short and medium term.

Evolution of Policies and Institutions

India implemented sweeping economic reforms in 1991 after a debilitating balance-of-payments crisis. The state-dominated power sector was inefficient, hamstrung by undermaintenance and inadequate investment. The sector had been directed to supply power below the cost of production to key consumer

groups, at a huge financial loss. And with only 70,000 megawatts (MW) installed, it was short of generation capacity. With massive additions to capacity needed to support growth, private sector participation was seen as a necessary complement to public investment. Amendments in 1991 to the Electricity Supply Act opened the sector to private participation in generation. As the country continued to face crippling power shortages, states restructured their vertically integrated state electricity boards (SEBs) and established state electricity regulatory commissions (SERCs) under their own reform legislative initiatives to improve performance. The Electricity Regulatory Commission Act of 1998 set up the Central Electricity Regulatory Commission and brought regulatory consistency to the states.

But the commercial performance of state utilities continued to deteriorate, with losses mounting to Rs 250 billion (\$6 billion, or 1.5 percent of gross domestic product or GDP) in 2001/02. By 2002, a decade after the opening of the sector, total SEB debt to central public power suppliers had risen to Rs 400 billion (\$8.5 billion), threatening their financial solvency and resulting in a central bail-out of the state power utilities.

The EA 2003, responding to these developments, was designed as a forward-looking, procompetitive policy and institutional framework for developing the power sector. Superseding current legislation, it delicensed thermal generation, set timelines for open access to transmission and distribution—providing choice to power procurers and end-users—and introduced power trading as a licensed activity to foster competition and encourage private sector entry into generation and transmission. The EA mandated unbundling and corporatizing the SEBs, along with establishing independent central and state regulators and the Appellate Tribunal, with the aim of creating a more accountable and commercial performance culture.² Subsidiary policies that followed laid the groundwork for competitive bulk procurement of power, multiyear tariff frameworks, rural electrification, and renewable energy expansion.

Impressive Achievements in Many Dimensions

Bolstered by a sound policy framework and a favorable economic environment, the sector has taken giant strides on many fronts. Generation capacity tripled between 1991 and 2012, bringing installed capacity to 214 gigawatts (GW), boosted by a surge in the share invested by the private sector, which increased from 3 percent to 29 percent. Renewable energy generation capacity, both grid and off-grid, increased sharply in response to government incentives such as feed-in tariffs on the generation end and renewable purchase obligations on the distribution end, as well as renewable energy certificates that have promoted trade in renewables. From 18 MW in 1990, grid renewable energy capacity rose to 25,856 MW in March 2013, or 12 percent of total capacity; off-grid renewable capacity stands at 825 MW.

By recognizing trading as a licensed activity; opening entry into generation; permitting multiple distribution licensees; introducing a “smart” transmission

tariff to relieve network congestion through point-of-connection pricing; separating transmission from dispatch, trading, and generation; and promoting open access, the EA has led to an active power market and power exchanges that have eased the entry of latent (captive) capacity into the market. The move from negotiated memorandums of understanding with guaranteed rates of return to investors to market-driven competitive procurement brought forth a huge private response in generation and very low tariff bids (though recent experience indicates that allocating fuel-price risk to bidders may have been unrealistic and is now being adjusted). Subsequently, the shift from feed-in tariffs to reverse auctions underpinned the expansion of solar capacity from 17.8 MW in 2010 to 1,440 MW in 2013; competitive bidding for projects under the National Solar Mission drove down prices for grid-connected solar energy to as low as Rs 7.49 (\$0.15) per kilowatt-hour (kWh). A state-of-the-art integrated transmission grid that can balance demand and load flows across the country has been realized—with the recent connection of the southern grid, all of India is now synchronously connected in a single grid.

While achievements in distribution have been less widespread than those in generation and transmission, a major success has been the sharp increase in access to electricity. On the back of an ambitious central scheme, the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), access to electricity rose from 59 percent of the population in 2000 to 74 percent in 2010.

Promising models to obtain efficiencies from private participation in distribution have been developed but need to be scaled up for impact. Globally, private participation has long been considered an effective way of resolving efficiency issues in distribution. In India the “legacy” private distribution utilities in Kolkata, Mumbai, Surat, and Ahmedabad, with their impressive efficiency and customer service, are obvious examples of the potential gains from private participation. They inspired the public-private joint ventures in power distribution taken forward first in Orissa, with limited impact, then in Delhi (learning from Orissa’s experience), with greater success. Recognizing the limited political space for such “privatization,” the EA 2003 established the concept of “distribution franchises.” With the success of the Bhiwandi franchise operation in Maharashtra, which demonstrated the considerable efficiencies and reduction in losses that could be achieved, private participation through the franchise route is today being explored in Bihar, Madhya Pradesh, Maharashtra, and Uttar Pradesh. A push toward rural franchises has also occurred, to help state utilities manage (metering, billing, collection, and operation and maintenance) low-income and low-consumption rural distribution networks, which have expanded under the RGGVY program.

The Agenda for Addressing Distribution Performance Must Now Be a Priority

Despite considerable progress in implementing the EA mandates and associated policies over the past decade, the distribution segment continues to post significant losses. Utility finances—critical to realizing sector goals—deteriorated

sharply over 2003–11. Power sector after-tax losses, excluding state government support (subsidies) to the sector, were Rs 618 billion (\$14 billion) in 2011, equivalent to nearly 17 percent of India's gross fiscal deficit and around 0.7 percent of GDP. These losses are overwhelmingly concentrated among distribution companies (discoms) in the unbundled states and among SEBs and power departments in the states that have not unbundled. When subsidies³ are included as revenue, losses fall by more than half, to Rs 295 billion (\$6.5 billion). Six states reported profits in 2011, but only three would have reported a profit excluding subsidies: Delhi, Kerala, and West Bengal.

Aggregating profits and losses over time, sectorwide accumulated losses stood at Rs 1,146 billion (\$25 billion) in 2011, more than twice (in real terms) the amount in 2003.⁴ Accumulated losses grew at a compound annual growth rate of 9 percent in real terms from 2003, though the share of losses relative to GDP remained stable at about 1.3 percent, largely because the economy also grew strongly over this period. Discoms and bundled utilities (SEBs and power departments) are, once again, the largest contributors to accumulated losses,⁵ though their share has fluctuated from 90 percent in 2003 down to 79 percent in 2008 and back up to 86 percent in 2011.

Sector losses have been financed by heavy borrowing by all sector segments, with total debt growing to Rs 3.5 trillion (\$77 billion) in 2011, or 5 percent of GDP. Discoms are responsible for the largest share of this debt (36 percent in 2011), followed by generation companies, including independent power producers. Many discoms have relied on short-term loans to meet operating expenses in recent years: long-term loans declined from 87 percent of total sector borrowing in 2007 to 77 percent in 2011. The interest burden on utilities from short-term borrowing is onerous, with debt-heavy capital structures becoming more common.⁶

Mounting debt and continuing losses have led to a precipitous decline in discom creditworthiness. In Uttar Pradesh, Rajasthan, Meghalaya, and Haryana, power sector debt exceeded 10 percent of state GDP in 2011. Facing the prospect of huge and increasing nonperforming assets and approaching their sector exposure limits, lenders pulled the plug on loss-making utilities by late 2011. As credit dried up, these discoms were unable to pay for power purchases, with a knock-on effect on upstream (generation) investor sentiment. The absence of alternative buyers for power has spelled trouble for power generation companies, which are overly dependent on state discoms as customers. This, in turn, has slowed investment in generation, resulting in difficulties in that segment as well, as significant funds are locked up in delayed or mothballed generation projects. Thus, at the end of 2011, just 10 years after being bailed out, the sector was looking for another rescue from the center, four times larger than before.⁷

The 2011 crisis was different from that in 2001 because this time players from outside the power sector and government were involved. Lending by banks and financial institutions (to all sector segments) has relied on the quasi-guarantee of state governments in the face of the known insolvency of discoms, the offtaker and source of revenues for the entire sector. In 2011 about half

the sector's borrowing came from commercial banks. Additional amounts were lent at concessional rates by financial institutions such as the Power Finance Corporation (PFC), Rural Electrification Corporation (REC), and Infrastructure Development Finance Company, to bring the total contribution of commercial banks and financial institutions to 86 percent of power sector borrowing. The flow of liquidity limited the pressure on discoms to improve performance and on state governments to permit tariff increases. (It was only in 2011 when banks were directed to stop lending to insolvent utilities that states pushed through tariff increases [Unnikrishnan and Gadgil 2011].) Such profligate lending has harmed banks' capital adequacy and net worth. More than half of 13 major state-owned banks have funded loans to the power sector of 50 percent or more of net worth. At the extreme, the funded exposure of some smaller banks exceeds their net worth, raising concerns over how poor power sector performance and difficulties for some or all of these financial institutions could spread to the financial sector and, possibly, other parts of the economy.

Thus, two decades after the initiation of power sector reforms, an inefficient, loss-making distribution segment and inadequate and unreliable supply have become major constraints to India's growth, inclusion, job creation, and aspirations for middle-income country status.⁸ The peak deficit today is 10.5 percent, and the energy deficit is 7.5 percent. More than 300 million people remain without electricity, and per capita annual consumption at 780 kWh is among the world's lowest levels (Press Information Bureau 2011). Despite the low tariff bids from competitive procurement, the cost of power purchased by utilities has been increasing. And while the private sector has enthusiastically participated in building power plants, there has been less of an interest in inviting private participation into distribution, where its expertise in raising efficiency is most needed.

Analyzing Operational and Financial Performance of Distribution

Aggregate technical and commercial (AT&C) losses, which measure utility operational and financial performance, have fallen from 38 percent to (a still-high) 26 percent over 2003–11. AT&C losses consist of distribution losses,⁹ which comprise losses due to both technical and nontechnical factors, and losses from collection inefficiency. Distribution losses have dropped from 32 percent in 2003 to around 21 percent on average in 2011—so, despite the encouraging trend, utilities still have not been paid for more than a fifth of power they purchased and supplied. In 2011 the lowest distribution losses were in Kerala, at about 12 percent, similar to international best practice.

To understand the relative contribution of different factors, distribution-utility revenue losses¹⁰ can be decomposed by source: from underpricing (average billed tariffs below cost-recovery tariff levels), from undercollection (not collecting the full amount billed), and from physical losses of energy (losses above international norms due to technical reasons or due to nontechnical factors, such as theft). In 2011 the absolute amount lost was highest in Tamil Nadu,

followed by Rajasthan and Andhra Pradesh; losses in five states were more than 100 percent of distribution revenues earned.

Collection efficiency has generally remained stable, rising from 89 percent in 2003 to 94 percent in 2011.¹¹ Most states are above 90 percent, though performance declined in about half the states over 2003–11.

The time taken to collect payments—debtor days—is another operational inefficiency that has contributed, through the collection rate, to the poor financial performance of distribution utilities. Average debtor days have come down from 213 days to around 170 over 2003–11 with the 10 best performers averaging 21 days in 2011 but the 10 worst 489 days, indicating gross mismanagement of cash flow.

In 2003, in aggregate, states were charging an average billed tariff¹² well above cost recovery,¹³ and losses that year were overwhelmingly driven by distribution losses—that is, above the normal physical losses of energy. By contrast, in 2011, in aggregate, states were charging an average billed tariff below cost recovery. Thus, underpricing emerged as an important contributor to losses, though distribution inefficiencies, while smaller than in 2003, continued to be the largest contributor to total losses.

Calculated across all states, the margin of cost recovery declined over 2003–11 because tariff increases failed to keep pace with cost increases. Although the average billed tariff in 2011 was higher than cost recovery in 15 states, technical losses, theft, and undercollection can (and often do) lead to no revenue from a significant amount of power supplied by utilities. The fact that most utilities still make losses despite having tariffs at or above cost-recovery levels reinforces how much operational inefficiencies contribute to utility losses. Only Delhi, Kerala, and West Bengal had tariffs that covered costs in 2011 and made a profit without requiring a subsidy.

The Sector Operating Environment Has Contributed to Discom Financial Difficulties

On the cost side, unforeseen shortages of fuel (mainly coal) and poor planning by discoms have led to a steep rise in the price of bulk power—the main reason for the widening gap between discom costs and revenues. While average revenue grew at a real compound annual growth rate of 6 percent over 2003–11, the average cost of supply rose at about 7 percent, growing by 70 percent in real terms over the period. The share of power purchases in total costs rose from 56 percent in 2003 to 74 percent in 2011. Power has become more expensive because of a decline in domestic fuel availability, resulting in an acute increase in the price of fuel used in generation, and because of poor procurement planning by discoms, which leads to last-minute purchases of power to supply end-consumers. Such purchases must be procured from the spot market and tend to be more expensive than power contracted for longer periods. A sharp increase in the use of imported coal, which is often two to three times as expensive as domestic coal, and power producers' increased use of e-auctions (typically expensive) to

purchase coal have further pushed up the cost of power generation. Rising interest expenses, driven by discoms' increased borrowing to meet cash-flow needs (often due to inadequate revisions in tariffs), have also contributed to escalating costs. The escalation in cost is also not always permitted to be a pass-through, adding to the pressure on discoms.¹⁴

Inefficiencies and lack of coordination among the ministries and agencies responsible have resulted in coal production and supply well below projections.¹⁵ About 76 percent of the coal consumed in India is used by the power sector, and 58 percent of electricity generated comes from coal. Coal India's monopoly on coal production and sales, coupled with its inefficiency, has led to consistent shortfalls in coal availability against official estimates over the past two Five-Year Plans (2002–07 and 2007–12). Targets for coal production have been overly optimistic considering the volume of exploration undertaken in earlier years. Poor coordination among the multiple agencies that need to provide clearances has added long delays to mine development. Infrastructure for evacuation of coal produced has not kept up with production, either. The gap between the amount of coal required (for plants awarded coal linkages and to be commissioned during the Plan period) and the actual increase in coal production, particularly over 2010–12, points to an urgent need for harmonization between the concerned ministries. In fact, a considerable volume of investment in thermal power plants, with power purchase agreements (PPAs) based on the projected availability of cheap, domestic coal, is now likely to remain stranded.

The expense of providing below-cost power to key consumer groups, such as agricultural and rural consumers (a political decision in many states) has also weakened utility finances. The health of distribution is closely linked to the share of agricultural consumers in total consumers. Not only are these consumers heavily cross-subsidized by industrial and commercial consumers as part of government policy, but they also usually require an additional explicit subsidy contribution from the state—the share of agriculture in total electricity consumption was 23 percent in 2011, while revenues from agriculture were only 7 percent of the total. Thus compensation from the state budget to cover the cost of supply to agriculture is critical to utility financial viability.

The problem for utility finances arises because there is often a gap between the volume of subsidies booked by utilities as compensation and the amount received from the government. This worsens the economics of already struggling utilities, undermining their creditworthiness and preventing them from investing to improve service delivery. The gap was Rs 119 billion (\$2.6 billion) for all states in 2011. Since 2003 subsidies booked have grown 12 percent a year and subsidies received by 7 percent a year; the cumulative gap between them was \$10 billion for 2003–11.¹⁶

State support to the power sector includes explicit fiscal transfers in the form of subsidy payments as well as subsidized loans and contributions of equity to utilities. Fiscal transfers to the power sector account for a significant share of state budgetary spending. State support to the power sector averaged 1.3 percent of state GDP in 2011 across the 16 Indian states in which distribution utilities

received support, and was as high as 6 percent in Punjab and 5 percent in Uttarakhand. As a share of the state budget in 2011, state support averaged about 2 percent but was 15 percent in Bihar and 22 percent in Uttarakhand.

Most states also subsidize a substantial portion of domestic consumption. Of all electricity consumed by domestic consumers in India, 87 percent was subsidized in 2010. As the domestic sector consumes almost a quarter of electricity sold, this is equivalent to 21 percent of all electricity consumed, with the average subsidy being Rs 1.5 per kWh. While 25 percent of households lack access to electricity and therefore receive no subsidy, more than half of subsidy payments (52 percent) India-wide went to the richest 40 percent of households in 2010, underlining the potential gain to utility revenues from better targeting that would reduce household subsidies.

Institutional Factors and Governance Shortcomings Are Other Contributors

Key reforms mandated by the EA have still not been implemented in full. EA mandates in six areas—access, quality and affordability, cost recovery, accountability and transparency, renewable energy, and competition—have been carried out unevenly.¹⁷ An index that measures the actions taken by state-level actors (that is, governments, regulatory commissions, and utilities) to realize the objectives of the EA and its associated policies indicates that most states have completed only half the reform actions envisaged. Among the reform areas, statewide performance was worst on promoting competition. Service quality and affordability has seen the most progress, closely followed by access.

In fact, open access, a key enabler of competition under the EA, has still not been implemented in a manner such that a robust merchant market could compensate for a decline in sales to state discoms and thus balance supply and demand. Of the five indicators used in this report to assess progress in promoting competition, only notification of open access regulations and unbundling have been completed by almost all states. Most state regulators have notified wheeling and transmission charges and the cross-subsidy surcharge, but only one has specified a path for the cross-subsidy reductions necessary for open access to take effect.¹⁸ Implementing open access and ensuring the availability of adequate evacuation capacity are necessary to permit third-party sales and deepen competition in the sector. With regard to the states, Delhi has progressed the most in implementing EA mandates, followed by Gujarat, Maharashtra, Madhya Pradesh, and Andhra Pradesh.

Analysis for this report shows that achieving sector outcomes is linked closely to the degree to which each state has implemented the EA, so this is a critical area for follow-through. An index of outcomes on objectives ranging from power availability and affordability, to access and reduction of fiscal burden, to openness and sector financial viability was used to measure overall sector performance. It shows that sector outcomes, in line with the implementation of reforms, have

been uneven across states, with Gujarat and Punjab ranking highest in achievement of outcomes.

Continued state interference in utilities weakens incentives for commercial operation. The EA's requirement for unbundling and corporatization of utilities was intended to limit state involvement in their operations, increase transparency and accountability, and bring a commercial orientation to their operations. But while unbundling the SEBs has progressed quite well on paper, actual separation and functional independence of the unbundled entities is considerably less than it appears—and clearly identifying the contributions of individual entities in the service value chain and holding them accountable for their performance remains difficult.

Corporatization has also been unable to insulate utilities from state interference because boards remain state dominated, lack sufficient decision-making authority, and are rarely evaluated on performance. Utility boards tend to have more government and executive directors than recommended under the corporate governance guidelines issued by the Department of Public Enterprises and fewer independent directors.¹⁹ Only 16 percent of 69 utilities studied have the recommended share of independent directors, and several entirely lack independent directors. Further constraining the boards' autonomy and management's ability to operate on a commercial basis is the state government's involvement in recruitment, personnel, procurement, and enforcement decisions.

The regulatory environment has not sufficiently pushed utilities to improve performance. A lack of accountability, limited autonomy, and constrained technical capacity have restricted the ability of SERCs to create an independent, transparent, and unbiased governance framework for the sector that balances consumer and investor or utility interests. SERCs have been established in all states but have generally struggled to achieve true autonomy from state governments, partly because of relationships built into the EA. In addition, many SERCs lack the resources, such as adequate numbers of professional staff and appropriate information technology (IT) systems, to perform their functions. Most SERCs are nominally promoting consumer empowerment and increasing transparency but need to do far more to promote consumer engagement and ensure that high-quality information is publicly available. Perhaps most important, there is no clear accountability mechanism to hold SERCs responsible for implementing their mandates.

SERCs face an enormous challenge in carrying out their mandates because the utilities they regulate are almost all state owned. As a result, although most SERCs have notified²⁰ the key regulations necessary to enact the EA 2003 mandates, many have yet to implement them fully. The regulatory mandates reviewed in this study relate to tariffs, protection of consumers, standards of performance, open access, renewable energy, and regulations in selected other areas.²¹ On average, states score 74 percent on an index measuring implementation of regulatory mandates. Andhra Pradesh, Himachal Pradesh, and Karnataka are the highest ranking SERCs.

Examining implementation more closely is instructive. For example, while tariffs cover average cost in most states, very few states issue multiyear tariffs that incentivize efficient operations and enable utilities to plan long term. On average, states increased tariffs at least once every two years from 2008 to 2013. Three states increased tariffs each year while Sikkim did not revise tariffs at all in the six-year period. The frequency of tariff increases varied from year to year—for instance, in 2008/09 only 13 states reported tariff increases, compared with 2012/13 when about 26 states issued orders to raise tariffs. Goa—one of the best performers—did not issue a tariff order for the first five years in this period, finally raising tariffs only in 2012/13. Steady revisions in tariffs avoid the shock to consumers from having to adjust to a sudden large jump in the tariff. And they enhance the general acceptability of tariff increases and help prevent receivables, such as “regulatory assets,” from building up in utility accounts.²²

Mounting regulatory assets have added to the discoms’ cash-flow problems, jeopardizing routine operations.²³ In Tamil Nadu, Rajasthan, Punjab, Uttar Pradesh, Haryana, Delhi, and West Bengal, utilities have had to borrow heavily to fund the deficit of revenues over costs. Although the Appellate Tribunal has ruled that regulatory assets must be recovered over three years, the sheer magnitude of current regulatory assets means this would cause a major tariff shock. So, recovery has been spread over a longer period with no relief to utility finances. Exacerbating the problem are delays in “truing up,”²⁴ regulators assigning lower power-purchase costs than used by discoms in their projected revenue requirements to keep starting tariffs low, and the interest burden on cash-strapped discoms that have to borrow to purchase power.

Another source of pressure on utility finances is the mandate to build and “power up” the vast network of lines laid across the country under the central government’s flagship access program, RGGVY. Structural disincentives to supply power in rural areas include low demand (per consumer and also overall), high cost of service provision, and low (frequently below-cost) tariffs. In 2011 utilities lost Rs 3 (\$0.06)–Rs 4 (\$0.08) per unit of power sold to rural consumers; the aggregate burden of serving rural consumers in 2010 was around Rs 200 billion (\$4.4 billion) in 12 large states studied. RGGVY-related losses have also placed a heavy weight on distribution utilities’ finances that state subsidies do not always cover, as estimating the cost of rural service delivery is very difficult. Under RGGVY, the REC provides a 90 percent subsidy for the capital cost of grid extension. But by January 2013 the amount sanctioned by the REC for all RGGVY projects, Rs 342 billion (\$8 billion), covered only 58 percent of the estimated actual cost of Rs 590 billion (\$13 billion), and the government had only disbursed 84 percent of the sanctioned amount. The reasons for this misalignment are inadequate and unrealistic state estimates of the funding required to meet RGGVY goals; the REC’s application of standard cost norms that do not consider geography, cost of living, or other significant factors; a long and unwieldy revisions process, which has deterred states from requesting revisions to approved amounts; and RGGVY’s provision of free connections

only to households below the poverty line, which restricts potential aggregate demand to a small group with low consumption levels.²⁵

A potentially transformative two-part central scheme to increase distribution efficiency, the Restructured Accelerated Power Development and Reform Programme (R-APDRP), has not yet realized its potential. The R-APDRP aims to reduce AT&C losses (to 15 percent) in selected urban areas by supporting baseline data collection and the adoption of IT applications and by providing grant funding to renovate, strengthen, and modernize operational, technical, and service delivery mechanisms for distribution.²⁶ But no state has completed even the first part of the scheme, largely because utilities were not informed of the extensive change management needed for implementation; this was made worse by limited resources, a lack of appropriate capacity, and the absence of a supportive IT ecosystem in the broader economy.

In sum, multiple institutions with diffuse accountability have undermined the sector's commercial orientation. The EA 2003 sought to limit government interference in utility operations, yet state governments are still a major presence with a generally detrimental impact on utility operations. They have exacerbated discoms' financial difficulties by compelling them to borrow to cover operational expenses (given the revenue shortfalls due to under-recovery of power purchase costs and incomplete or late subsidy payments by state governments), by applying political pressure to keep tariffs low, and by pressuring discoms to purchase power during elections to keep voters happy. Irregular and inadequate tariff increases over the past decade, despite state regulators' ability to act on their own initiative, have lowered cost recovery and increased regulatory assets.²⁷ Banks and financial institutions continued financing insolvent discoms through 2011, ignoring due diligence and prudential norms as lending to unbundled discoms grew 35 percent a year over the previous five years. This flow of liquidity limited the pressure on discoms to improve performance and on state governments to allow tariff increases.

Way Forward: Priority Areas for Action

Poor power sector performance has its roots in distribution inefficiencies and limited accountability, so fixing them will help improve service delivery and other metrics of sector performance, put the sector on a financially sustainable path, and ensure that power is no longer a bottleneck for growth.

Priorities for action are as follows:

Implement fully the key EA mandates, especially those on competition and distribution (tariffs, open access, and standards of performance). This will incentivize loss reduction, modernize operations, and improve service delivery and cost recovery, thus bringing distribution performance up to international benchmarks of quality.

Ensure regulatory autonomy, effectiveness, and accountability. Widespread concerns about objectivity of decisions and autonomy of decision making arise from the revolving door among the regulator, utility, and government, which results

from the sector's limited pool of qualified staff. One option would be to establish a common pool of regulatory staff working across states and regulatory commissions. Financial autonomy could be enhanced by charging regulatory expenses to the state's consolidated fund so that the SERC has a dedicated, independent source of funding.

Most critically, safeguards need to be developed against the misuse of section 108 of the EA, which permits states to "direct" SERCs. The limited ability of SERCs to penalize state-owned utilities and to overcome state political considerations (on tariff increases, for example) highlights the need to weaken the connection among a state government, its utilities, and the state electricity regulator. Establishing four or five regional regulators responsible for regulating the sector in a group of states is an option. An overarching issue is enhancing the accountability of regulators. Given the general lack of involvement of the state legislatures, alternatives include reporting every six months, possibly through the Forum of Regulators, to a standing Parliamentary Committee.

Ensuring that high-quality, updated data are publicly available and that these data are used for monitoring and benchmarking performance and for planning and decision making is key to incentivizing improved utility performance.²⁸ The current dearth of consistent, reliable, updated data hampers sound management. The regulator can also bring greater transparency and accountability to sector institutions by regularly collecting and publishing data on performance targets and achievements. A statutory requirement for utilities to regularly collect primary data is advisable, including data on customer satisfaction and state performance with respect to subsidy commitments. Third-party monitoring should be encouraged.

Insulate utilities from state government to prevent interference with internal operations. State utilities should comply with corporate governance guidelines from the Department of Public Enterprises on including independent directors on boards and limiting the share of executive directors on them. Independent directors should be appointed by a committee with members from entities like the Central Electricity Authority or other representatives of the public interest. An arm's-length relationship between government and utility can be institutionalized more easily if utilities' articles of association specify a limited role for the government. Using compliance with listing requirements ("shadow" listing) as a precondition for central or other support can bring greater accountability to utility boards, while limiting state interference. Divesting an ownership share to central public sector undertakings such as the National Thermal Power Corporation (NTPC) or Power Grid Corporation of India, which are recognized for strong results, may also limit state government influence because, as equity owners, these undertakings would have the ability to push for better performance. Utility performance can be strengthened through memorandums of understanding, following the practice of central public sector undertakings, many with exemplary performance records. States also need to be held responsible for making timely and complete subsidy payments when they mandate below-cost supply of power

to certain consumer groups. The central government's budgetary transfer to the states could be a potential source for making up the shortfall if the state government does not make the payments due.

Use central programs and other support to incentivize operational and financial efficiency. The central government and its agencies have immense financial leverage. The large centrally sponsored programs (such as RGGVY and R-APDRP) can be used to promote responsible utility and state government behavior, particularly if program implementation is coordinated and if disbursements are tied to reaching operational and financial performance targets.²⁹ Another promising approach would be consistent use by the PFC and REC of ratings recently developed by the Ministry of Power as a core input in lending decisions (Ministry of Power 2013). As PFC and REC are the leading lenders to the sector, this would emphasize the need to achieve and maintain strong operational and financial performance.

Make better use of India's size and diversity to experiment with and learn from different models of service provision, including private sector participation through joint ventures (Delhi), franchising (Bhiwandi), management contracts, and so on. Attracting outside expertise and investment for improving distribution faces issues such as a lack of reliable information on asset quality; very different demand, needs, and ability to pay of rural and urban consumers that the same utility serves; long-lived assets that require heavy upfront investment; and government sensitivity to potential for "extra" profits being earned by private investors leading to excessive conditionality (damping interest in the newer franchises offered).

On these factors, potential approaches include:

- Support learning by doing, with management contracts or franchises that permit the discovery of the true state of assets and that bring basic efficiencies to operations before specifying investment requirements over the longer term.³⁰
- Ring-fence urban and rural customers and consider license, franchise, or public-private partnership (PPP) models³¹ only in urban areas, while letting state discoms remain responsible for rural supply (or separately contracting out specific functions like revenue collection to a rural franchisee) and assigning low-cost public sector generation (such as NTPC PPAs) to state discoms serving rural areas. The private urban operators would be responsible for procuring power for their own consumers, and could contribute transparently to a universal service fund that would cross-subsidize rural supply.
- Establish urban franchises and encourage the franchisees to gradually expand their services to cover rural areas (through a series of concentric circles, for example) so that learning consolidates over time. Variants of this basic approach could include permitting private entrants to offer greater service reliability (than the standard mandated) upon payment of fees on top of the basic, regulated tariff.

Promote electrification in a financially responsible manner and support diverse delivery models. Rural service delivery will become viable only if discoms are compensated fully for supplying power to rural consumers. Supporting productive uses of power (through capacity building, provision of information, complementary microfinance, and technical support) is critical for aggregating the rural load and improving the commercial viability of rural service delivery. Beyond this, funding needs to be allocated in the state budget to make up the shortfall in discom revenues from serving rural consumers. While increasing rural loads will make it cost-effective to meter, bill, and collect, technology innovations and rural collection franchisees can help reduce the associated transaction costs. Prepaid meters would lower commercial risks to utilities and grant rural households more control over their consumption.³² State utilities may also benefit from exploring management contracts with private operators who can deploy new metering technology. Using own-state funds to extend free connections to households above the poverty line can raise community support and improve sustainability of the access expansion achieved.

A single central agency for planning and monitoring grid and off-grid investments can promote coordination by leading the development and regular updating of state rural electrification plans and providing a countrywide picture of the rollout of grid and off-grid facilities. Coordination would require more reliable information on populations without electricity, both in villages with electricity (important for state utilities) and in villages without power (important for off-grid programs and providers).

Rationalize domestic tariff structures to improve targeting and reduce the fiscal burden. An accurate system of identifying households below the poverty line can better target subsidies to the poor. Until such a system is functional, it would be useful to work toward rationalizing tariff structures through:

- Volume-differentiated tariffs instead of incremental block tariffs. In volume-differentiated tariffs, households are grouped by total monthly consumption, and each household in a group pays the same (constant) tariff for every unit of power it consumes.
- Tariff block cutoffs that better match the electricity consumption patterns of households at different incomes.
- Charging above cost-recovery tariffs to higher consuming households. States with fairly low fiscal costs of subsidies achieve this by limiting the subsidy, restricting how many households receive the subsidy, and charging a cross-subsidy to some households.

Notes

1. Both central and state legislatures have a role in developing policy.
2. The sector has moved away from vertically integrated SEBs. Nineteen of India's 29 states now have unbundled generation, transmission, and distribution entities. As of 2013, 28 regulatory commissions have been established.

3. Such subsidies are primarily given to discoms to compensate for below-cost tariffs charged to agriculture and domestic consumers on equity and political grounds.
4. This figure includes subsidies (booked) from state governments as revenue.
5. Among states with the highest level of accumulated losses are Uttar Pradesh, Madhya Pradesh, Tamil Nadu, and Jharkhand. Five states together account for 75 percent of the total. By contrast, Kerala, Gujarat, Andhra Pradesh, Goa, and West Bengal had accumulated profits in 2003–11.
6. The balance sheets of distribution companies have grown, fueled mainly by debt, but these financial liabilities have not created assets.
7. In October 2012 the government announced a Scheme for Financial Restructuring of State Distribution Companies, available to all loss-making discoms that wish to participate, which potentially amounts to a bailout of about Rs 1.9 trillion.
8. The Integrated Energy Policy of 2006 forecasts that generation capacity will need to increase to about 800 GW by 2031 to meet predicted demand and sustain growth of 8 percent a year—four times current generation capacity.
9. That is, the difference between input energy (which is paid for by the utility) and energy sold (which generates revenues for the utility).
10. That is, the difference between total revenues accrued and total costs = profit before tax.
11. *Collection efficiency* is the proportion of energy realized (as revenue) to energy billed; anything less than 100 percent is inefficient.
12. The average billed tariff is revenues billed/energy sold.
13. While cost recovery basically requires the tariff to equal or exceed average cost, a more stringent requirement is used in this report. *Cost recovery* is the tariff level that covers (equals) average cost plus a premium to account for “normal” distribution losses, which are set at 10 percent for India in this analysis. Thus, an efficiently operating utility (with normal distribution losses and 100 percent collection) that has a tariff equal to cost recovery, as defined above, would break even.
14. There are also significant inefficiencies in fuel use by generation that feed into end-user tariffs. While an important area for immediate action by regulators to capture possible savings, over the medium term, as existing power purchase agreements wind down and all new power is procured through competitive bidding, this source of inefficiency can be expected to decline.
15. While beyond this report’s scope, a considerable body of work has analyzed the options for moving India to a lower carbon growth path and increasing the share of renewable energy in India’s generation mix. See, for example, the World Bank studies *Unleashing the Potential of Renewable Energy in India* (Sargsyan and others 2011), *Energy Intensive Sectors of the Indian Economy: Path to Low Carbon Development* (Gaba, Cormier, and Rogers 2011), and *Development of Local Supply Chain: A Critical Link for Concentrated Solar Power in India* (Kulichenko and Khanna 2013).
16. Between 2003 and 2011 cumulative subsidies booked were Rs 1,496 billion (\$32 billion) and received were Rs 1,044 billion (\$22 billion).
17. Delhi has progressed the most by far in implementing EA mandates, followed by Gujarat, Maharashtra, Madhya Pradesh, and Andhra Pradesh. Sector outcomes, which are highly correlated with implementation of EA mandates, have also been uneven across states, with Gujarat and Punjab ranking highest.

18. All but two states have notified open access regulations, and 13 states have reduced cross-subsidy surcharges over the last five years. Only 10 states have initiated competitive power procurement, and only 8 have begun implementation of an availability-based tariff (ABT) beyond notifying ABT regulations. The regulator in Madhya Pradesh notified a cross-subsidy reduction roadmap in 2007, but the state has not been able to achieve the targets set. Kerala notified “Principles for determination of road map for cross subsidy reduction for Distribution Licensees” in 2012, while Maharashtra and Goa have issued *draft* regulations for “Principles for determination of road map for cross subsidy reduction for Distribution Licensees” in 2010 and 2012, respectively.
19. While most utilities comply with the mandated corporate governance requirements of the Companies Act, far fewer follow the recommended guidelines of the Department of Public Enterprises, and very few support their boards with information-driven processes and robust performance management systems, which would boost accountability and profitability.
20. In India “notifying” a regulation means the regulation has been published in the necessary channels and is enforceable.
21. Specifically, regulations related to the supply code, power trading, metering, multiyear tariffs, and intra-state ABTs.
22. *Regulatory assets* are dues to the discoms, typically from tariff increases that the regulator accepts as justified but does not allow in the year they are incurred to avoid a sudden jump in tariffs, on the presumption that they will be recovered through gradual tariff increases in the future.
23. Borrowing against regulatory assets is becoming less feasible. Because commercial banks are unsure how to value regulatory assets that may not be worth their face value, discoms can no longer borrow up to the full amount of the regulatory assets they own.
24. In other words, adjusting the value (for example, of costs, revenues, and tariffs) approved by the regulator in advance (when passing a tariff order) against what was actually achieved. In this instance, actual costs are used to update the cost estimates provided by utilities in their tariff petitions.
25. Increasing both the consumer base and per consumer consumption levels will address low load, and for this it will be critical to improve the quality of supply so that there is greater consumer interest in connecting to the grid, thus generating effective demand.
26. The program requires participating utilities to demonstrate performance improvements (sustained loss reduction) to obtain financial assistance. Thus utilities need to collect accurate baseline data and measure performance. To ensure data integrity, reliable and “no manual touch” systems need to be established for data collection, while adopting IT for energy accounting. Under the program, there is support for both aspects, recognizing that they are preconditions for successful distribution-strengthening projects.
27. Nationwide it is estimated that regulatory assets are more than Rs 700 billion (\$15 billion) and that the interest cost alone adds up to around Rs 95 billion (\$2 billion) a year.
28. The Implementation of Reforms Index, Sector Outcomes Index, and the Analytic Hierarchy Process Index illustrate the potential options that can be considered (see chapters 4 and 5).

29. Payment release could be conditional on concurrence with the performance report by lenders' representatives on utility boards.
30. "Try before you buy." Operating the system will give the incumbent franchisee an information advantage when bidding for concessions or privatizing the utility (if that is envisaged in the next stage). Appropriate mechanisms for capturing this knowledge and handling the information advantage will need to be developed and will need to provide incentives for franchisee performance but also allow for an open competitive procurement process.
31. Delhi utilities are technically PPPs as they are joint ventures between the government of Delhi and the different licensees.
32. Because many rural dwellers in India already use prepaid cards for mobile-phone airtime, mobile phones could be trialed to pay electricity bills, similar to M-Pesa in Kenya.

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Introduction

Two decades after the government initiated reforms designed to bring about a commercial orientation in the power sector and to improve service delivery, India's power sector has made major strides in extending access, adding generating capacity, and developing competitive power markets and a national transmission network, to name but a few. But inadequate and unreliable power supply continues to constrain India's growth, inclusion, job creation, and aspirations for middle-income-country status. Despite significant achievements in the policy and regulatory space, much of the government's power sector reform agenda has yet to be accomplished. A comprehensive analysis of these achievements and the remaining challenges, particularly since the passage of the landmark Electricity Act of 2003, forms the core of this report.

The report reviews the evolution of the power sector since 2003 through the lens of distribution. The fortunes of the whole sector are closely intertwined with the distribution business segment because it is the link between the sector and consumers: it is where revenues are generated that feed back to the upstream generation and transmission segments. The continuing underperformance of distribution has prevented the sector from providing adequate and reliable power to consumers. Several outside stakeholders—from central and state governments and regulators to lenders—affect distribution performance. At the same time, inefficiencies and lack of coordination in the upstream segments¹ add to the cost of power purchased by distribution companies, which is passed on to consumers. This report also highlights successful cases from different parts of India that may warrant adaptation and adoption elsewhere, as well as provides some lessons learned.

Underpinning this report are five standalone background papers, each exploring an issue in depth (see appendix P). These issues include access to electricity, domestic tariff subsidies, sector and utility governance, private sector participation, and the operational and financial performance of utilities. These papers inform the report's analysis of different dimensions of distribution sector performance at the state level.

A key contribution of this sector work is a comprehensive, user-friendly utility- and state-level dataset that has provided the information base for the analysis in the background papers and this report (see appendix O). Information has been collated from a wide array of publicly available data sources augmented with data obtained through primary research, including interviews with representatives of utilities and regulators. The main public data sources accessed include the Power Finance Corporation reports on “Performance of State Power Utilities” covering 2003–11 (PFC 2006, 2007, 2008, 2009, 2010, 2011, 2012); the state electricity regulatory commission (SERC) and utility annual reports, annual accounts, and websites; and the National Sample Survey in various years. The dataset covers 116 power utilities and 28 SERCs across all 29 states from 2003 to 2011. In addition, customized questionnaires were used to understand reform implementation, corporate governance in utilities, and regulatory performance. Finally, a detailed field study was carried out in 2012 to understand the performance and challenges faced in implementing the government’s rural electrification program, the Rajiv Gandhi Grameen Vidyutikaran Yojana. The dataset will be made publicly available to academics, students, researchers, and others through the World Bank’s Open Data platform.

This report is divided into seven chapters. Chapter 1 reviews the evolution of sector policies and institutions since the start of sector reforms in the early 1990s. Chapter 2 lays out the sector’s achievements—contrasted in chapter 3 by the deterioration of distribution finances, the drivers of which are detailed in chapter 4. Chapter 5 presents the implementation status of sector reforms and the impact on sector outcomes, while chapter 6 discusses the governance and institutional factors that circumscribe utility operations and thus affect performance. Chapter 7 presents a succinct set of suggestions to support the sector’s pursuit of a commercial orientation and efficient service delivery.

One of this report’s objectives has been to showcase the diversity of experiences in India—the heterogeneity among states ensures that they have many opportunities to learn from each other. More widely, wherever relevant, the report presents lessons from global experience.

Note

1. While beyond this report’s scope, a considerable body of work has analyzed the options for moving India to a lower carbon growth path and increasing the share of renewable energy in India’s generation mix. See, for example, World Bank studies on *Unleashing the Potential of Renewable Energy in India* (Sargsyan and others 2011); *Energy Intensive Sectors of the Indian Economy: Path to Low Carbon Development* (Gaba, Cormier, and Rogers 2011); and *Development of Local Supply Chain: A Critical Link for Concentrated Solar Power in India* (Kulichenko and Khanna 2013).

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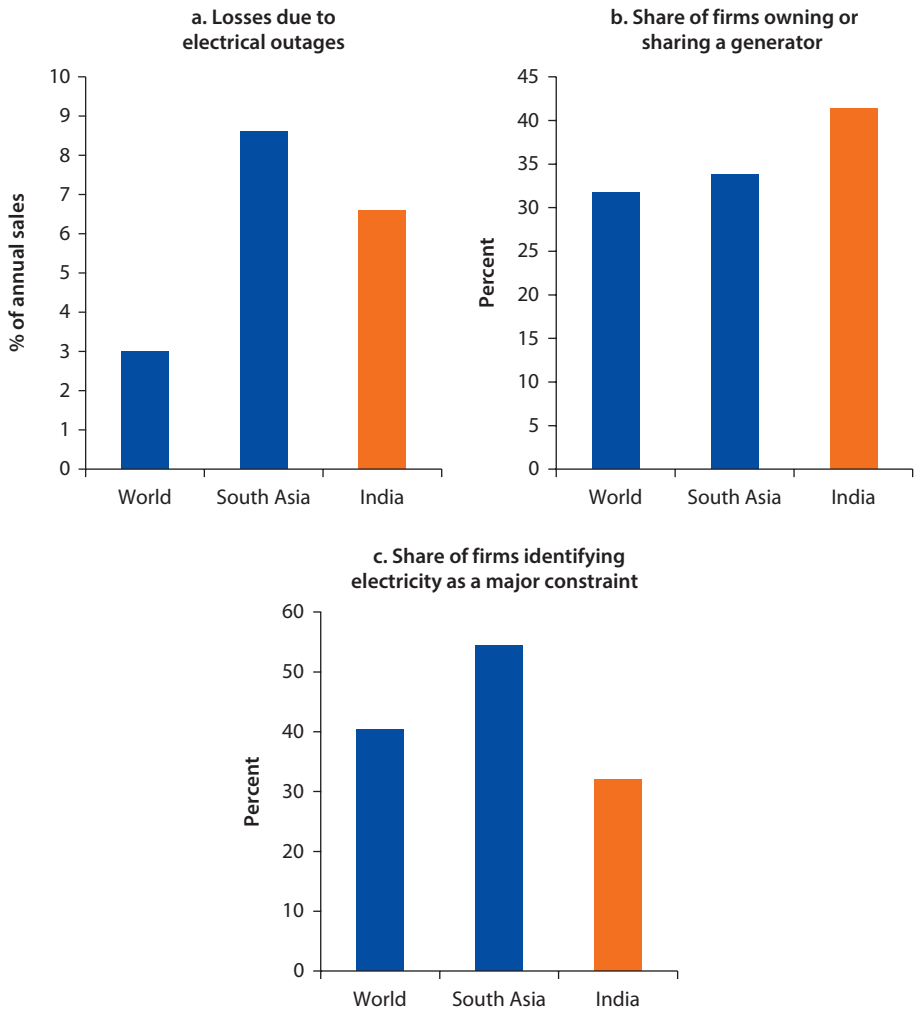
Evolution of Policies and Institutions

The importance of reliable electricity for economic development is most apparent when it is absent—and so becomes a constraint. Inadequate and unreliable power supply can result in lost revenues for enterprises and reduce the welfare of household consumers. That power quality affects economic development is supported by recent literature.¹

For India a 2012 survey by the Federation of Indian Chambers of Commerce and Industry found that the lack of affordable and quality power has been a serious detriment to the health and stability of Indian industry, especially small and medium enterprises. The most likely source of backup power is a generator, for which enterprises pay Rs 12–16 (\$0.22–0.30) per kilowatt-hour (kWh)—far more than they pay for grid electricity, Rs 5.0–8.5/kWh (\$0.09–0.16/kWh). The costs incurred to mitigate the impact of power outages range from around Rs 1,000 (\$18.70) to more than Rs 40,000 (\$749) a day for each firm. Of surveyed firms, 61 percent said that they were willing to pay more for reliable and uninterrupted power (FICCI 2012). A 2006 World Bank investment climate assessment indicated an almost 7 percent loss in production or merchandise value due to power outages or surges from the public grid (World Bank 2006). Forty-one percent of surveyed firms owned generators (figure 1.1), which supplied around 10 percent of their electricity. Thirty-two percent of firms identified electricity as a major constraint to their business operation.

On a different dimension, India ranks 99th in the world on the ease of getting a connection for a typical commercial establishment. On average, it requires seven different procedures spanning 67 days—against 28 days in China, 35 in Thailand, 36 in Singapore, and 41 in Hong Kong SAR, China (World Bank 2013a). For households, not only do 300 million Indians live without electricity but those who do have power receive an inadequate and unreliable supply, especially in rural areas. India's per capita annual consumption, 780 kWh, is among the world's lowest, and far below that in other emerging economies.

The power sector will need to develop consistent with the demands placed on it by the country's growth trajectory, urbanization patterns over time, and

Figure 1.1 Impact of Inadequate and Unreliable Electricity on Firms

Source: World Bank 2013b.

Note: All surveys are for latest available year; India's enterprise survey is for 2006.

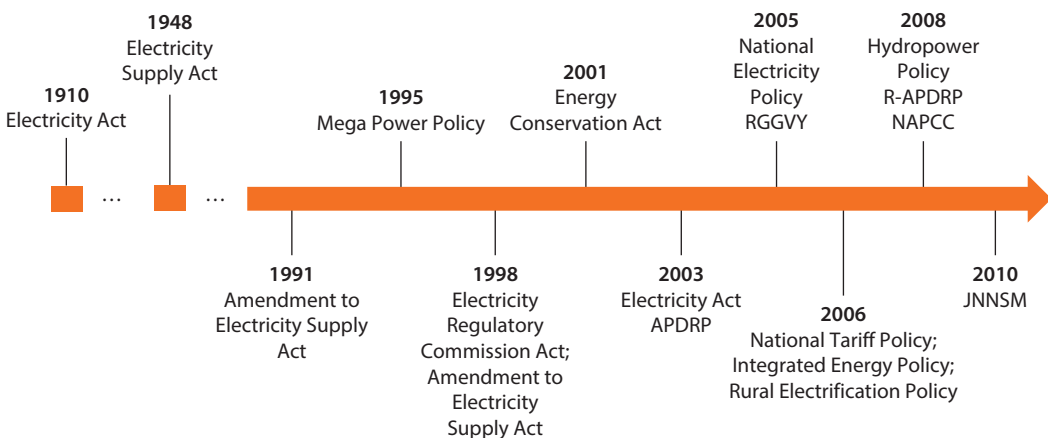
consumer aspirations. In the next two decades India will face immense challenges if it is to sustain the 8–10 percent economic growth required to end poverty and achieve human development goals. According to the Planning Commission, by 2032 India will require a total primary energy supply of some 80 million terajoules, meaning the country will have to almost triple its 2010 supply of 29 million terajoules—a compound annual growth rate of 4.7 percent. India will also need to raise installed electricity capacity by at least five or six times 2003–04 levels to meet demand in 2031–32 (Planning Commission 2006). Powering India will thus require the emergence of a commercially viable sector.

Policy Space Uneventful through 1991

The importance of electricity has been recognized in India’s policy space since the Electricity Supply Act of 1948. This first major electricity sector policy in independent India cemented the sector’s status as a “concurrent” subject (meaning that both central and state legislatures have a role in developing the policy framework; figure 1.2). It established the Central Electricity Authority as an advisory body on national power planning, policy making, and monitoring progress, and created state electricity boards (SEBs)—state-level vertically integrated utilities responsible for power generation, transmission, and distribution and for setting most tariffs. In 1956 the Industrial Policy Resolution further expanded the government’s role, nationalizing the generation and distribution of electricity, except for the private licenses that already existed (Bajaj and Sharma 2010; Panda and Patel 2010).

Electricity sector policies changed little until 1991, when India’s economy faced a debilitating foreign exchange crisis. India embraced broad-based reforms and moved away from the inward orientation of the past. The 1991 crisis brought a new focus to the power sector’s deteriorating state. At that time India had a generation capacity of 69 gigawatts, a peak deficit of 16 percent, and an electrification rate of 42 percent. The power industry comprised 19 SEBs and six electricity departments,² which together were responsible for more than 70 percent of the country’s power generation capacity and almost all its distribution. The power sector was in extremely poor financial condition, with losses of roughly Rs 40 billion (\$0.85 billion)—0.7 percent of gross domestic product (GDP) at the time—and a cost-recovery

Figure 1.2 Electricity Sector Policies and Schemes over Time



Source: World Bank compilation.

Note: APDRP = Accelerated Power Development and Restructuring Programme; JNNSM = Jawaharlal Nehru National Solar Mission; NAPCC = National Action Plan on Climate Change; R-APDRP = Restructured Accelerated Power Development and Reform Programme; RGGVY = Rajiv Gandhi Grameen Vidyutikaran Yojana.

rate of only 79 percent. It also suffered from high technical inefficiencies, including transmission and distribution losses of around 23 percent and a plant load factor of only 54 percent. Peak and energy deficits were 18.8 percent and 7.7 percent, respectively.

The crisis brought home the importance of power sector development, setting in motion the first phase of a power sector reform agenda. The agenda initially focused on boosting generation capacity, notably by opening the sector to foreign and private investment. Amendments to the Electricity Supply Act, passed in 1991, allowed private players, including foreign investors, to come in as independent power producers and enter into long-term supply contracts—power purchase agreements—with utilities. But the reform agenda stopped there, doing nothing to address the underlying drivers of the sector's poor performance or to dilute state government control over the politically sensitive distribution sector.

Sector Restructuring and Independent Regulation in the 1990s

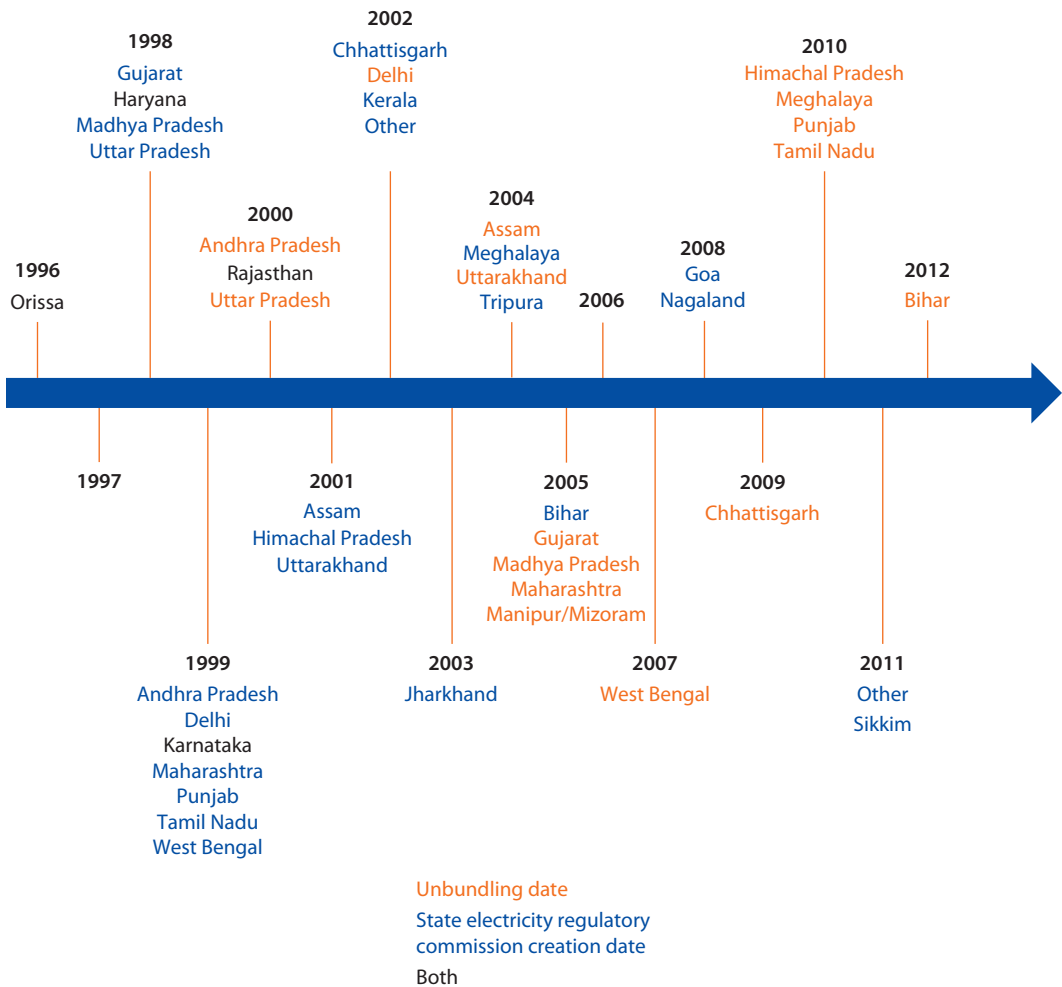
Against this background, in 1996 Orissa became the first state to embrace what was then a new, and bold, power sector restructuring model for India. At the time the Orissa State Electricity Board was the worst performing SEB of any major state. Blackouts and brownouts were common, and only about 20 percent of the state's households were connected to the grid.

Orissa vertically restructured and privatized its power sector—unbundling its SEB into private companies each responsible for one of generation, transmission, or distribution—and created an independent body for regulating and determining tariffs for the electricity sector.³ In many ways the formation of successor utilities, in part through the government's statutory financial and employee transfer schemes, and the creation of the Orissa Electricity Regulatory Commission were significant contributions to the Indian power sector.

As India's economy continued to face crippling power shortages, states started restructuring their SEBs and establishing state electricity regulatory commissions (SERCs) under their own state reform legislative initiatives.⁴ The Electricity Regulatory Commission Act of 1998 set up the Central Electricity Regulatory Commission (CERC) and brought regulatory consistency to the states (figure 1.3).

The government also implemented measures to address the frequent grid disruptions and low voltage that had resulted in suboptimal operations and worsened the quality of service delivery. In 2000 the CERC announced a new system of scheduling and dispatch of power based on an availability-based tariff (ABT). The system was designed to bring about grid discipline and promote scientific settling for contracted sale and purchase of power. The ABT has three charges: a fixed charge; an energy charge linked to day-ahead injection and overdrawal of power; and a penalty—the unscheduled interchange charge—for deviation from day-ahead commitments that could disturb the grid frequency.⁵

Figure 1.3 Timeline of Sector Unbundling and Establishment of Regulatory Commissions



Source: Pargal and Mayer 2013.

The Lead-Up to the Electricity Act of 2003

Despite significant reform and restructuring during the 1990s, state utilities continued to underperform commercially. By 2001/02 power sector commercial losses had risen to about Rs 250 billion (\$6 billion, or 1.5 percent of GDP). Technical and operational indicators had deteriorated, and cost recovery had actually declined. Energy and peak deficits remained substantial despite impressive additions to capacity, because demand growth outstripped growth in supply.⁶

Payment arrears to the central public sector undertakings, such as the National Thermal Power Corporation, Power Grid Corporation of India, and others, mounted. To avoid hurting the creditworthiness of these undertakings, in 2001

an expert committee under the leadership of M.S. Ahluwalia, Deputy Chairman of the Planning Commission, recommended and implemented a bailout plan for the sector. To restore the sector to financial solvency, the bailout converted Rs 350 billion (\$7.4 billion) of debt (outstanding arrears of the SEBs) into state government bonds and waived 50 percent of the interest outstanding. Thus a number of states began 2002/03 with accumulated losses that were lower than in the previous fiscal year: 2002/03 served as the starting point for the reforms that followed.

In 2003 the central government consolidated the piecemeal reforms and state initiatives of the 1990s into the Electricity Act of 2003 (EA 2003, or EA)—a single, progressive, market-oriented framework. The EA 2003 aimed to move the sector toward enhanced competition, accountability, and commercial viability. Several policy measures followed the EA and elaborated on its provisions, including the National Electricity Policy, 2005; the National Tariff Policy, 2006; the Integrated Energy Policy, 2006; and the Hydropower Policy, 2008.

Notable initiatives were the delicensing of thermal generation, the introduction of power trading as a licensed activity, the strong emphasis on competition, the adoption of multiyear tariff frameworks, and the promotion of rural electrification and renewable energy (box 1.1). Most important, the EA was predicated on open access for transmission and distribution with the aim of creating an environment in which generators could sell to the highest bidder and consumers could buy power from the most economical source.⁷

The EA mandated unbundling and corporatizing utilities and establishing independent regulators as steps that would increase utility accountability for performance to external stakeholders, limit state government control, and create internal accountability for results. The EA thus paved the way for a fundamental

Box 1.1 Reform Areas of the Electricity Act of 2003 (and Subsequent Policies): Objectives and Mandates

Introduction of Competition

- *Unbundle state electricity boards.* The distribution, generation, transmission, and dispatch functions are required to be independently operated.
- *Delicense generation.* The requirement for a license from the Central Electricity Authority to build and operate generation plants was removed (except for hydropower projects above a given investment threshold, of Rs 25 billion [\$0.4 billion] as of April 2012; CEA 2012), making it easier for any generation company to enter the market.
- *Move to open access.* The state electricity regulatory commission (SERC) is required to provide notification of nondiscriminatory open access that permits the sale of electricity directly to consumers outside power purchase agreements with distributors, providing choice and network access to power procurers and end-users.

box continues next page

Box 1.1 Reform Areas of the Electricity Act of 2003 (and Subsequent Policies): Objectives and Mandates *(continued)*

- *Introduce power trading.* Specify regulations (such as fixed ceilings on trading margins) to allow trading of electricity. SERCs issue trading licenses for intrastate trade, while interstate trading is licensed by the Central Electricity Regulatory Commission. SERCs also introduce scheduling discipline into this multiseller market by establishing intrastate availability-based tariffs.

Enhanced Accountability and Transparency

- *Establish the SERC.* State power sectors are required to be independent and regulated by SERCs, whose powers and responsibilities include setting tariffs and passing (and in some cases implementing) regulations. SERCs are meant to be independent from the state and central governments, though the center still directs the national electricity and tariff policy.
- *Establish a national Appellate Tribunal.* The central government established this entity to oversee reform implementation throughout the country and address any disputes or appeals against regulators.
- *Corporatize utilities.* Utilities are required to register as corporate entities, thus becoming subject to the requirements of the Companies Act of 1956.

Cost Recovery and Commercial Viability

- *Improve operational efficiency.* State utilities are required to achieve 100 percent metering within two years, adopt stringent measures to deter electricity theft, and reduce cross-subsidies in a phased manner.
- *Ensure competitive procurement.* The National Tariff Policy (2006) specified that distribution licensees should procure long-term power through tariff-based bids under a multiyear tariff framework with a control period of three to five years. Two different procurement modes (Case 1 and Case 2) were developed.
- *Move to cost recovery.* SERCs are required to establish progressive tariff-setting mechanisms to bring tariffs to cost-recovery levels. SERCs should also issue multiyear tariffs to increase pricing certainty.

Access to Electricity and Rural Electrification

- *Ensure universal access.* The Rural Electrification Policy (2006) set an ambitious goal of providing electricity for all by 2009, and required state governments to formulate a Rural Electrification Plan within six months of passing the policy.
- *Affordability and availability.* The Rural Electrification Policy also aimed for quality and reliable power at reasonable rates and provision of a minimum lifeline consumption of 1 kilowatt-hour a day per household by 2012.

Improved Customer Service and Affordability of Supply

- *Reduce losses.* Meet aggregate technical and commercial loss reduction targets set by the SERCs.
- *Establish service standards.* Establish and enforce standards of performance; establish a consumer grievance redressal forum and appoint an ombudsman.

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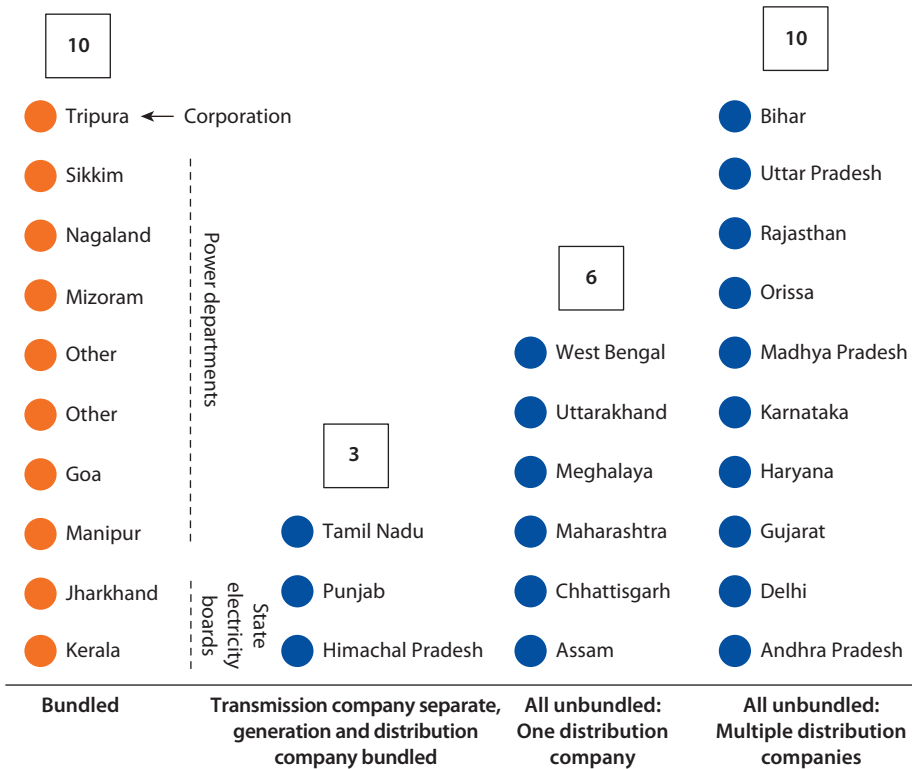
Box 1.1 Reform Areas of the Electricity Act of 2003 (and Subsequent Policies): Objectives and Mandates (continued)

Promotion of Renewable Energy

- *Renewable energy framework.* SERCs are required to specify for the distribution licensee(s) in their states the percentage of the overall purchase of power that must come from renewable sources. This renewable purchase obligation guarantees a minimum proportion of renewable energy in the state’s energy consumption mix.
- *Incentives to promote renewable energy generation and energy efficiency.* This includes notification of regulations on renewable energy and energy efficiency, including feed-in tariffs, time-of-day tariffs, and time-of-day metering.

Source: Khurana and Banerjee 2013.

Figure 1.4 Power Sector Structure by State, 2013



Source: Pargal and Mayer 2013.

alteration in the power sector’s institutional arrangements. As of 2013, 28 regulatory commissions exist, covering all states.⁸ Unbundling has been completed in 19 states, most recently in Bihar (November 2012). The remaining 10 states have a single utility operating either as a corporation, power department, or SEB (figure 1.4).⁹ The unbundled states vary in market structure: 10 have unbundled

into multiple distribution companies (discoms), 6 have unbundled into only one discom, and 3 have separated transmission but kept generation and distribution as one company.

An important milestone has been the development of interstate transmission regulations. A robust transmission system is needed for the seamless flow of electricity across regions and states. The EA has thus mandated the CERC to regulate interstate transmission to serve the emerging needs of competition and a multiple player regime in the sector. In 2010 the CERC introduced the “smart transmission tariff,” a point-of-connection system to replace the regional “postage stamp” method of allocating transmission charges among different users, with the added objective of relieving grid congestion (see appendix A).

Sustainability and energy security have been spotlighted through India’s National Action Plan on Climate Change, released in 2008. The action plan comprises eight national missions to enable progress on various fronts, with several goals relevant to the electricity sector, such as increasing the share of solar energy in the generation mix and raising energy efficiency through industrial energy savings, greater adoption of efficient appliances, and demand-side management.

Notes

1. Much recent work has focused on Africa: Calderón and Servén (2010) report that the quality of and access to electricity services promote growth and reduce inequality in Africa. Andersen and Dalgaard (2013) conclude that power outages have a debilitating impact on an economy, lowering long-run gross domestic product per capita by 2.86 percent in Africa. Further, Dinkelman (2013) presents evidence supporting electrification and employment, suggesting that South Africa’s massive rollout of electrification in rural areas had a positive impact on female employment.
2. SEBs and power departments fulfill similar roles, but an SEB is a government-owned company, while a power department is a department of the state government.
3. The World Bank supported Orissa’s reform process through a \$350 million assistance package.
4. Delhi, Rajasthan, Haryana, Uttar Pradesh, Karnataka, Gujarat, Assam, and Madhya Pradesh adopted state-level legislation to reform their power sectors, with Delhi, notably, succeeding in privatizing distribution. These early cases informed the design of the Electricity Act of 2003.
5. The unscheduled interchange mechanism is part of the short-term market, along with bilateral trading and power exchanges.
6. The share of the power sector in national plan outlays declined, despite rising power sector investments, due to larger government budgets.
7. The EA defines open access as the “nondiscriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulation specified by the Appropriate [electricity regulatory] Commission” (Ministry of Law and Justice 2003).

8. Manipur and Mizoram share a single SERC, as do Goa and the union territories.
9. The EA does not require state power departments to unbundle.

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Impressive Achievements in Many Dimensions

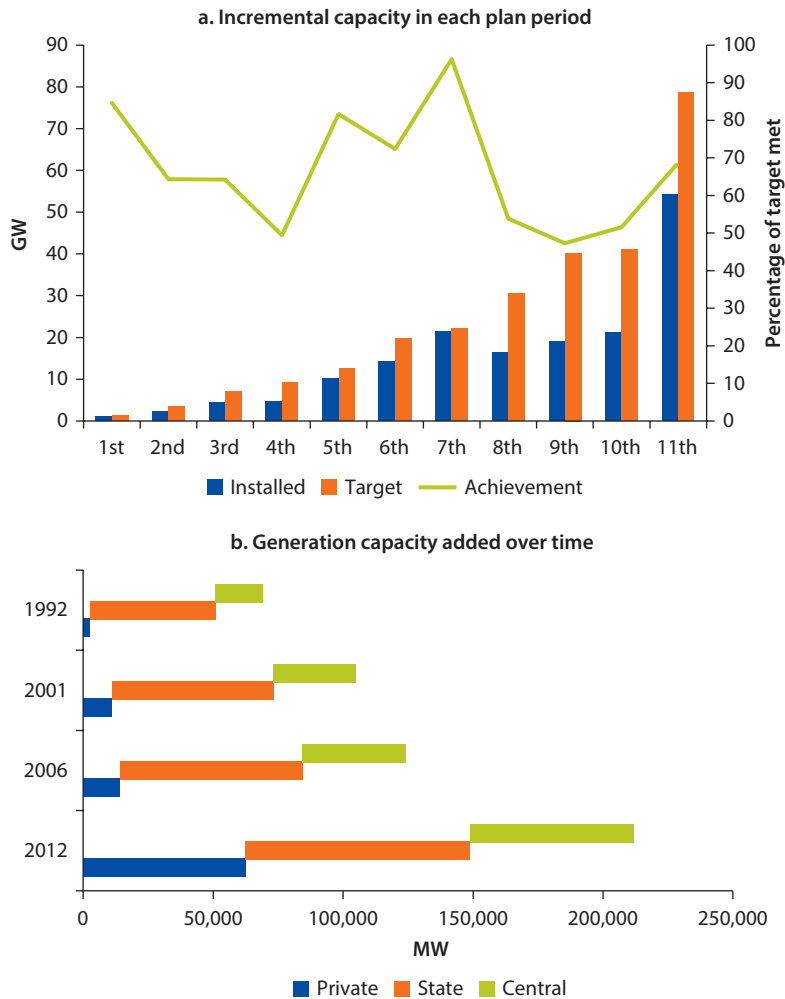
Enabled by the Electricity Act of 2003 (EA 2003, or EA) and a favorable economic environment, India's power sector has progressed immensely since 2003, with major achievements in all segments. And India's successes and experience are likely to be of interest to other developing countries, mainly because its approach has emphasized learning by doing, adaptation, and "localization" of solutions.

Access to electricity expanded rapidly over the last decade, with an emphasis on connecting poor and rural households to the power grid. An ambitious program of capacity development in generation and transmission was implemented and an enabling environment developed for the private sector. A wholesale market for power was created, riding on open access and licensed trading activities. Competitive procurement of new thermal and solar generation capacity was a departure from the prior practice of procurement through memorandums of understanding (MoUs) for thermal power and predetermined feed-in tariffs for solar power. Competition among bidders quickly led to steep price reductions. Distribution, too, saw notable successes through experimentation with innovative models that have improved efficiency and that point to ways to harness the private sector for cutting losses and improving service delivery.

A Tripling of Generation Capacity

The policy focus on ramping up generation capacity to power India's growth took on added emphasis in the 1990s with an amendment to the Electricity Supply Act in 1991 and the introduction in 1995 of the Mega Power Policy. Generation capacity grew threefold between 1992 and 2012. Today, installed capacity stands at 214 gigawatts (GW), making India's the fifth-largest power system in the world after China, the United States, Japan, and the Russian Federation. Recent capacity addition, particularly in the 11th Five-Year Plan (2007–12) at 54 GW, has been the highest in the country's history (figure 2.1), but even then, it was only 69 percent of the 78 GW target set at the beginning

Figure 2.1 Generation Capacity



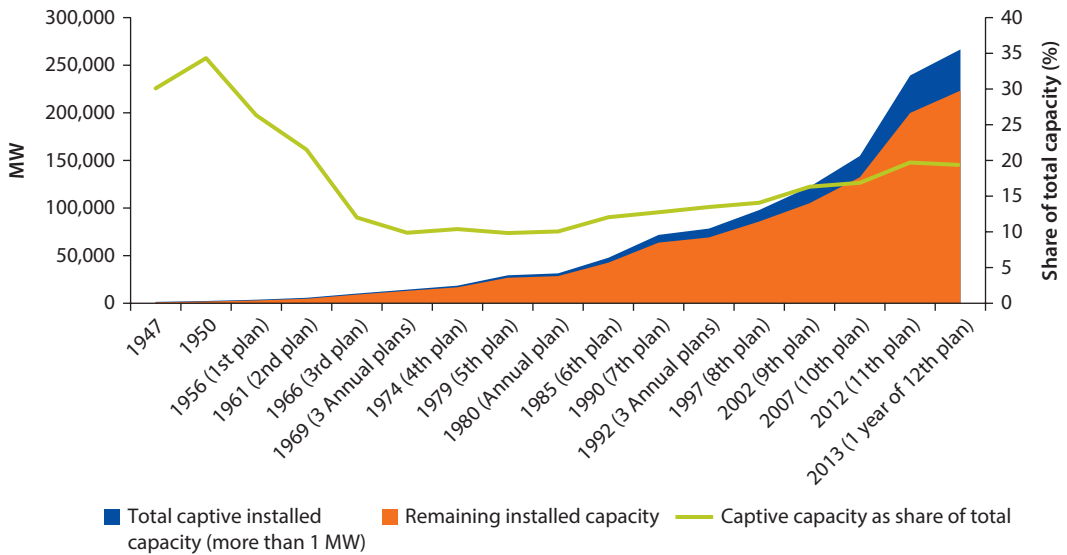
Source: Mukherjee 2013.

of the plan period. The best implementation performance, by far, was in the 7th Plan, when 96 percent of the target was met.

The private sector has emerged as a major driver of generation growth, responsible for installed generation capacity in 1991–92 of 2.5 GW (3 percent of total generating capacity), which grew to 62.5 GW by the end of 2012 (29 percent of the total)—a 17 percent compound annual growth rate. This rate of increase is likely to continue in the near future, given the stock under construction and development. In the 12th Plan (2012–17) the private sector is expected to play an even more important role, contributing half the targeted capacity of 88 GW.

The generation segment has attracted the most interest from private players, largely Indian companies. Over the years a solid private developer base has

Figure 2.2 Captive Generation



Source: CEA 2013.

emerged, including companies already working as engineering, procurement, and construction contractors in the power and infrastructure sectors, as well as companies in other sectors when bidding rules have allowed those without prior experience in the power sector to participate.

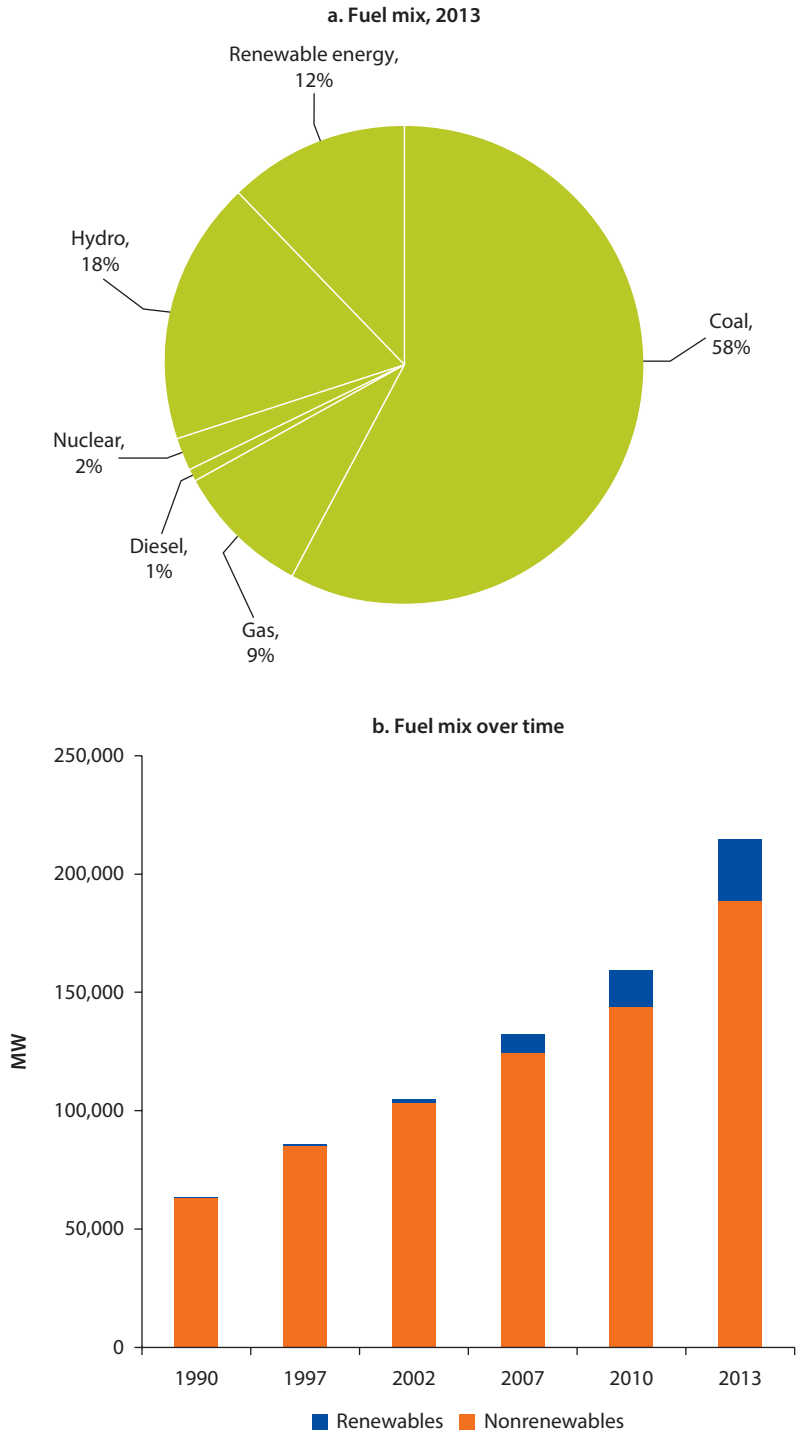
Even then, capacity has been fighting a losing battle against demand—the deficit remains around 10 percent of energy and 12 percent of peak load. One byproduct of this gap has been rising captive generation. As of 2013, India has 43 GW of captive capacity, or 19 percent of total installed capacity (figure 2.2). Growth in captive capacity of 17 GW during the 11th Plan is the highest in any plan period.

Progress toward a Clean Energy Future

Although India’s electricity system remains almost 60 percent coal based, the addition of renewable generation capacity has accelerated over the past two decades for both grid and off-grid generation. In 1990 grid-interactive renewable energy capacity was 18 megawatts (MW)—a miniscule share of the total. In March 2013 it was 25,856 MW—12 percent of the total (figure 2.3).

The growth of grid-based electricity supply from renewables has occurred in two phases. The first started after feed-in tariff guidelines were issued in 1993, and the second after the EA 2003 was enacted. The latter created new market awareness for the potential of supply from renewables, aided regulatory certainty, and formalized and standardized the commercial framework for investors, captive power producers, and independent power producers. Even off-grid renewable energy capacity now stands at a respectable 825 MW.

Figure 2.3 Renewable Energy Capacity



Source: CEA 2013.

On a broader scale the ability of transmission systems to support the ramp-up in generation capacity remains to be seen, as does its adeptness in ensuring evacuation from new renewable energy facilities (see appendix B).

India has immense hydropower potential, but 68 percent of this potential has yet to be fully harnessed. In fact, the share of hydropower in the generation mix has actually dropped from 44 percent in 1970 to about 18 percent in 2012. Only 5.5 GW of hydropower, of a targeted 15.0 GW, was added during the 11th Plan, with most projects delayed three years or more. The 12th Plan ambitiously aims to add 9 GW of hydropower capacity, 28 percent of it by the private sector. A recent report prepared for the World Bank elaborates on the opportunities and challenges in attracting private sector participation to hydropower (Mercados EMI 2012; see appendix C).

The focus on clean energy includes energy efficiency. A major milestone was the Energy Conservation Act of 2001 and its amendment in 2010, which mandated building codes, standards, and labels for appliances and stipulated industry norms. The government estimates that the energy efficiency market has an investment potential of \$10 billion and that improving energy efficiency could save up to 184 billion kilowatt-hours (kWh) and 149 million tons of carbon dioxide in just five years (Delio, Lall, and Singh 2009). Industry is expected to account for more than 25 percent of these estimated savings. Under the Bureau of Energy Efficiency, India became the first developing country to adopt an energy efficiency trading scheme that uses market-based mechanisms (Singh 2013). The largest of these mechanisms was the Perform, Achieve and Trade program, started in 2012. It mandates energy-intensity targets for the most energy-intensive industrial sectors, covering 478 large firms in eight industries and aiming to save an estimated 24 million tons of oil equivalent by 2020, or 6 percent of today's energy consumption.

Bachat Lamp Yojana, another initiative, involves replacing incandescent lamps with subsidized compact fluorescent lamps. The target is to distribute 400 million compact fluorescent lamps for an estimated saving of 6,000 MW. However, the Bachat Lamp Yojana has moved forward only in Andhra Pradesh, Delhi, Karnataka, Kerala, and Punjab, with just Kerala achieving its target (Hector and Anand 2012). The crash of the carbon market has made it difficult to subsidize the initiative under the Clean Development Mechanism.

Creating a National Grid

India's transmission system has come a long way since the mid-1960s when it consisted of five separate regional grids. It was not until the 1998 amendment to the Electricity Supply Act that the basic framework for coordinated planning and development was established and private participation in transmission was allowed. India has since moved toward establishing a nationally synchronized grid to smooth variations in regional demand and supply and building inter-regional links. All five regional grids—Northern, Eastern, Southern, Western, and

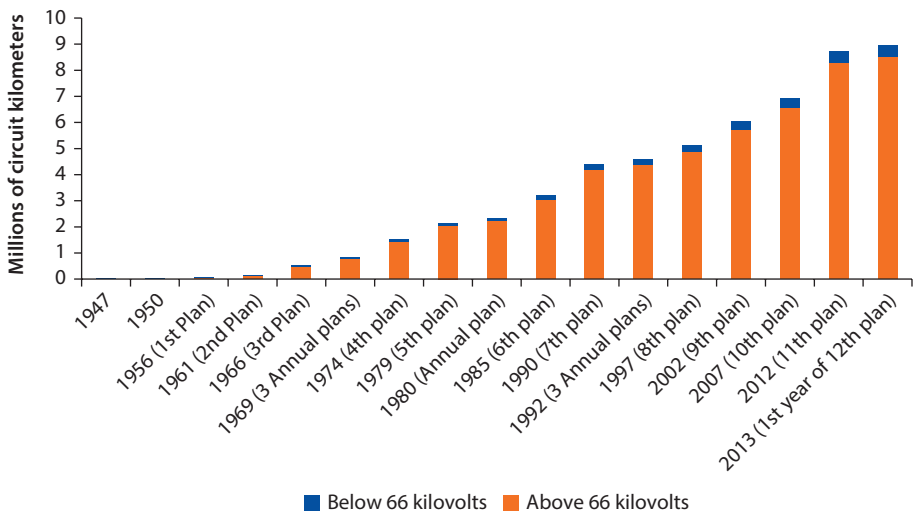
North-Eastern—are now synchronously connected, forming a single grid operating at one frequency.

The Power Grid Corporation of India (PGCIL), the central transmission utility founded in 1992, owns 80 percent of interstate transmission networks while accounting for 95 percent of state transformation capacity. It was also responsible for power management as the National Load Despatch Centre until the Power Systems Operations Corporation, a wholly owned subsidiary, was created to take over this function in 2010. PGCIL now focuses on transmission links. The grid has expanded to nearly 9 million circuit kilometers, overwhelmingly in high-voltage lines (figure 2.4).

The Planning Commission estimates a power demand of 450 GW and total installed capacity of about 600 GW by 2022. To carry this demand, the national grid’s transmission capacity would need to be gradually enhanced to about 150 GW by 2022 (Planning Commission 2006). The target in the 12th Plan is to add 40 GW in transmission capacity (Planning Commission 2013). Currently, 19 GW is under construction—78 percent in the private sector.

Providing relief to the congested transmission grid has been a priority for the Central Electricity Regulatory Commission (CERC), reinforced by the high targets for generation capacity addition in the 11th Plan, which required commensurate evacuation capacity.¹ Accordingly, in 2010 the CERC approved the execution of nine high-capacity power transmission corridors, with a total investment requirement of Rs 580 billion (\$12.7 billion), to be implemented by PGCIL.² The generation projects are either in the coal belt, coastal areas (which would use imported coal), or the areas with hydropower potential in the North-East.

Figure 2.4 Plan-Wise Expansion of Transmission Lines



Source: CEA 2013.

Another CERC intervention during the 11th Plan, to relieve congestion in the grid, was framing regulations on point-of-connection transmission charges. This move sought to introduce a scientific approach to determining transmission tariffs based on distance, direction, and power flow, and correct the shortcomings of the previous postage stamp method (see appendix A). The new approach reduces uncertainty facing private investors by providing for formula-based transmission charges that can be calculated in advance.

The CERC is also working to ensure safe and secure operation of the grid through amendments in the Indian Electricity Grid Code and unscheduled interchange (UI) regulations. The schedule of drawal and injection to the grid is determined by the system operator or load dispatcher. Under the availability-based tariff mechanism, any deviation from the schedule is paid through UI charges. UI accounts are issued weekly, and per UI regulations, payment of UI charges has high priority. Overdrawing distribution companies (discoms) are required to remit the UI payable amount into a regional pool account operated by the Regional Load Despatch Centre within 10 days after the bill is issued. Observing that nonpayment of UI charges amounts to extracting energy from the grid without paying for it,³ the CERC has taken action against many defaulting entities.⁴ Overdrawal as a means of meeting short-term spikes in demand is particularly problematic when overall demand is high and frequencies low. The permissible frequency range has been tightened (from 49.2 hertz to 49.5 hertz), and UI charges have been increased to further deter deviation from the schedule. These efforts aim to get the discoms to plan for power procurement rather than depend on UI to meet their short-term needs for power.

Despite these initiatives, India's grid came under heavy scrutiny during the massive blackouts of July 2012 that affected 600 million people. The Enquiry Committee, established by the Ministry of Power, pointed to weak interregional corridors due to multiple outages, overdrawal by some northern region utilities, and high loading on and loss of a specific 400 kilovolt link as contributing to the shutdown (CERC 2012). Further, the CERC noted that transmission congestion also constrains the volume of electricity that can be transacted through power exchanges. Had there been no congestion in the system, the actual volume transacted could have been about 17 percent higher over 2012–13 (CERC 2013).

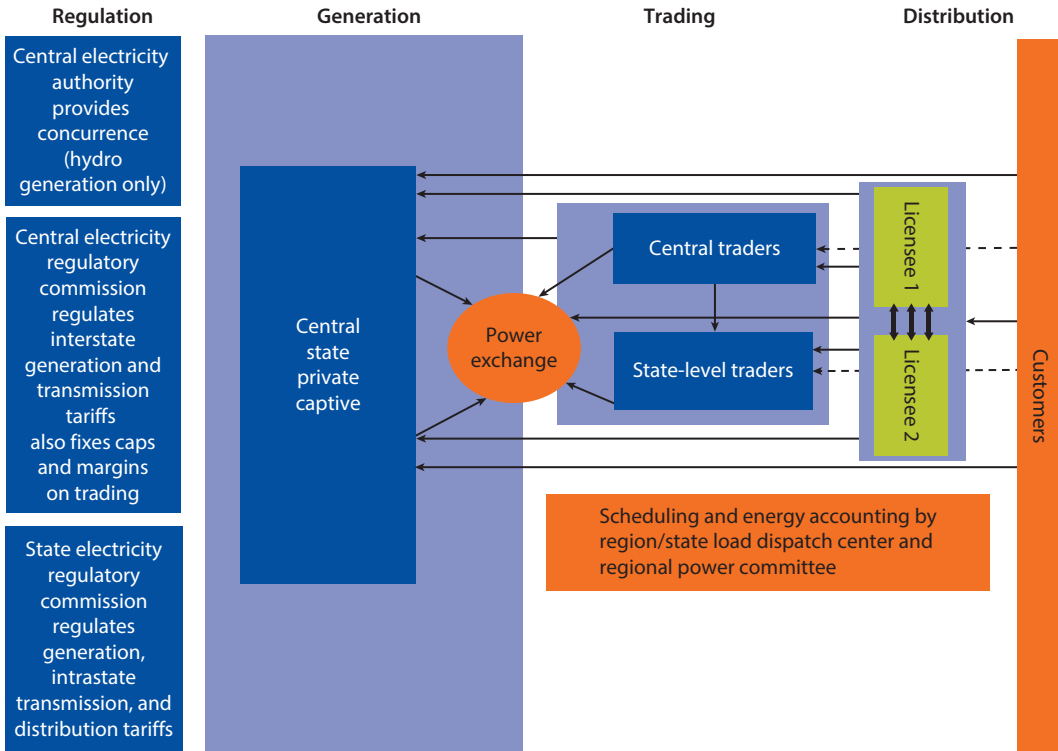
The government still dominates the transmission segment, but efforts are under way to attract greater private sector participation. The first transmission line with private investment was built in 2006—the Indo-Bhutan power transmission line, a joint venture between Tata Power and PGCIL. The segment is moving forward on private sector participation with seven central and four state projects currently under way. With the recent notification of the Ministry of Power on mandatory procurement of transmission services through competitive bidding, more projects are expected to be awarded through private sector participation (see appendixes D and F). And states—Maharashtra, for instance—are also conducting innovative experiments to improve project management and procurement planning for transmission projects (see appendix E).

Developing Competitive Power Markets

The EA 2003 has moved the power sector toward its vision of a competitive market with multiple buyers and sellers, starting with a multiseller model at the wholesale end, mandating open access to consumers above 1 MW, and making trading a licensed activity (figure 2.5). There has been an attempt to introduce multiple players at each point in the sector value chain. When the EA delicensed generation—allowing free entry and removing restrictions on setting up captive power plants—the market blossomed. The EA opened space for multiple licenses and private participation in transmission. And by ensuring that the transmission utility was prohibited from generating or trading, it strove to ensure efficiency and avoid conflicts of interest in power dispatch. The EA allows for choice at the consumer end by permitting multiple distribution licenses (even for parallel lines). The key premise is that with nondiscriminatory open access, any licensee should be able to serve any consumer, if necessary using the state utility’s distribution lines by paying a wheeling charge (see appendix G).

While trading power predated the EA, the recognition of trading as a licensed activity has helped establish power exchanges. Anyone who qualifies under eligibility criteria of the state electricity regulatory commissions (SERCs) can be

Figure 2.5 Industry Structure after 2003



Source: Mercados EMI 2013.

a trader. Allowing third-party sales and trading electricity in bulk were novel concepts that the EA introduced (Bhattacharyya 2005; Thakur 2005).

At the same time, the use of the frequency-linked UI mechanism to balance the market has created a wholesale transaction platform. By 2005–06 the short-term market had matured enough that trading was taking place both directly and through licensed traders among distribution licensees. The CERC has further promoted the development of trading through two power exchanges that introduced an electronic online power market. In 2008 the Indian Energy Exchange, a state-of-the-art energy trading, auction, and bidding platform, went live. And the CERC also authorized the Power Exchange India Ltd., which began operating in 2009. Even though the volume traded on the exchanges as a share of total flows is not very large—about 11 percent of total electricity generated in 2012—prices from exchange trades have been important in sector reforms and investment signaling (figure 2.6).

The benefits of open access to the transmission network are now also becoming apparent. More than 160 (largely industrial) end-consumers are reported to be buying power from power exchanges relying on open access. Captive power plants have also been selling surplus power through the exchanges. Thus much latent capacity has come into the market, increasing the availability of power and deepening the market (CERC 2010).

The CERC has also promoted competitive markets in renewable energy through the renewable energy certificate mechanism. While these are still early days, renewable energy certificates have generally been acknowledged as a positive market development. The wide difference between the volume of buy and sell bids of renewable energy certificates placed through power exchanges suggests more demand for solar renewable energy certificates and less for non-solar renewable energy certificates. A recent glut in the market with sellers outnumbering buyers has caused prices to tumble (Renewable Energy World 2013).

Figure 2.6 Short-Term Market for Electricity

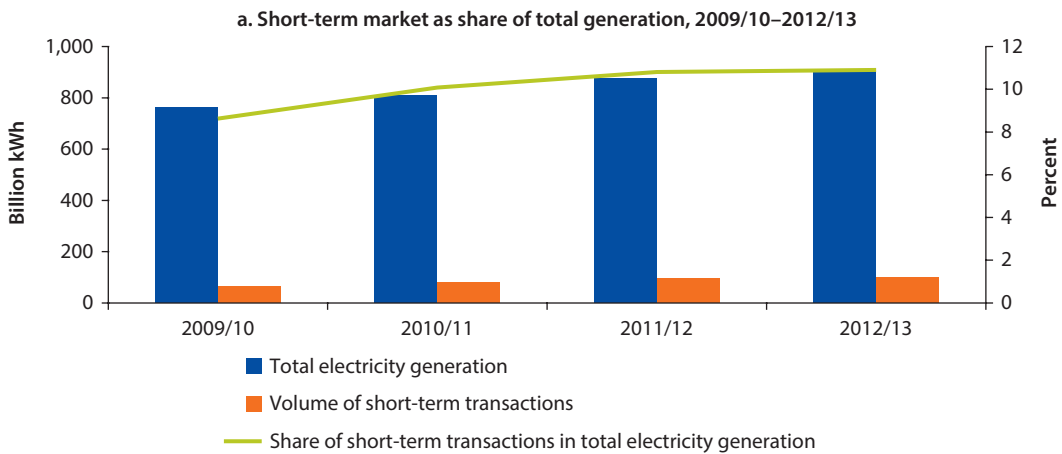
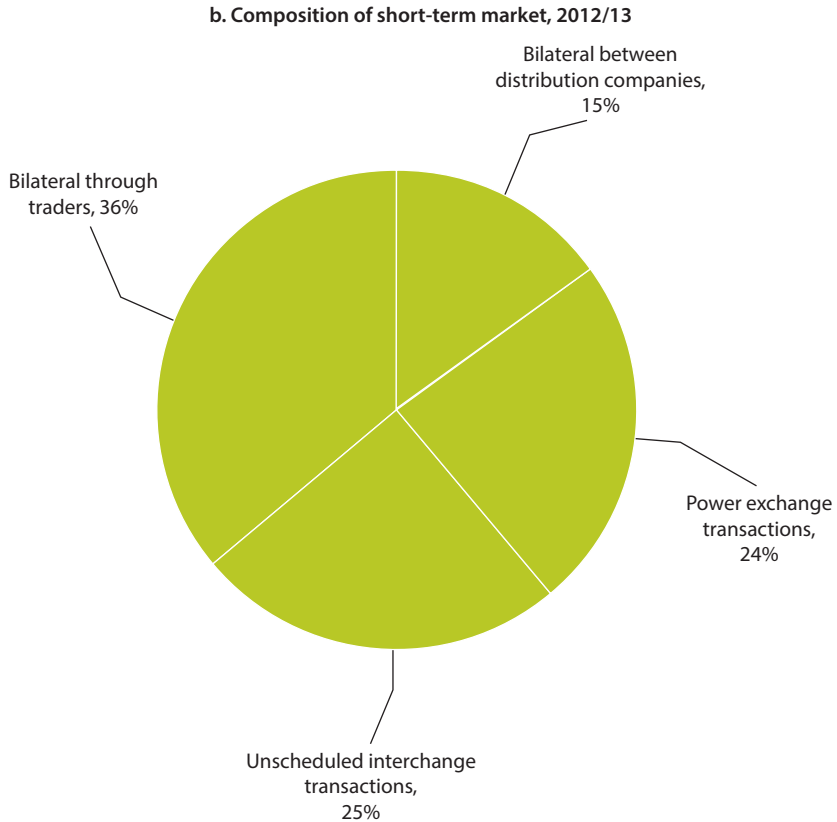


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Figure 2.6 Short-Term Market for Electricity (continued)

Source: CERC 2013.

Competitive Power Procurement

Thermal Capacity Addition

In 2005 the government issued tariff-based competitive-bidding guidelines under Section 63 of the EA 2003 to create competition in generation and to help reduce the cost of supplied power. Earlier, discoms (and state electricity boards) had purchased power under negotiated contracts or MoUs with independent power producers, ensuring the producers a 16 percent return on equity. Now, competitive bidding became the norm for medium-term procurement (one to seven years) and long-term procurement (seven years and more) of base-load, peak-load, and seasonal power requirements.

For ultra-mega power plants (UMPPs) with a capacity of at least 4,000 MW, India adopted a novel approach. The Power Finance Corporation was appointed the nodal agency to conduct the competitive bidding for selecting a developer for each project through tariff-based competitive bidding. Twelve proposed UMPPs were identified, of which four projects were awarded to developers based on a two-stage competitive-bidding process. The private sector's response

to UMPP projects has been excellent, both in participating and in bringing down the overall tariff. Reliance Power has won major UMPP projects, with Sasan UMPP having the lowest bid of all (Rs 1.19/kWh, \$0.025/kWh), while the highest bid was for the imported-coal-fueled Mundra UMPP (Rs 2.26/kWh, \$0.048/kWh).

Apart from UMPPs, two routes are open for competitive procurement of power by discoms—Case 1 and Case 2, depending on whether the state utility procuring the power also specifies the location of the plant and the fuel source.⁵ The bidder takes on greater risk under Case 1 because the responsibility for technology, fuel, and land, as well as necessary clearances, is retained, unlike under Case 2. As expected, Case 2 bids have generally been lower than Case 1 bids. Almost 20 GW of thermal power has been procured through the Case 1 route (though only two Case 1 projects have so far been commissioned). Gujarat and Maharashtra are the leading states, having procured 5.8 GW and 5.1 GW of power, respectively, over 2007–10. Seven state bids have been made for power procurement through the Case 2 route, at 10.4 GW of power procured. The major procuring states under Case 2 are Uttar Pradesh (4.5 GW) and Punjab (3.3 GW).

In 2011 the CERC issued statutory advice to initiate the transition of public sector projects to tariff-based competitive bidding. Before deciding, it carried out a detailed exercise comparing the tariffs from competitively bid projects with those from a hypothetical equivalent plant contracted under a MoU and operating at the same efficiency as a National Thermal Power Corporation plant (CERC 2010). In most cases the competitively bid Case 1 tariff was much lower than the tariff that would have come in under the MoU. For Case 2 bids all the competitively bid tariffs were far lower than under the MoU.

The steep rise in fuel (imported coal) prices starting in 2011/12 brought to the fore key weaknesses of competitive procurement. In hindsight, bidders alone were never going to be able to assume fuel (particularly coal) price risks fully, and a more balanced risk allocation ought to have been put in place. Celebrations about competitively bid tariffs emerging around Rs 1.50 (\$0.03) per kWh were premature, as these very contracts are now seeking regulatory relief to retroactively adopt a pass-through clause for fuel costs. The government is amending the standard-bidding documents for Case 2 power procurement, asking bidders to quote only the capacity charge for a station heat rate of 2,300 kilocalories per unit (which will be verified by an independent engineer), and allowing all other charges to be passed through. This shared-risk approach is believed to put a lower burden on consumers than the previous model.

Thermal capacity addition has been handicapped by a lack of coordination between the ministries of coal and power. There are large gaps between the required (for plants commissioned during the 11th plan that had been awarded domestic coal linkages by Coal India) and the available coal supply. Coal India's inability to supply the amount required implies a need to review and re-optimize the allocation of coal linkages and rely on imports in the interim. In July 2012, Coal India reported plans to import up to 30 million metric tons of coal to meet

rising domestic demand and to mitigate power shortages. As imported coal is far more expensive than domestic coal, the government has been considering the use of a pooled price as an option to cushion the shock.⁶

Also, delivering coal to the purchasing plants requires considerable logistical capability and planning, such that the supply and pricing of coal for power plants is hurt by constraints or inefficiencies in the transport sector. The Industrial Management Department of the State Economic and Trade Commission in China is a good example of an institutional setup that coordinates the coal, rail, and electricity sectors (see appendix H).

Solar-Based Capacity Addition

The National Solar Mission, launched in January 2010, set a target of installing 20 GW of grid-connected solar power by 2022, carried out in three phases (table 2.1). Qualifying projects, sourced from private investors, are selected through a reverse auction procurement mechanism, and are technology neutral, employing either solar photovoltaic or solar thermal technology. In 2010 India's solar energy market was 17.8 MW; by March 2013 capacity had grown to 1,440 MW, of which around 513 MW was commissioned under the Mission and other central government programs. Another 825 MW was deployed under state initiatives.

In Phase 1 the central government conducted two batches of reverse auctions as a price discovery mechanism, offering feed-in tariffs and long-term power purchase agreements to the selected least-cost developers.⁷ Complementing the feed-in tariffs to developers is support to discoms through the bundling of solar power with thermal power, reducing the average per unit cost of solar power.

Eight states have participated in Phase 1 installations, with Rajasthan by far in the lead. Phase 1 also attracted large conglomerates and new players to the solar market: more than 500 bidders competed for 63 projects in the two batches. A total of 140 MW was allocated to 28 solar photovoltaic projects and nearly 470 MW to seven solar thermal projects. The government also "migrated" existing solar projects, which had been awarded the much higher, administratively determined feed-in tariff, to count toward the National Solar Mission's targets. These projects thus enjoyed a "premium" tariff of Rs 17.91/kWh (\$0.45/kWh) and provided an additional 84 MW of migrated capacity toward

Table 2.1 National Solar Mission Targets, 2010–22

<i>Solar technology</i>	<i>Phase 1 (2010–13)</i>	<i>Phase 2 (2013–17)</i>	<i>Phase 3 (2017–22)</i>
Grid connected/rooftop	1,000–2,000 MW	4,000–10,000 MW	20,000 MW
Off-grid solar applications	200 MW	1,000 MW	2,000 MW
Solar hot water collectors	7 million sq. meters	15 million sq. meters	20 million sq. meters
Rural solar lanterns/lighting	n.a.	n.a.	20 million systems

Source: Mukherjee 2013.

Note: n.a. = not applicable.

the overall Mission targets. As the lowest bid price was Rs 12/kWh (\$0.32/kWh), the migrated projects cost the government an additional Rs 5 (\$0.10) per kWh relative to price discovery through the bidding process. Making headlines in late 2011, competitive bidding for the Mission's second batch of projects in Phase 1 drove down prices for grid-connected solar energy to as low as Rs 7.49 (\$0.15) per kWh, approaching grid parity with fossil-fuel-powered electricity.

Massive Expansion of Access

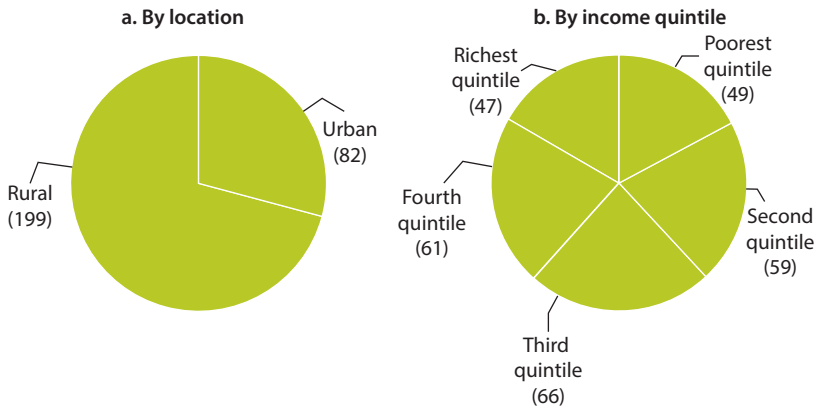
Since the late 1960s India has prioritized electrification through the Rural Electrification Corporation (REC) and new funding initiatives. Under each five-year plan the government has strived to ensure appreciable investments in electrification through appropriate national initiatives and programs. In 2004 it announced a goal of universal electricity access within the following five years as part of the National Electricity Policy. Progress toward these goals gained momentum with the 2005 launch of a flagship program, the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), consolidating all ongoing rural electrification programs. The Ministry of Power retained the REC as the nodal agency for implementing RGGVY, while the Rural Electrification Policy of 2006 laid out the guidelines, definitions, and institutional structure of RGGVY.

RGGVY aims to create a rural electricity backbone, electrifying all villages and habitations of more than 100 people, installing small generators and distribution networks where extending the grid is not cost-effective, and providing free electricity connections to households below the poverty line. India has spent almost Rs 50 billion (around \$1 billion) a year on RGGVY since its inception, and the program is now continuing into the 12th Plan. Today, 92 percent of villages are connected to the electric grid, and the goal is to be close to universal village electrification by 2017.

The program's performance in expanding connections has been impressive. The electrification rate rose 15 percentage points in 10 years to 74 percent in 2010. New consumers were mainly in rural areas, where electricity access rates jumped 18 percentage points to 66 percent. About 28 million people a year started to use electricity over the decade (2000–10). Of these new users, 70 percent live in rural areas (figure 2.7a) and the gains were distributed fairly evenly across the income ladder (figure 2.7b).

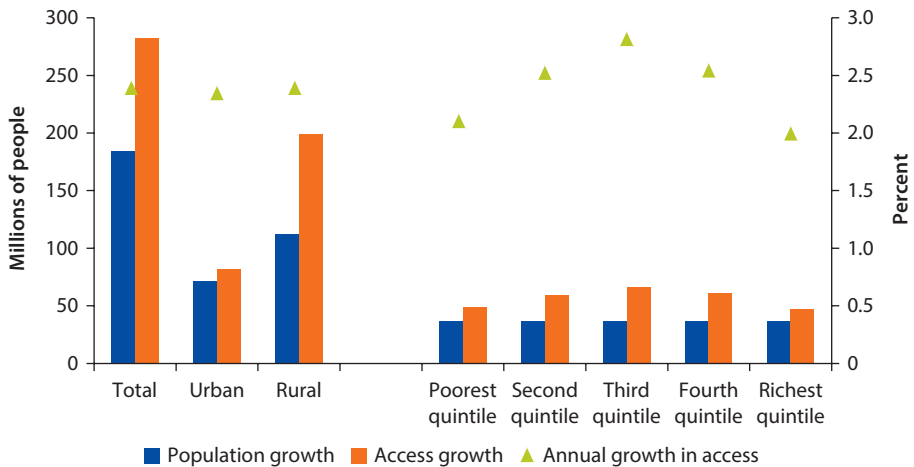
The growth in the electrification rate was moderated by an annual population increase of about 1.5 percent during the decade: about 65 percent of the incremental increase in access was just to keep up with population growth. But India still added 99 million electricity users above the population increase, and the access rate rose by 2.4 percent of the population each year over the period. This growth rate was similar across geographic areas and income quintiles (figure 2.8). In most states the electrified population grew 2–4 percent annually. Access growth in the large states of Uttar Pradesh and Bihar was the lowest among all states, at just about 1 percent, below the rate of population growth.

Figure 2.7 Number of People Gaining Access, 2000–10



Source: Banerjee and others 2013.
 Note: Numbers in parentheses are number of people (in millions).

Figure 2.8 Growth of Access and Population, 2000–10



Source: Banerjee and others 2013.

As a result the absolute numbers of nonelectrified people in these states increased in 2000–10.

Despite this huge increase in electrification, India is home to the world’s largest access deficit. The rural and poorest consumers constitute the bulk of India’s 311 million people without electricity. About 93 percent of India’s nonelectrified population—289 million people—lives in rural areas. More than two-thirds of the nonelectrified population is also among the poorest 40 percent of the population, depending on alternative lighting fuels, primarily kerosene and candles, which have potentially harmful safety, environmental, and health effects.

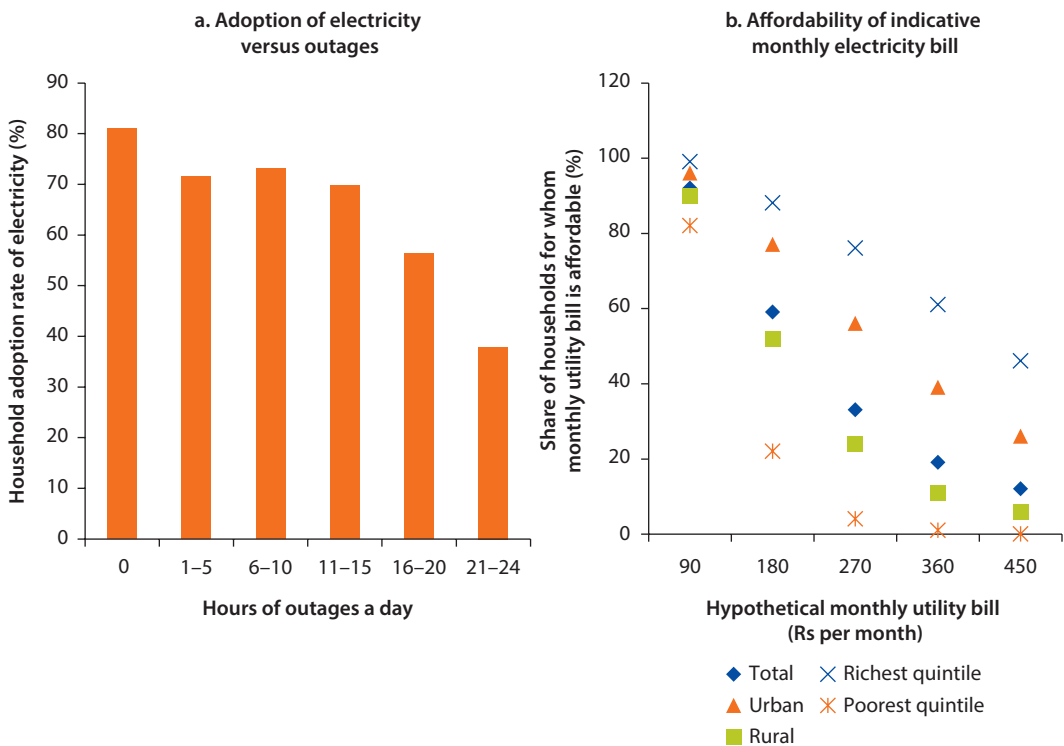
The overall electrification rate, 74 percent, trails the village electrification rate, 92 percent. Disaggregation of this gap suggests that both demand- and supply-side

factors are important in rural areas compared with only demand-side factors in urban areas. While RGGVY is working toward making electricity available to the entire population by 2017, the poor quality of electricity available and the inability to pay can cause households to choose not to connect to electricity—even when it is available. Rural electricity service is generally unreliable, with three-fourths of rural households facing outages of up to four hours a day. This means continued use of kerosene even for electrified households—70 percent also use kerosene for lighting.

There is also a direct correlation between the frequency and duration of power outages and the rate of household adoption of grid electricity in a community. Communities with a service outage of 21 hours a day or more in 2005 had an adoption rate of just 38 percent, against more than 80 percent for those with few or no outages (figure 2.9a).

The affordability of a subsistence level of electricity consumption appears to be less of an issue.⁸ In 2010 about 90 percent of rural consumers and 82 percent of the poorest income quintile could afford to pay Rs 90 (\$2) a month for electricity, which is typically what the connected population in the lowest quintile pays.

Figure 2.9 Affordability and Reliability of Electricity



Source: Banerjee and others 2013.

Note: 0 (no outage) = 3.4 percent of villages; 1-5 = 19.3 percent of villages, 6-10 = 26.2 percent of villages, 11-15 = 23.7 percent of villages, 16-20 = 25.0 percent of villages, and 21-24 = 2.4 percent of villages.

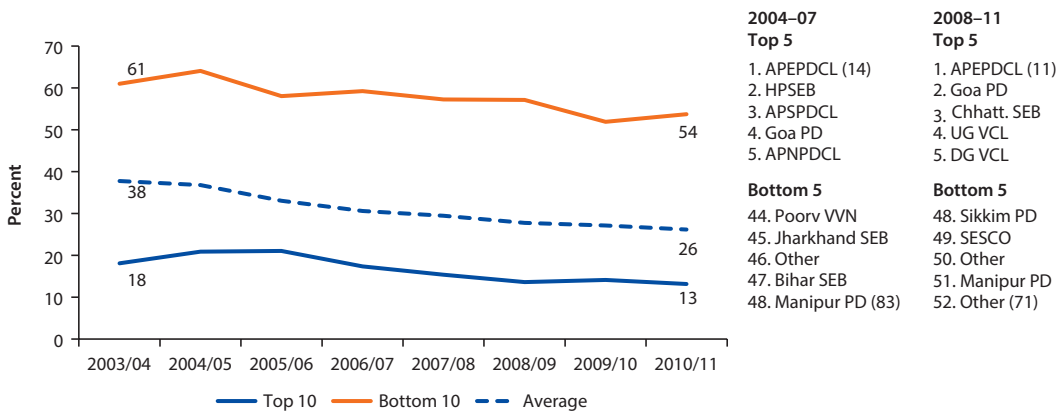
Affordability precipitously declines at Rs 180 (\$3.90) a month—only 22 percent of the poorest consumers and 52 percent of rural consumers could afford this (figure 2.9b).

Promising Examples in Distribution

Distribution has always struggled with inefficiencies. The central government introduced a major investment initiative in 2000/01, the Accelerated Power Development Programme, to improve efficiency in distribution. This was followed in 2003 by a more incentive-based program—the Accelerated Power Development and Reform Programme (APDRP). For the 11th Plan, APDRP’s terms were revised to create a potentially transformative centrally sponsored program—the Restructured APDRP (R-APDRP)—with a total outlay of Rs 515 billion (\$11 billion). The R-APDRP aimed to restore the commercial viability of the distribution sector by putting in place appropriate mechanisms to reduce aggregate technical and commercial (AT&C) losses to 15 percent. The states reporting AT&C losses higher than 30 percent were expected to reduce them at 3 percent a year, and those with less than 30 percent at 1.5 percent a year.

States did report a decline in AT&C losses over time to about 26 percent in 2011 (figure 2.10). The top 10 states’ achievement is impressive, with AT&C losses dropping from an average of 18 to 13 percent. The bottom 10’s performance has improved as well, but remains high at 54 percent. Thus more than half the energy supplied in these states is not being paid for. AT&C losses comprise losses from collection deficiencies and losses in distribution due to technical and commercial (including theft) factors. Innovative (and traditional) measures to reduce theft are being used in different states to reduce overall losses (see appendix I).

Figure 2.10 AT&C Losses, 2003/04–2010/11—Best and Worst Performers by State



Source: Khurana and Banerjee 2013.
 Note: AT&C = aggregate technical and commercial.

Promising models to obtain efficiencies from private participation in distribution have been developed and introduced. The “legacy” private distribution utilities in Kolkata, Mumbai, Surat, and Ahmedabad, with their exemplary performance in efficiency and customer service, have also been recognized as examples of the possible gains from private participation.⁹ However, private participation in distribution has seen only limited action in urban areas.

The EA helped widely legitimize the “distribution franchise” (DF) concept, as it allowed for the appointment of any person to undertake distribution and supply on behalf of the licensee (the state distribution utility) within the licensee’s area of supply. Maharashtra, driven by distribution losses in some areas, was the first to test the input-based franchise route in the Bhiwandi area (box 2.1), where success prompted other states to adopt similar models. DFs in Agra and Kanpur (in Uttar Pradesh) and in Nagpur, Aurangabad, and Jalgaon (in Maharashtra) have since been awarded to bidders.

Box 2.1 The Bhiwandi and Agra Distribution Franchises: A Success Story

The Bhiwandi distribution franchise (DF), run by Torrent Power, completed six years of operation in January 2013. Based on an input-based 10-year DF agreement with the Maharashtra distribution company, it is responsible for metering, billing, revenue collection, and capital expenditures. The expenditures, subject to regulatory approval, are jointly verified by the distribution company and franchisee.

Bhiwandi, a textile hub in Maharashtra, was reeling under a severe power shortage in 2007, with no investment in system upgrades, inadequate metering, low collection, and high losses (table B2.1.1). Due to inaccurate aggregate technical and commercial (AT&C) loss figures, the bid for a DF could not even be based on loss reduction targets, as is standard for DFs. The franchisee was also not subject to a minimum capital expenditure/investment commitment.

Table B2.1.1 Progress in Bhiwandi’s Power Sector over 2006–11

<i>Parameters</i>	<i>2006/07</i>	<i>2010/11</i>
AT&C losses (%)	58.0	18.5
Number of transformers	2,254	2,611
Distribution transformer failure rate (%)	42	3
Metering (%)	23	98
Load-shedding (hours/day)	10–12	—
Collection efficiency (%)	58	99
Megavolt-amperes of reactive power installed	0	160
Number of feeders	46	86
Extra high voltage capacity	550	1,000
Customers	174,000	235,000
Use of information technology	None	SCADA, AMR

Source: Mukherjee 2013.

Note: AMR = automated meter reading; AT&C = aggregate technical and commercial; SCADA = supervisory control and data acquisition; — = not available.

box continues next page

Box 2.1 The Bhiwandi and Agra Distribution Franchises: A Success Story *(continued)*

Since 2006 Bhiwandi has made notable progress. The franchisee reduced technical losses by revamping the low-tension network, maintenance and addition of high-tension networks, and reactive power management. It introduced information technology applications, such as supervisory control and data acquisition (SCADA) and automated meter reading. It regularized 38,000 unauthorized connections, particularly in slum areas, and provided 17,000 new connections. It replaced more than 80 percent of old meters with electronic meters, opened two new customer service centers, and introduced a 24/7 call center and mobile van to decrease complaint-resolution times. By 2013 AT&C losses had fallen to 16 percent, the distribution transformer failure rate was 1 percent, and metering had increased to 99 percent. There is no longer any load-shedding.

In 2009 Torrent Power was selected as the franchisee for the Agra urban area in Uttar Pradesh. As in Bhiwandi, franchisee selection was based on the price bid for input energy (to be paid to the distribution utility for power supplied by it to the franchisee). Uttar Pradesh's distribution sector is extremely inefficient, with high AT&C losses and daily power cuts. The entire distribution network is riddled with theft and pilferage, pervasive illegal connections, inadequate metering, low collection efficiency, and an aging network. At the time Torrent Power was awarded the DF, Agra's network suffered from inadequate investment and lack of maintenance over many years. The city had frequent and widespread power cuts, and the utility was known for poor customer service.

Torrent Power took over operations as a complete transfer in 2010. Poor record keeping by the incumbent utility meant almost no technical and commercial information was available, forcing Torrent Power to reconstruct circuit diagrams and re-create system maps. This permitted systemwide real-time information collection on electricity supply (through SCADA) and faster fault identification and restoration. Torrent Power also invested heavily in substations, moved the low-tension network underground, and established 24/7 customer service centers. Despite strong opposition, illegal connections were disconnected and new methods of revenue collection, such as online payment and mobile vans, introduced. The operational efficiency of the utility improved considerably between 2010 and 2013. The failure rate of distribution transformers fell from 31 percent to 4 percent, metering rose from 23 percent to 98 percent, and AT&C losses dropped from 70 percent to 41 percent. A promising first few years.

Source: Mukherjee 2013.

The urban DF model is structured so that the successful bidder offers maximum efficiency improvement (loss reduction, cost optimization, and so forth) at tariff rates set by the SERC. The model ensures that the front-loaded capital spending required is fully recovered from the incremental revenues generated by the franchisee. None of this burden for increased upfront investment is passed on to the licensee. Therefore, the utility must carefully identify potential areas for implementing DFs. So far, heavily populated areas, requiring an energy input of around 500 million kWh and above, with high losses have been the

most successful. Prospective bidders generally see low-load areas requiring low energy input as unattractive, and the DF process for most such areas has been cancelled by the distribution utilities.

While the competitive-bidding mechanism for appointing a franchisee ensures that the intended efficiency benefits are passed on to the licensee, licensees have started to put additional clauses in such agreements, giving specific targets to the franchisee on AT&C losses, minimum capital investment, metering levels, and call center and complaint management systems. But this “micromanagement” by the licensee may dampen the enthusiasm of participants in later bidding rounds.

In rural areas, private participation remains nascent. A decisive push toward rural franchises was achieved because of their inclusion in the RGGVY program—rural franchises are to ensure revenue sustainability and to help state utilities in managing rural distribution networks that have expanded hugely under the program. In fact, utilities in rural areas need and welcome the franchises, primarily as an instrument to help the utility with metering, billing, and collection. The approach creates scope for involving village or town intermediaries as partners in metering, billing, and collection as well as in operation and maintenance, in cases where the required numbers of skilled workers and community structures are available.

More than 37,000 rural franchises are operating, covering more than 216,000 villages across 18 states. Most of these franchises are collection based, where the franchisee either takes a part of the revenue or earns an incentive up to a preset collection-efficiency target, depending on the contract. Contracts are usually annual with flexibility to grant extensions. There is also a group of “input-based” franchises, where the franchisee buys the energy input in the franchise area, and then resells it to consumers (similar to the input-based model used for some urban DFs). About 1,600 rural franchises are input based, the most notable being the single point power supply system, which sells power to consumers at tariffs approved by the SERC and pays a fixed fee to the distribution licensee. Rural franchisees have yet to invest in the network.

Notes

1. Congested transmission lines hurt not only generators but also the retail customers at the distribution end of the value chain. Because wholesale power purchasers typically seek to buy the least expensive electricity, if transmission constraints frequently limit the amount of electricity that can be delivered into an area where demand is high, the power purchasers (distribution companies) must buy more often from higher cost (spot market) suppliers, and the result is higher electricity costs for consumers. When there is very severe congestion, transmission constraints can also impair grid reliability by reducing the diversity of available electricity supplies and by rendering the area more vulnerable to unanticipated outages of major generators or transmission lines.
2. The nine high-capacity power transmission corridors (HCPTCs) are HCPTC I (Transmission System Associated with Phase I Generation Projects in Orissa) for Rs 87.53 billion (\$1.9 billion); HCPTC II (Transmission System Associated with independent power producer [IPP] projects in Jharkhand), Rs 57 billion (\$1.2 billion);

HCPTC III (Transmission System Associated with IPP projects in Sikkim), Rs 13 billion (\$0.03 billion); HCPTC IV (Transmission System Associated with IPP projects in Bilaspur complex, Chhattisgarh, and IPPs in Madhya Pradesh), Rs 12.43 billion (\$0.26 billion); HCPTC V (Transmission System Associated with IPP projects in Chhattisgarh), Rs 288 billion (\$6 billion); HCPTC VI (Transmission System Associated with IPP projects in Krishnapatnam Area, Andhra Pradesh), Rs 20 billion (\$0.4 billion); HCPTC VII (Transmission System Associated with IPP projects in Tuticorin Area, Andhra Pradesh), Rs 23 billion (\$0.5 billion); HCPTC VIII (Transmission System Associated with IPP projects in Srikakulam Area, Andhra Pradesh), Rs 29 billion (\$0.62 billion); and HCPTC IX (Transmission System Associated with IPP projects in Southern Region for transfer of power to other regions), Rs 48 billion (\$1 billion; CERC 2012).

3. Many discoms lost their planning function after unbundling. Without the benefit of demand-growth analysis or load-flow studies, they cannot submit long-term power procurement plans to the state regulator for approval and simply overdraw when the need arises.
4. The system operator does not have the authority to immediately disconnect any discom seen to be engaging in overdrawal.
5. Case 1 is an open-bidding system in which the developer chooses its own fuel, location, and technology and bids to generate and supply a specific amount of power. In Case 2 the central or state government specifies the fuel and location, and the developers bid based on those specifications. See chapter 2 of Mukherjee (2013) for more details.
6. As the imported coal price would be based on gross calorific value, per international trading practice, and the domestic coal price would be based on useful heat value, it can be assumed that a combined or pooled price would be higher than the current price that thermal power plants pay for domestic coal.
7. Reverse auctions have two main benefits. First, they allow government procurers to select projects based on the lowest cost; second, they ensure that a price-based selection process is fair and transparent.
8. Affordability is defined as the ability to pay a monthly electricity bill that is less than 5 percent of household income.
9. These utilities and a few others were originally set up under private ownership around the start of the 20th century and have remained privately managed ever since. They buy power from state-owned generators, with few exceptions (for example, Tata in Mumbai is a private discom and has its own generation facility). Legacy private power companies are well managed but are few, predating the reforms discussed in this report by almost a century.

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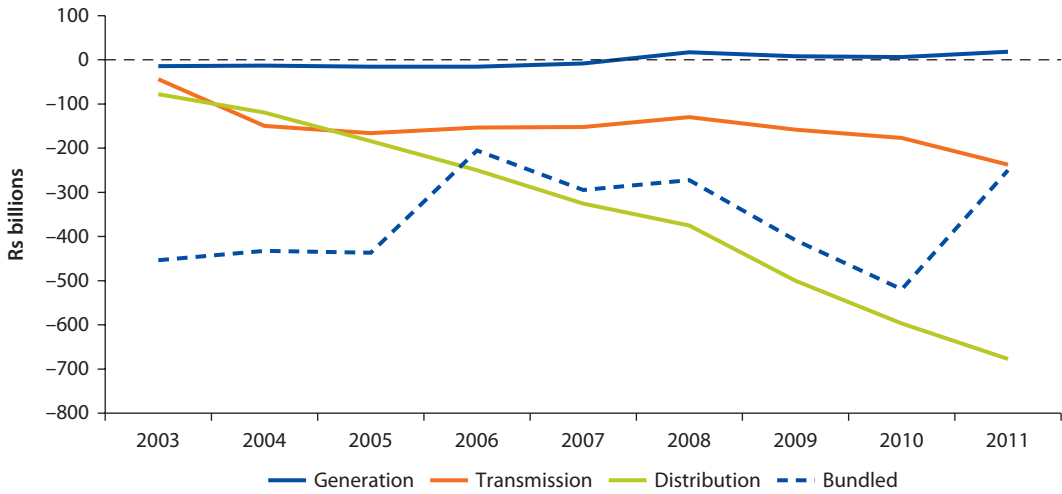
Deterioration of Distribution Finances

Power sector finances—critical to realizing sector goals—have been trending downward, especially from 2009 onward, and reached crisis proportions in 2011. The increase in sector losses has been largely plugged by substantial state subsidies and heavy borrowing by all segments of the value chain. Subsidies received by state utilities over 2003–11 totaled Rs 1.3 trillion (\$28 billion), or 2 percent of gross domestic product (GDP) in 2011. And total debt stood at Rs 3.5 trillion (\$77 billion) in 2011, equivalent to 5 percent of GDP that year. About a decade after the first bailout in 2001, the sector was again offered a financial restructuring plan in 2012. Once more, the crisis had roots in the lack of creditworthiness of state power distribution utilities, which were unable to pay their bills or repay their debts. This chapter elaborates on the evolution of sector finances since 2003 and the impact on various stakeholders.

State Subsidies to the Sector Impose a Heavy Opportunity Cost

Sectorwide accumulated losses stood at Rs 1,146 billion (\$25 billion) in 2011, more than twice (in real terms) that in 2003 (figure 3.1).¹ Accumulated losses grew at a compound annual growth rate (CAGR) of 9 percent in real terms from 2003, though the share of losses relative to GDP remained stable at about 1.3 percent. Distribution companies (discoms) and bundled utilities (state electricity boards and power departments) are by far the largest contributors to accumulated losses, though their share has fluctuated from 90 percent in 2003 to 73 percent in 2006 and back up to 81 percent in 2011. Transmission companies account for most of the rest. Generation companies, on the other hand, have collectively made profits since 2008.

Accumulated losses are concentrated in a few states: Uttar Pradesh, Madhya Pradesh, Tamil Nadu, and Jharkhand among them (figure 3.2a). Uttar Pradesh has seen steadily accumulating losses since 2003 and alone accounted for 40 percent of the total in 2011. Together, five poor-performing states account for three-quarters of the power sector's accumulated losses.

Figure 3.1 Accumulated Losses by Segment, 2003–11

Source: Khurana and Banerjee 2013.

Note: "Bundled" includes state electricity boards and power departments.

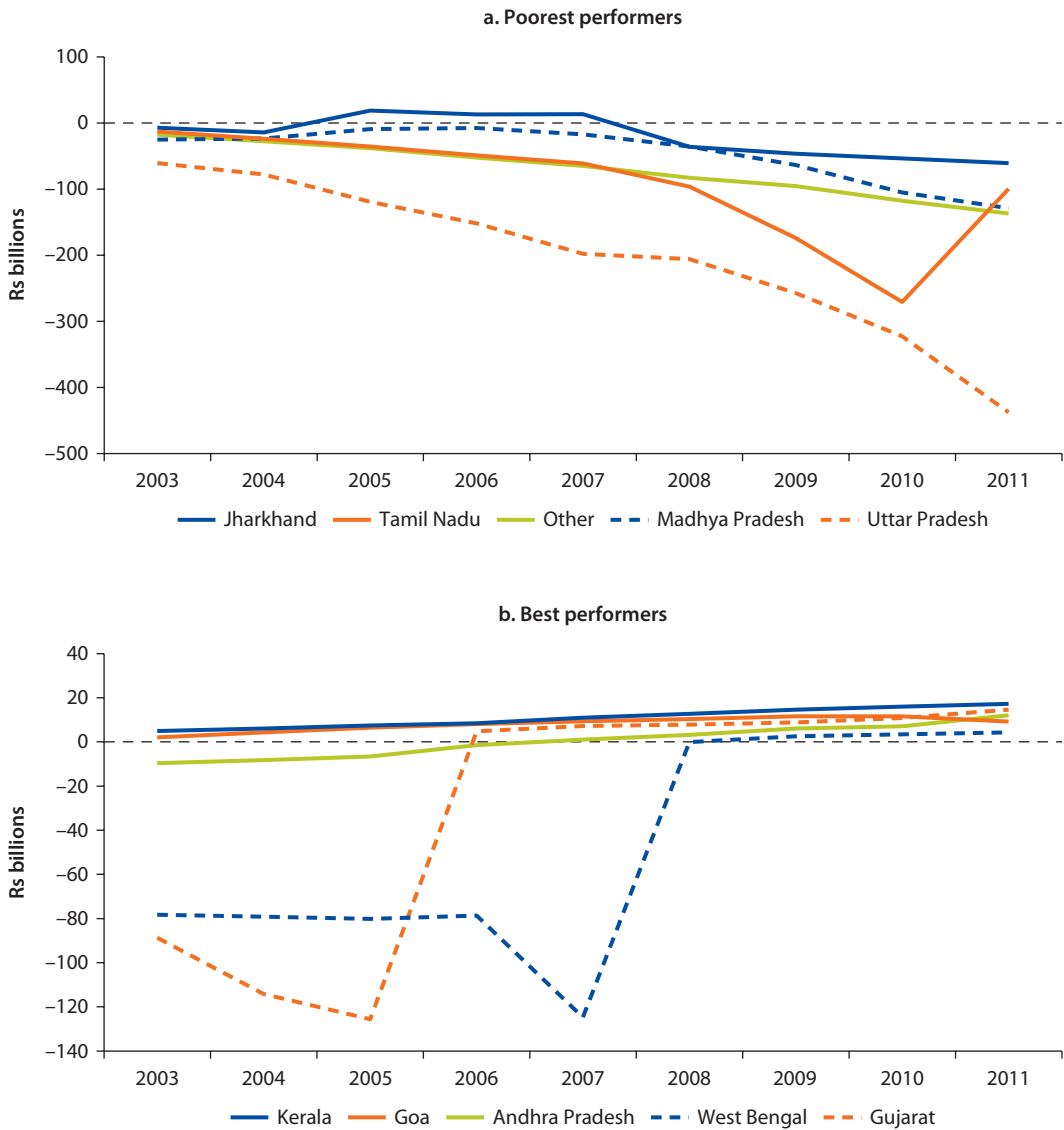
In contrast, five states had accumulated profits in 2011 (figure 3.2b): Kerala, Gujarat, Andhra Pradesh, Goa, and West Bengal, even though Gujarat and West Bengal both began the decade with slightly larger accumulated losses than any of the five poor performers.

In many states, 2011 accumulated losses amounted to a large share of state GDP—at least 1 percent and up to 25 percent. The highest level of accumulated losses was 25 percent. Of the 22 states with accumulated losses in 2011, only 5 had losses representing less than 1 percent of state GDP—Maharashtra, Punjab, Karnataka, Rajasthan, and Chhattisgarh.

While accumulated losses present a picture of the sector at a specific point in time, annual profit after tax figures show the changes in performance each year. The state government annually allocates subsidies (transfer payments) from its budget to distribution utilities, as approved by the state electricity regulatory commission (SERC). The subsidies are to cover losses from below cost-recovery pricing for agriculture and (in some states) domestic consumers. But the subsidy booked in the annual revenue requirement filings of the discoms to the SERCs may not be what is approved or received. The difference between profit after tax with subsidy booked and with subsidy received aggregated over time constitutes the accumulated loss each year.

Power sector after-tax losses for the year amounted to Rs 618 billion (\$14 billion), excluding subsidies, in 2011, or nearly 17 percent of India's gross fiscal deficit and around 0.7 percent of GDP. The losses are overwhelmingly concentrated among state electricity boards (SEBs) and power departments (from the bundled states) and discoms (from the unbundled states). In fact, the

Figure 3.2 Accumulated Losses by State, 2003–11

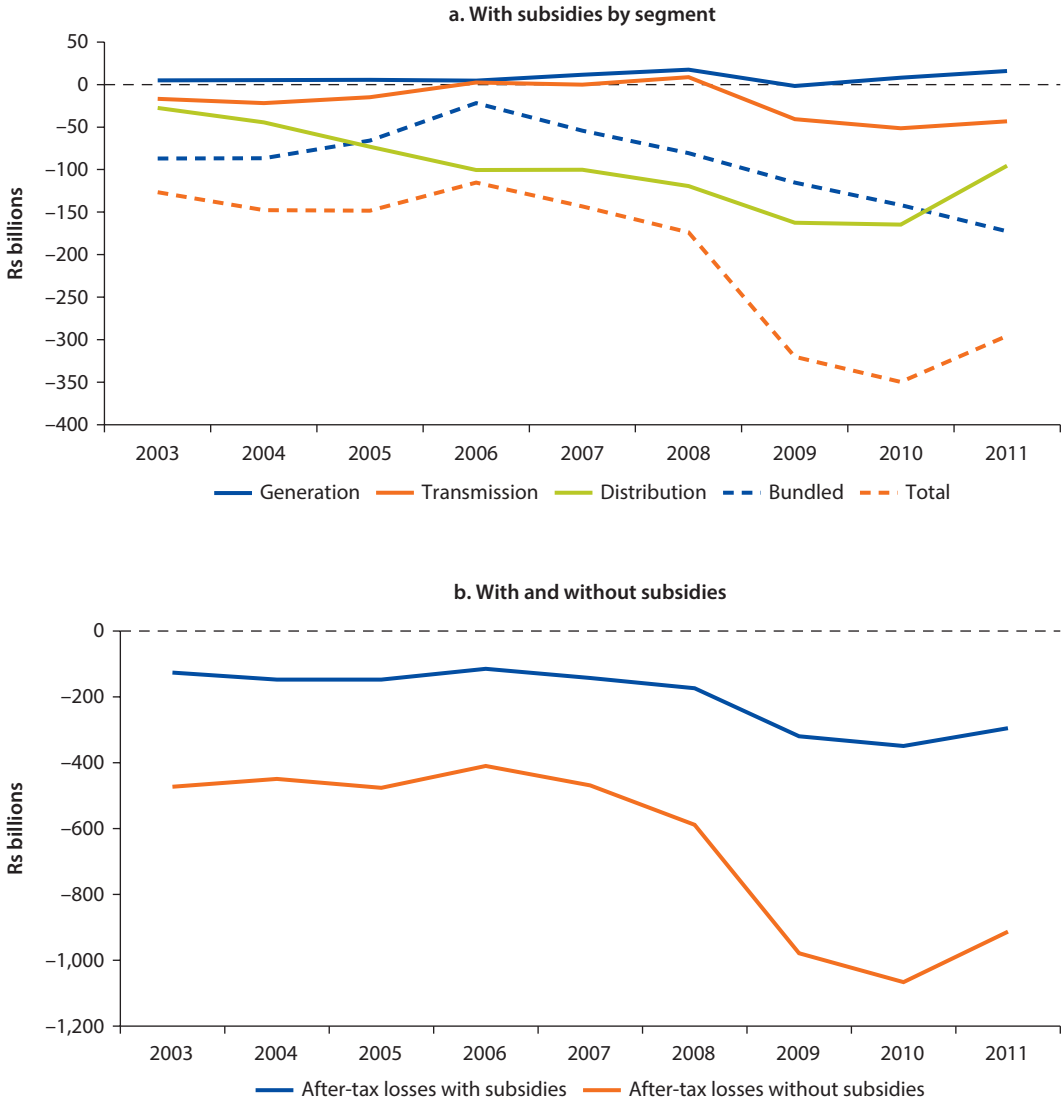


Source: Khurana and Banerjee 2013.

upstream generation segment actually recorded a small profit of Rs 15 billion (\$344 million) in 2011 (figure 3.3a).

Since 2003 total sector losses have grown 133 percent. Losses among SEBs and discoms (in unbundled states) have largely driven that trend, together growing 134 percent. There is periodic good news, however—distribution saw a modest drop in annual losses in 2011. Generation registered a growth in profits over the period, with a profit every year other than 2009, which saw

Figure 3.3 Annual Profit or Loss after Tax, 2003–11

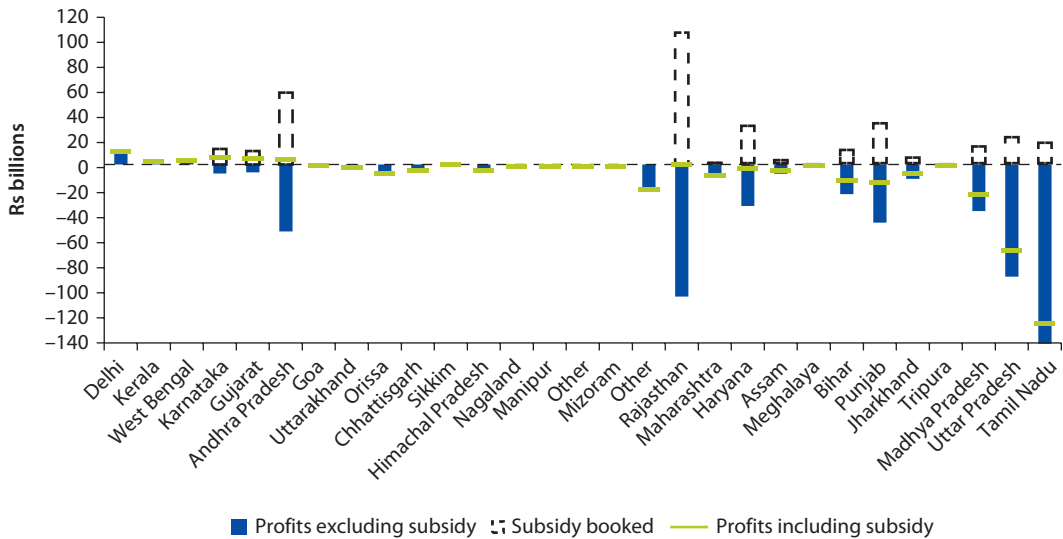


Source: Khurana and Banerjee 2013.

a miniscule loss. And transmission saw small losses shrink and become small profits by the mid-2000s, but by 2011 the gains had been reversed and the segment’s losses were larger than in 2003.

Including subsidies, annual power sector after-tax losses were Rs 295 billion (\$6.5 billion) in 2011. Thus, recorded losses fall by over 50 percent when subsidies booked are counted as revenue (figure 3.3b).

With subsidies, six states reported a profit in 2011, but only three reported a profit without subsidies: Delhi, Kerala, and West Bengal (figure 3.4). Kerala is the

Figure 3.4 Profit/Loss after Tax and Subsidies Booked, 2011

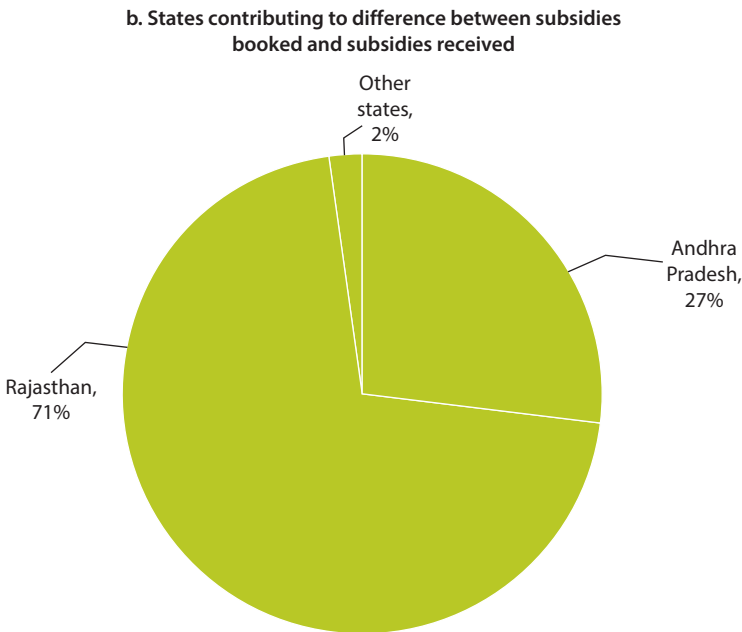
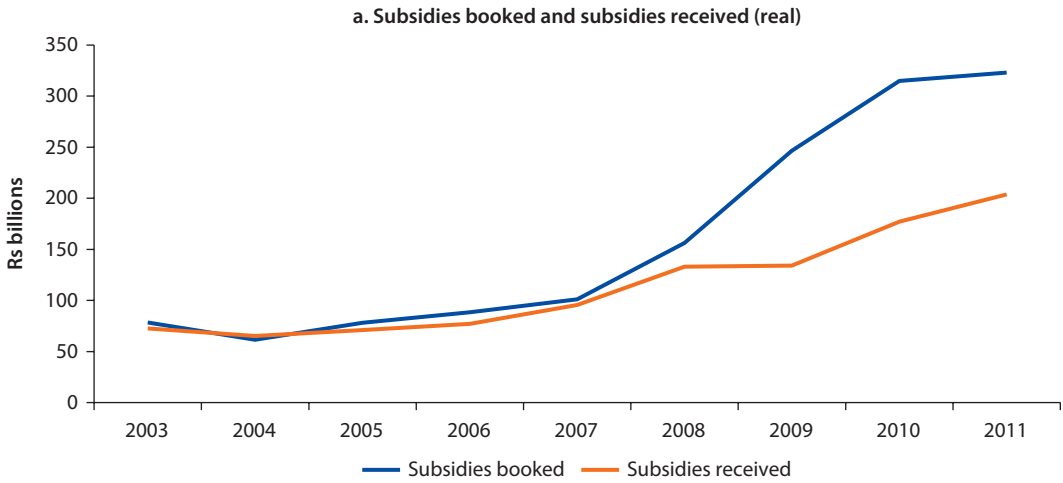
Source: Khurana and Banerjee 2013.

only bundled state reporting a profit (with or without subsidies). Most other bundled states reported a large loss in 2011. State subsidies varied widely, from zero in 14 states to Rs 130 million (\$2.8 million) in Meghalaya to more than Rs 100 billion (\$2 billion) in Rajasthan.

Not all state governments pay the entire subsidy booked by their utilities. Average annual subsidies booked have risen by 12 percent and subsidies received by 7 percent since 2003. But the divergence becomes noticeable only after 2008 (figure 3.5a). Rajasthan and Andhra Pradesh account for 98 percent of the difference between subsidy booked and received; in other states, the difference is fairly minor (figure 3.5b). Cumulative subsidies booked and received in 2003–11 are Rs 1.75 trillion (\$38 billion) and Rs 1.3 trillion (\$28 billion), respectively. Rajasthan, followed by Andhra Pradesh, Punjab, and Haryana, was the largest recipient of cumulative subsidies booked; Punjab, Haryana, Andhra Pradesh, Karnataka, and Uttar Pradesh, were the largest recipients of cumulative subsidies received.

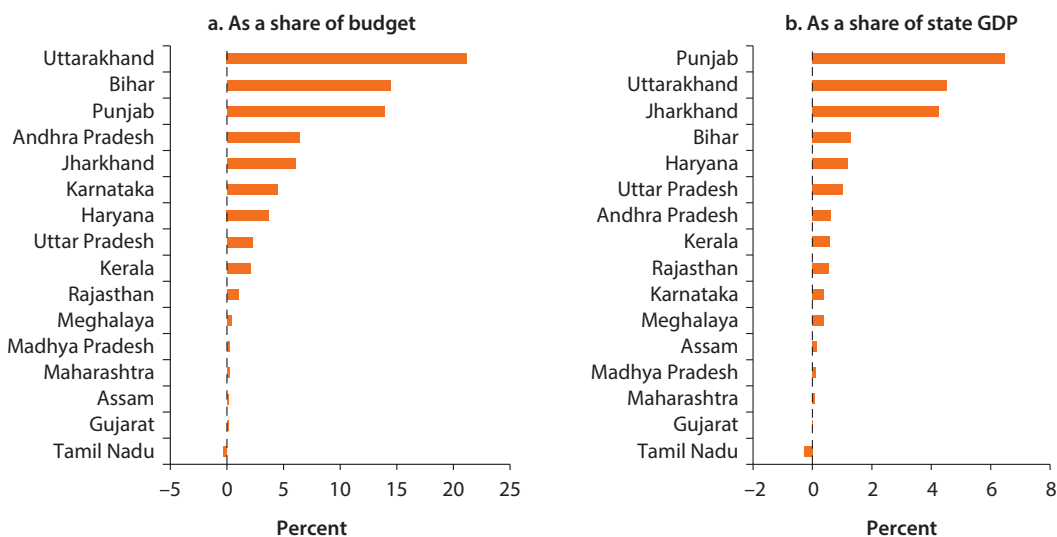
Subsidies aside, state support to the power sector includes loans, grants, and equity injections to utilities and accounts for a significant share of state budgetary spending and GDP. Subsidies are the largest component of state support. As a share of the state budget, state support to utilities averaged about 2 percent across the 16 Indian states that provided such support, but was as high as 15 percent in Bihar and 22 percent in Uttarakhand in 2011 (figure 3.6a). On average, state support to the power sector amounted to 1.3 percent of state GDP in 2011; it was more than 5 percent of state GDP in Punjab and around 4.5 percent in Uttarakhand (figure 3.6b).

Figure 3.5 Subsidies Booked and Received, 2003–11



Source: Khurana and Banerjee 2013.

Such budgetary resources granted to the power sector are an opportunity cost to the economy. Back-of-the-envelope calculations, assuming the cost of a hospital is Rs 28 million (\$0.6 million) and a school is Rs 4 million (\$0.08 million), suggest that about 15,000 hospitals and 123,000 schools could have been built in 2011 if the power sector had not preempted these funds.

Figure 3.6 State Support to the Power Sector, 2011

Source: Khurana and Banerjee 2013.

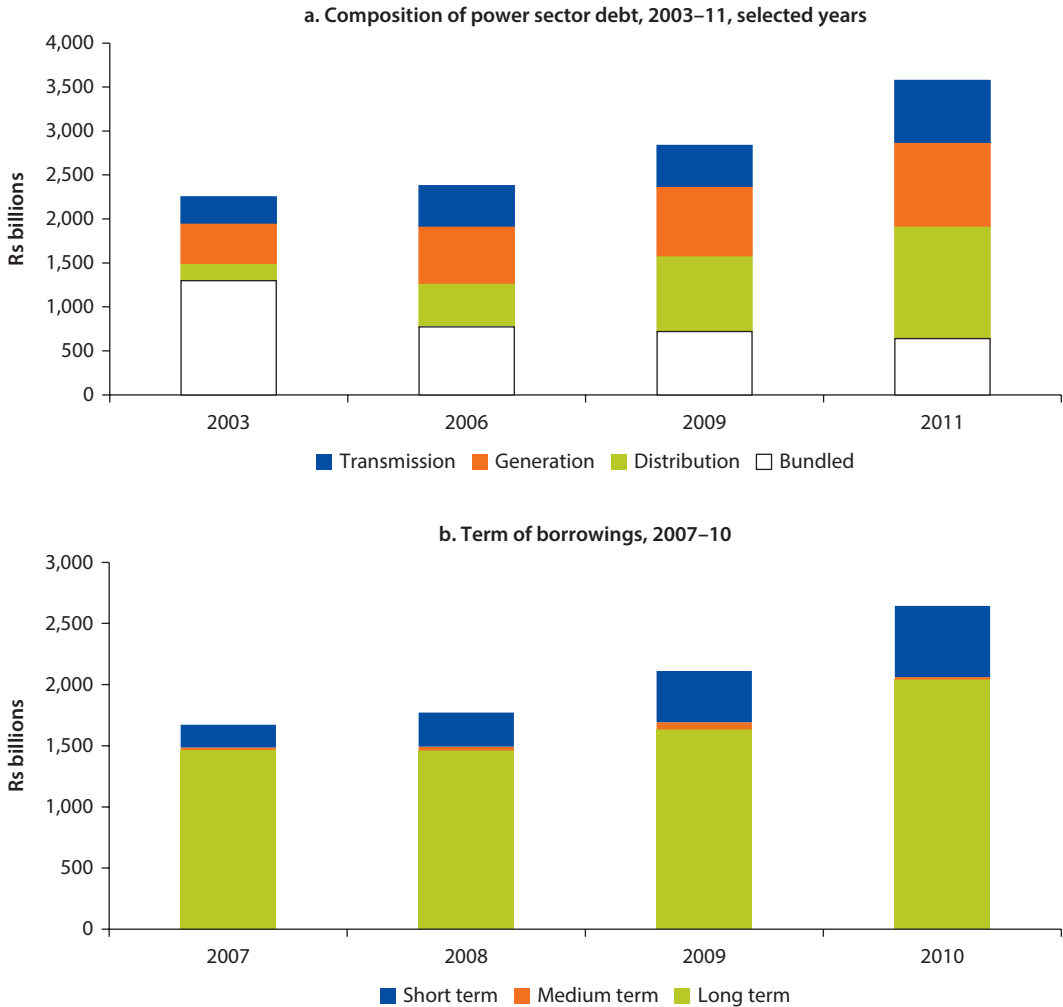
Note: GDP = gross domestic product.

Rising Power Sector Debt Has Escalated the Risk of Financial Contagion

The power sector has also been supported by substantial borrowing by all segments, with total debt growing to Rs 3.5 trillion (\$77 billion) in 2011, equivalent to 5 percent of GDP (figure 3.7a). The debt in distribution grew the fastest over 2003–11—at a CAGR of 23 percent in real terms—and expanded as a share of total debt from 9 percent in 2003 to 36 percent in 2011. Transmission and generation debt grew at real CAGRs of 10 percent and 9 percent, respectively. Bundled utilities' debt has fallen sharply in recent years, though largely because states that unbundled transferred their SEB or power department debt to the newly created utilities.

Worryingly, the tenor of the debt profile has changed. Many discoms have recently relied on short-term loans to meet operating expenses, with their share of total sector borrowing rising from 11 percent (which amounted to Rs 184 billion [\$4.5 billion]) in 2007 to 22 percent (Rs 583 billion [\$12.7 billion]) in 2010 (figure 3.7b).² By contrast, long-term loans declined from 87 percent in 2007 to 77 percent in 2010. The interest burden on utilities from short-term borrowing is heavy.

Total sector debt is concentrated among a few large states, where it represents a hefty share of state GDP (figure 3.8). In Rajasthan, Meghalaya, and Haryana, power sector debt is more than 10 percent of state GDP, and in Uttar Pradesh, a startling 43 percent. The 10 states with the largest power sector debt together accounted for 78 percent of India's total sector debt in 2011. Rajasthan had the largest absolute debt, and its borrowing grew at a massive 15 percent a year in real terms in 2003–11. Only Bihar's debt grew faster, but from a far lower base.

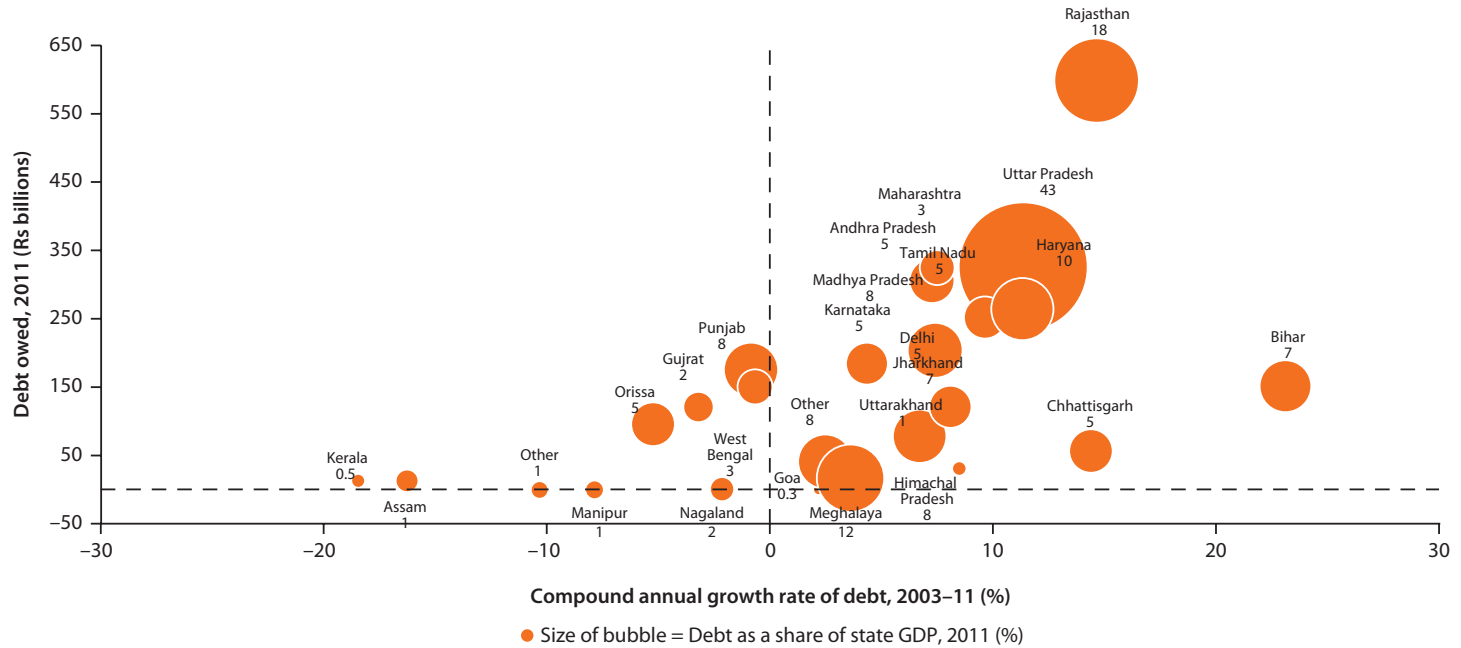
Figure 3.7 Debt Owed by the Power Sector

Source: Khurana and Banerjee 2013.

Mounting debt and continuing losses have led to a precipitous decline in overall discom creditworthiness.

In recent years, banks and financial institutions appear not to have followed strict due diligence and prudential norms. They continued making loans to discoms, implicitly relying on the quasi-guarantee of state governments in the face of known borrower insolvency. Between 2006 and 2011 lending to unbundled discoms grew 35 percent a year, accounting for 41 percent of total sector lending. In 2011 about half the sector's borrowing came from commercial banks. Other financial institutions such as the Power Finance Corporation, Rural Electrification Corporation, and Infrastructure Development Finance Company lent an additional amount at concessional rates, bringing the total contribution of commercial banks and

Figure 3.8 Debt Owed by State Utilities, 2011



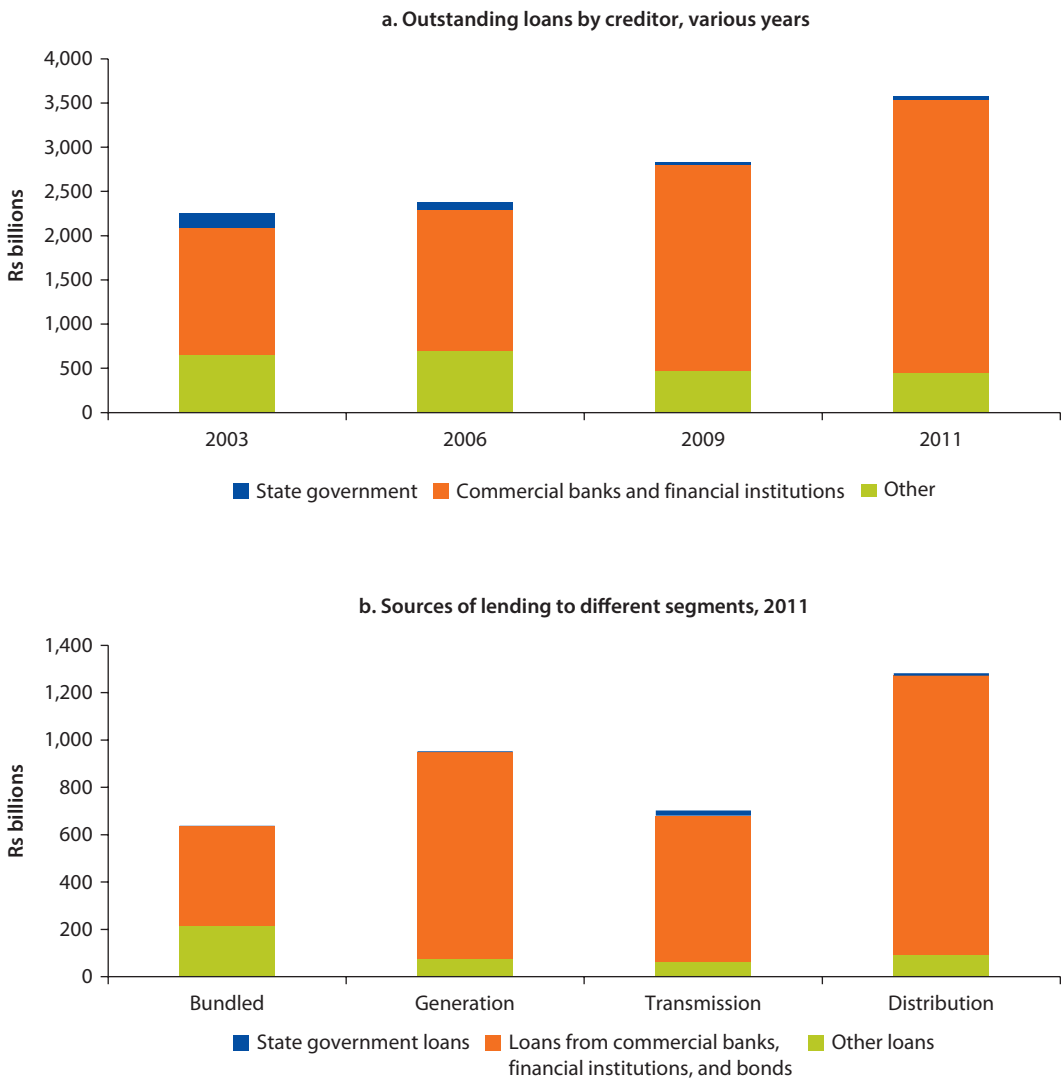
Source: Khurana and Banerjee 2013.

Note: The size of the bubble indicates debt as a percentage of state gross domestic product in 2011.

financial institutions to 86 percent (amounting to Rs 3 trillion [\$64 billion]) of power sector borrowing in 2011 (figure 3.9). The continuing flow of liquidity limited the pressure on discoms to improve performance and on state governments to permit tariff increases. Only when banks were directed to reduce lending to the sector in 2011 did states react to push through tariff increases.

Facing the prospect of huge and increasing nonperforming assets and close to their sector exposure limits, lenders finally pulled the plug on loss-making utilities in 2011/12. As credit has dried up, discoms have been unable to pay

Figure 3.9 Outstanding Loans among Subsectors and by Creditors



Source: Khurana and Banerjee 2013.

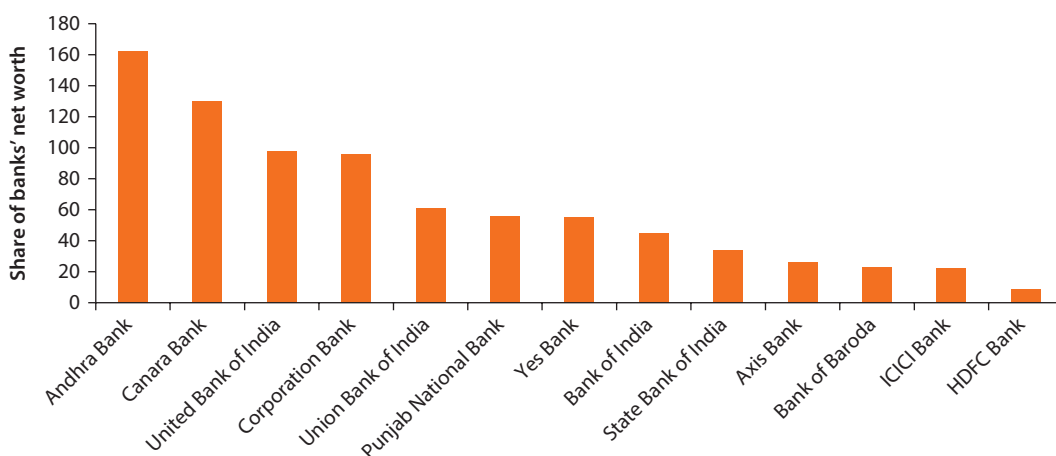
for power purchases, with a knock-on effect on upstream investor sentiment. Such profligate lending has also harmed banks' capital adequacy and net worth. More than half of 13 major state-owned banks have funded loans to the power sector of 50 percent or more of net worth; at the extreme, the funded exposure of Andhra Bank and Canara Bank is far more than their net worth (figure 3.10), raising concerns over how power sector performance could spread to the financial sector and, possibly, other parts of the economy.

The Central Government's Response to the Risk of Contagion

The poor state of utility finances has far-reaching consequences. Utilities are unable to cover their costs or make the investments required to serve customers—or both. They may also be unable to pay for power even when electricity is available in the market, and so do not purchase enough power to meet demand. This results in poor quality of supply and inadequate capacity utilization in generating stations, further weakening sector finances. Customers must resort to the use of expensive standby options, resulting in productivity losses and reduced competitiveness. Since diesel is subsidized, the costs to the exchequer for using diesel as backup power are also enormous (variously estimated to be around Rs 100 billion [\$2 billion]–150 billion [\$3.2 billion] a year).³ Finally, the financial sector, which has in effect bankrolled the deficits, now faces huge risks because of the loans made to the power sector for capital investments and for working capital.

At the end of 2011, within a decade of the 2001 central government bailout of SEBs, the downward slide in utility finances produced a crisis of power sector creditworthiness, with utilities in several states needing to be rescued again. The bailout this time could end up being four times larger than that in 2001.

Figure 3.10 Funded Loans to the Power Sector as Share of Net Worth of 13 Major Banks, 2010
Percent



Source: Khurana and Banerjee 2013.

In October 2012 the government announced a Scheme for Financial Restructuring of State Distribution Companies, available to all loss-making discoms, that may total Rs 1.9 trillion (\$18.7 billion; Ministry of Power 2012). Under the initiative, state governments would take over 50 percent of the short-term liabilities of distribution utilities outstanding as of March 31, 2012, and convert it into bonds to be issued by discoms to participating lenders, with the backing of state governments. The banks would restructure the other 50 percent, with a three-year moratorium on repayment. The restructured debt, too, would be guaranteed by state governments.

State governments are part of a tripartite agreement to implement the restructuring, in which discoms promise to regularly file petitions for tariff revisions with their respective SERCs, in line with costs, and reduce aggregate technical and commercial losses. The central government is making available conditional transitional financing to support the effort. Two committees, one each at the state and the central levels, are monitoring the plan's progress. Discom performance is to be verified annually through a third party appointed by the Central Electricity Authority.

But bailouts limit the incentives of utilities, lenders, and others to work to achieve financial sustainability because they insulate sector participants from the consequences of their choices. Banks with high exposure to poorly performing utilities are among the biggest beneficiaries of the bailout, since a large share of their loans would arguably have turned bad otherwise. While utilities have to meet certain conditions to benefit from the October 2012 plan, the conditions appear unlikely to remove moral hazard.

Projected Sector Finances at the End of the 12th Five-Year Plan

Projections for 2012–17, prepared individually for the distribution, transmission, and generation segments in each state and for bundled utilities, indicate that sector finances will continue trending downward in the near future. Sector profits after tax (excluding subsidies) are projected to amount to a loss of Rs 2,013 billion (\$43 billion) in 2017 if there are no tariff increases (up from a loss of Rs 618 billion [\$14 billion] in 2011). While the generation and transmission companies are projected to earn profits in 2017, discoms and bundled utilities will continue incurring heavy losses. Even if tariffs rise 6 percent a year to keep up with the cost of supply, sector annual losses in 2017 are projected to be Rs 1,253 billion (\$27 billion), which will largely need to be met by the government because the recent crisis has increased sector risk and made banks and financial institutions wary of lending to the sector.

The gap between average cost and average revenue is the main driver of high financial losses. States can address the gap by investing in efficiency improvements and tariff increases. Even then, there will be a rising need for state support. Over 2013–17, 14 states are forecast to reduce the gap, but only 5 will fully cover the cost of supply in 2017 (Goa, Himachal Pradesh, Kerala, Maharashtra, and West Bengal). Himachal Pradesh is likely to go from a moderate loss to profit,

while Meghalaya and Haryana are forecast to suffer the widest increase in the gap (figure 3.11).

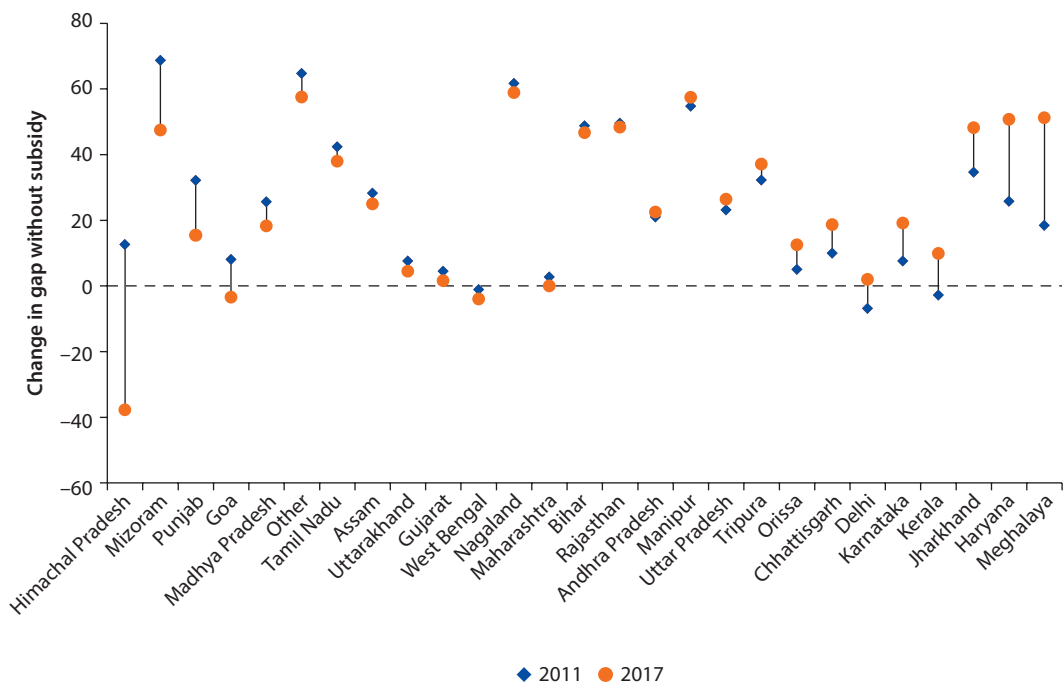
In 2017 the gap without subsidy is projected to be less than 15 percent of average cost in only nine states and 15–30 percent in seven states. Of the latter group, Andhra Pradesh and Karnataka both perform considerably better when subsidies are included. For three states (Punjab, Maharashtra, and Gujarat), the gap disappears once subsidies are included. For four states that receive subsidies (Bihar, Haryana, Rajasthan, and Tamil Nadu), the gap is reduced somewhat but still remains high (figure 3.12).

Eight states (Bihar, Haryana, Himachal Pradesh, Karnataka, Kerala, Rajasthan, Tamil Nadu, and Uttar Pradesh), accounting for 70 percent of the sector’s short-term liabilities, have expressed interest in participating in the debt recast for utilities under the 2012 financial restructuring scheme. The projections for 2017 indicate that several of these states are at risk of not becoming profitable because of their poor operating performance (table 3.1).

States that sign up for support under the 2012 financial restructuring scheme will have stringent targets, including a requirement to close the gap between average cost and average revenue during the debt repayment moratorium period

Figure 3.11 Projected Change in Gap without Subsidy, 2011–17

Percent

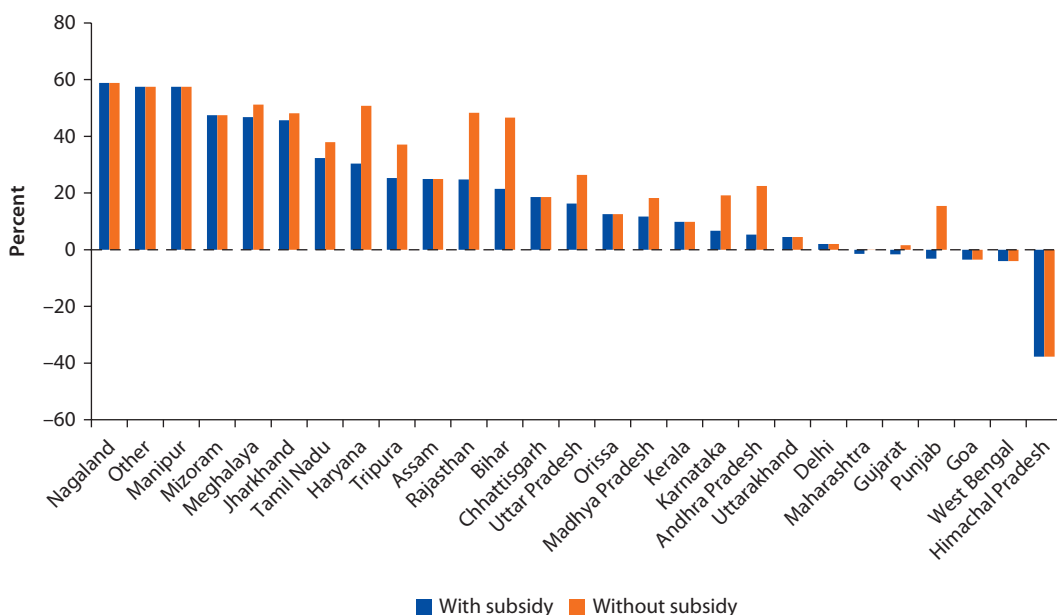


Source: Khurana and Banerjee 2013.

Note: Gap as a share of average cost: $[\text{average cost} - \text{average revenue}] / [\text{average cost}]$. Projections are not available for the remaining states.

(three to five years). So, actual tariff increases and efficiency-enhancing efforts are expected to be more aggressive than those underlying the scenarios described earlier, where even with an annual tariff increase of 6 percent, many states will continue to make losses. The states participating in the financial restructuring scheme will need to establish clear tariff paths over the next five years that are firmly oriented to cost recovery.

Figure 3.12 Gap with and without Subsidy, 2013–17



Source: Khurana and Banerjee 2013.

Note: Projections are not available for the remaining states.

Table 3.1 Status and Projections of Candidate States for Financial Restructuring

State	Profit after tax, 2011 (with subsidy)		Total loans, 2011		Ratio of debt to revenue, 2011	Projected gap with subsidy, 2017	
	Rs million	USD million	Rs million	USD million	(percent)	Rs/kWh	USD/kWh
Bihar	-13,320	-285.41	151,480	3,245.77	419	1.42	0.030
Haryana	-3,290	-70.49	263,710	5,650.52	134	1.83	0.040
Himachal Pradesh	-5,110	-109.49	41,780	895.22	118	-2.17	-0.046
Karnataka	5,350	114.63	184,400	3,951.15	80	0.27	0.006
Kerala	2,410	51.64	13,840	296.55	20	0.55	0.012
Rajasthan	-40	-0.86	596,280	12,776.52	201	1.78	0.040
Tamil Nadu	-129,510	-2775.02	251,440	5,387.61	120	1.91	0.041
Uttar Pradesh	-70,180	-1503.75	325,010	6,964.00	81	0.73	0.016

Source: Khurana and Banerjee 2013.

Note: kwh = kilowatt-hour.

Notes

1. This figure includes state subsidies as revenue.
2. The balance sheets of distribution companies have grown, fueled mainly by debt, but these financial liabilities have not created assets.
3. The diesel subsidy in current crude prices is around Rs 12 (\$0.25) per liter. Converted to per kilowatt-hour (kWh) costs of electricity, this means an imputed subsidy of Rs 1.5 (\$0.03) per kWh of electricity generated through diesel. At hours of operation varying between two and three a day, the diesel subsidies provided by the central government to back up power users would be between Rs 88 billion (\$1.9 billion) and Rs 131 billion (\$2.8 billion). These subsidies are effectively being paid out by the central government in cash to diesel backup users.

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Drivers of Losses

Worsening sector losses result from a growing wedge between average cost (total cost per unit input energy) and average revenue (total revenue per unit input energy).¹ Average cost has gone up, largely due to rising power purchase costs—themselves spurred by fuel shortages, which have resulted in higher fuel prices—and due to rising interest costs from the sharp expansion in utilities' debt. At the same time static tariffs have dampened revenue growth, though persistent collection and distribution losses are responsible for the bulk of the cost–revenue gap. This chapter looks more closely at the reasons for these continuing losses.

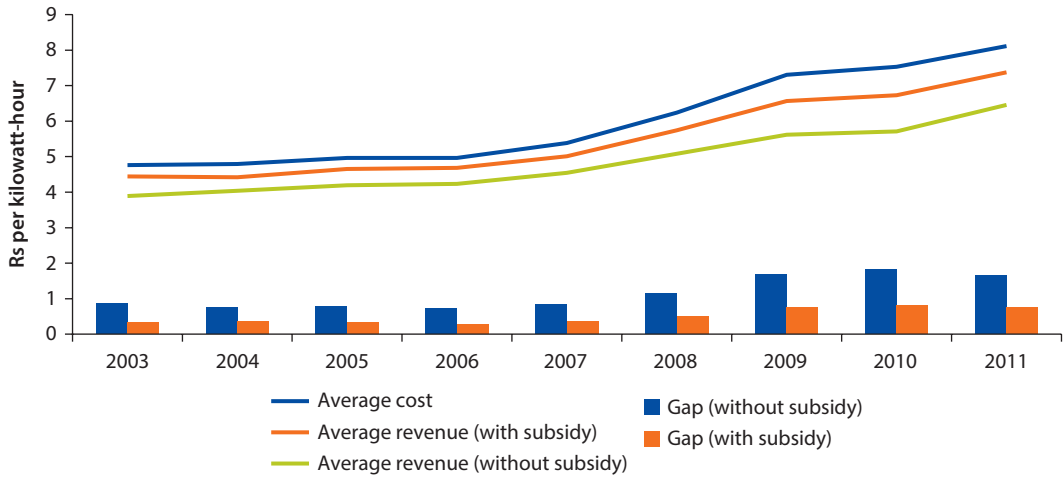
Rising Gap between Cost and Revenue

The cost–revenue gap has almost doubled since 2003. Even with subsidies, a notable gap persists. Average cost rose at about 7 percent a year over 2003–11, increasing by 70 percent in real terms over the period. Across India the average cost per kilowatt-hour (kWh) of input energy in 2011 was Rs 4.06 (\$0.08). Bihar, Delhi, Rajasthan, and many of the North-Eastern states had fairly high cost profiles. On the other side of the cost–revenue wedge, average revenue grew at only 6 percent a year over 2003–11, or 66 percent in real terms over the period (figure 4.1).

In 2011 Delhi, Kerala, and West Bengal were the only states where average revenue excluding subsidies covered average cost (figure 4.2). Including subsidies booked adds Andhra Pradesh, Gujarat, and Rajasthan to the group of states in which average revenues cover average cost; in these states, subsidies booked are almost exactly equal to losses. Mizoram reports the largest gap—revenue recovered only 69 percent of costs. None of the four highest-gap states receives subsidies. Rajasthan and Bihar also report large gaps but subsidies cover all (Rajasthan) or a large part (Bihar) of the cost–revenue gap in these states.

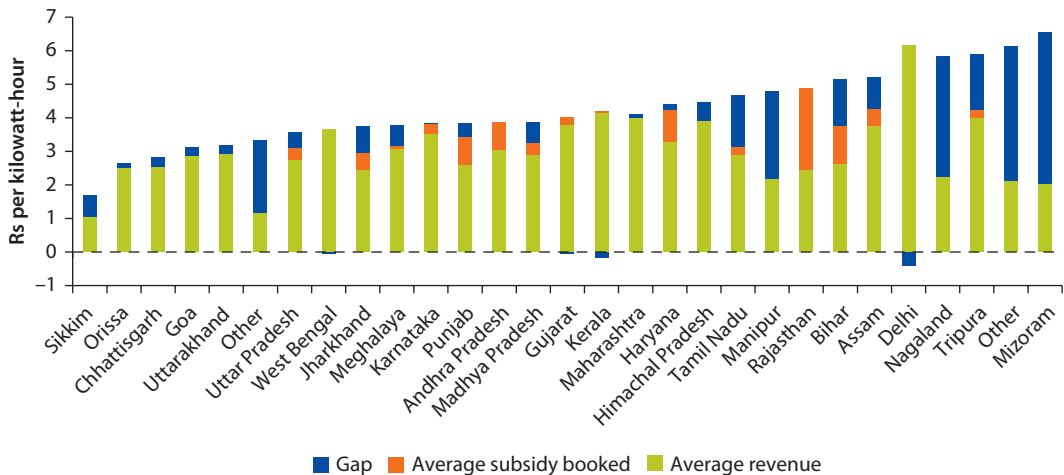
The rise in average cost has been driven largely by an increase in power purchase cost, which has seen its share in total cost climb from 56 percent in 2003 to 74 percent in 2011 (figure 4.3a). Its share of total cost is over 75 percent in

Figure 4.1 Average Cost and Average Revenue, 2003–11



Source: Khurana and Banerjee 2013.

Figure 4.2 Gap between Average Cost and Average Revenue, 2011

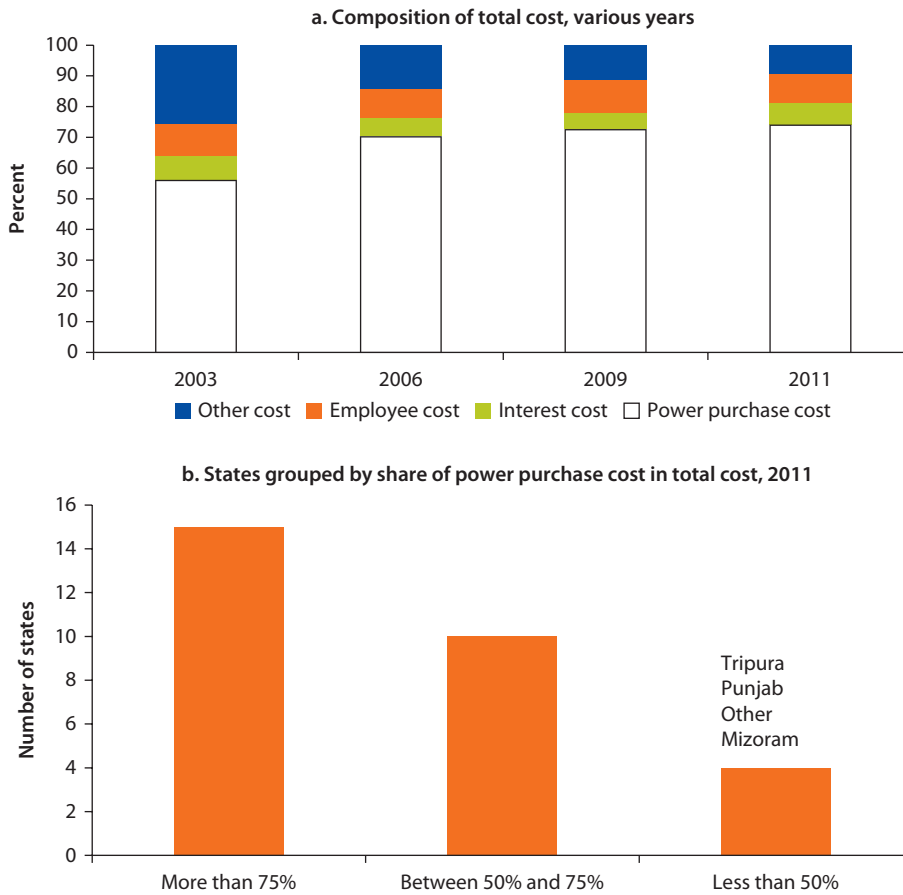


Source: Khurana and Banerjee 2013.

15 states, though it varies from over 85 percent in Karnataka and Gujarat and over 80 percent in six other states to less than 50 percent in four states (figure 4.3b). Employee and interest costs also contribute significantly to total cost: employee costs rose in 2009 because of the large pay increases mandated by the Sixth Pay Commission, though they have moderated slightly since, and interest costs rose due to the large increase in utility debt over this period.

Rising power purchase costs have been driven by two factors. First, an increase in fuel costs: an extreme shortfall in coal has led to a spike in reliance on

Figure 4.3 Composition of Total Cost



Source: Khurana and Banerjee 2013.

imported coal, which is often two to three times as expensive as domestic coal. During the 11th plan period (2007–12), coal-based power capacity increased by 9.5 percent a year, from 68 gigawatts (GW) to 112 GW. Over the same period, domestic coal production increased by only 5 percent a year, widening the gap between demand and supply and leading to increased imports. In addition to a sharp increase in the use of imported coal from 10 million tons in 2008 to 45 million tons in 2012, power producers have resorted to greater use of e-auctions to purchase coal. Uncertainty over long-term fuel availability, in combination with rising fuel prices that make existing power purchase agreements unremunerative, have already constrained new investment in power generation; 37 GW of generation capacity was stalled in 2012 (see appendix H).

Second, utilities have failed to adequately plan for power procurement. In theory, utilities should project demand and load duration curves and plan long-, medium-, and short-term power purchases based on these projections. But in practice, they often fail to plan and so regularly end up having to purchase

expensive electricity in the short-term markets or through unscheduled interchange (or, alternatively, resort to load shedding). Andhra Pradesh is known to rely on load shedding, while Haryana, Punjab, Uttarakhand, and Uttar Pradesh resort to heavy use of the unscheduled interchange mechanism.

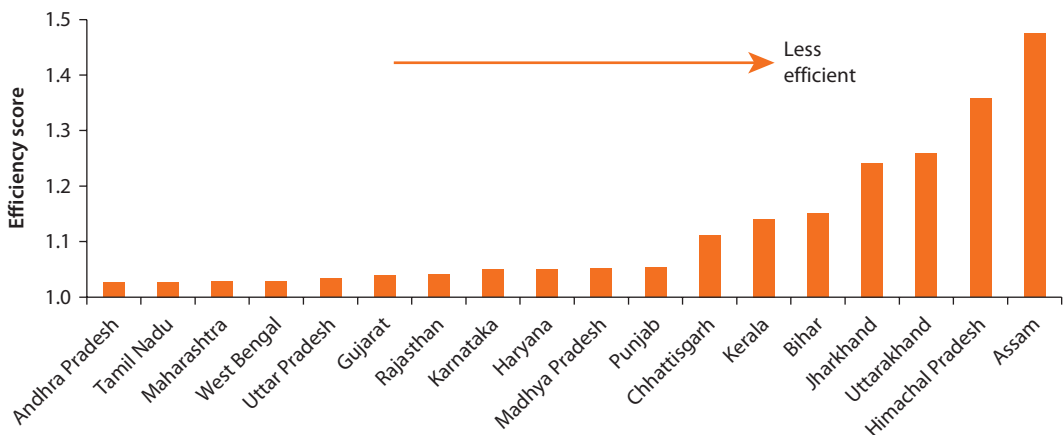
Rising interest costs, driven by distribution companies' (discoms') increased borrowing, have also put upward pressure on utility cost profiles. In recent years, with the limited revisions of retail tariffs, discoms have had to borrow to meet operating expenses. If there is no relief on the revenue side (through tariff changes and efficiency improvements), this initiates a vicious circle, in which interest costs grow and utilities end up taking fresh short-term loans to repay earlier loans.

Inefficiencies in Distribution and Generation

Power purchase costs differ widely across states, driven by a variety of fundamentals² and, as noted, by the effectiveness of a state's power procurement planning (or lack thereof). Stochastic frontier analysis³ can be used to control for the variations in those fundamentals and estimate how far each state is from its cost-efficiency frontier (figure 4.4).

By efficiency score, Assam, Himachal Pradesh, Uttarakhand, Jharkhand, and Bihar are the least-efficient states in power purchase. Bihar and Jharkhand are inefficient largely because their state-owned generation plants have very low plant load factors; thus, they rely heavily on out-of-state power purchases despite having in-state generation capacity. By contrast, Assam, with an 8 percent energy deficit, has not secured adequate supply through long-term contracts. To meet its demand shortage, it buys large amounts of power (24 percent in 2010) through expensive bilateral transactions and on power exchanges. Himachal Pradesh and

Figure 4.4 Power Purchase Efficiency Scores Based on Stochastic Frontier Analysis



Source: Khurana and Banerjee 2013.

Note: Unity represents efficiency, and higher scores indicate greater inefficiency.

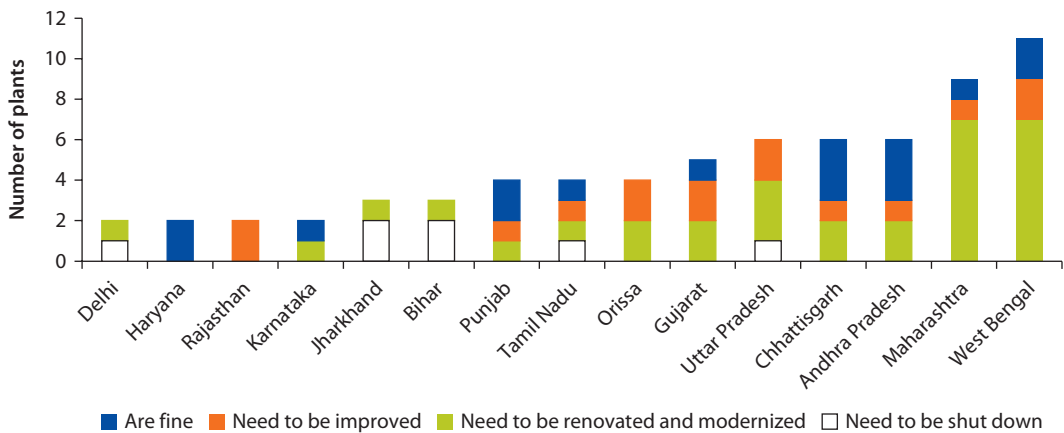
Uttarakhand rely heavily on in-state hydro resources that, while inexpensive, are not reliable in the winter—or in the summer if the monsoon is delayed. In such cases these states have had to sign short-term power contracts to make up the deficit, driving up their power purchase costs.

Inefficiencies in distribution also reflect inefficiencies in the upstream generation segment. Substantial cost savings are possible by using fuel resources efficiently. Background analysis for this report has used data envelopment analysis to identify chronic underperformers in generation (Khurana and Banerjee 2013).⁴ In these cases, shutting down the plants and using the fuel in efficient plants would serve both utility finances and the sector much better. It would also allow the use of efficient generation capacity currently stranded due to a shortage of fuel.

In a group of 80 thermal plants selected for this analysis (out of the 107 in the 2010 Central Electricity Authority review; CEA 2011), representing 91 percent of total thermal capacity in India, the data envelopment analysis score ranges from 0 to 1, with 1 being the most efficient (within the sample). Based on the analysis, of 69 state-owned thermal plants, more than half need either to be shut down or to be renovated and modernized. All the plants in Bihar and Jharkhand fall into these two categories (figure 4.5).

If the six worst-performing power plants had been operating at the national average station heat rate,⁵ more than 2,750 million kWh of additional electricity could have been generated, saving the generation companies about Rs 9 billion (\$0.2 billion). This would also have enabled the states to reduce their reliance on short-term purchases, further saving about Rs 9 billion (\$0.2 billion) for the discoms. Uttar Pradesh and Bihar would particularly have benefited; the two states accounted for more than 30 percent of total short-term purchases in 2011.

Figure 4.5 Thermal Power Plant Status by State



Source: Khurana and Banerjee 2013.

The savings would have been even greater, at Rs 15 billion (\$0.32 billion), if the six worst-performing plants had operated at heat rates similar to those of the best plants.⁶ If the coal used in the inefficient plants were used efficiently, thus reducing the need for imported coal, the overall annual savings for the utilities could be roughly Rs 20 billion (\$0.43 billion). Even allowing for fixed costs for the efficient plants, the utilities would still save Rs 15 billion (\$0.32 billion).⁷

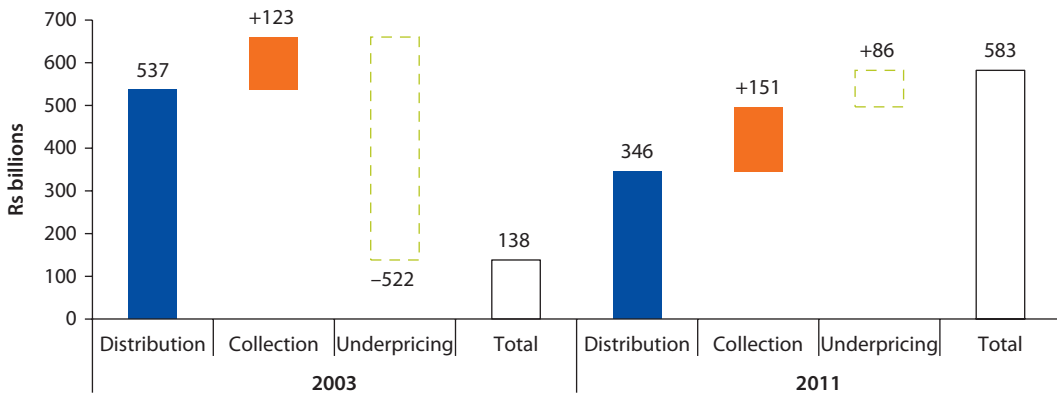
Decomposition of Utility Losses

To understand the factors that have contributed to the power sector’s financial condition, utility losses⁸ can be decomposed into three buckets: losses due to distribution energy losses above the international norm of 10 percent, losses due to undercollection of bills, and losses due to below-cost-recovery pricing (Ebinger 2006).

While cost recovery basically requires the tariff to equal or exceed average cost, a more stringent requirement is used here. Cost recovery is the tariff level that covers (equals) average cost plus a premium to account for “normal” distribution losses, which are set at 10 percent for India in this analysis. So an efficiently operating utility (with normal distribution losses and 100 percent collection) that has a tariff equal to cost recovery, as defined above, would break even.⁹

Slower growth in revenue than costs over 2003–11 was driven mainly by tariff increases that did not keep up with cost increases (figure 4.6). In 2003 states were in aggregate charging an average billed tariff¹⁰ well above cost recovery, and losses that year were overwhelmingly driven by distribution losses. In contrast, in 2011 states were in aggregate charging an average billed tariff below cost recovery, though 15 states had an average billed tariff above cost recovery. Thus, underpricing emerged as an important contributor to losses, though distribution inefficiencies, while smaller than in 2003, still made by far the largest contribution to total losses.

Figure 4.6 Decomposition of Losses, 2003 and 2011



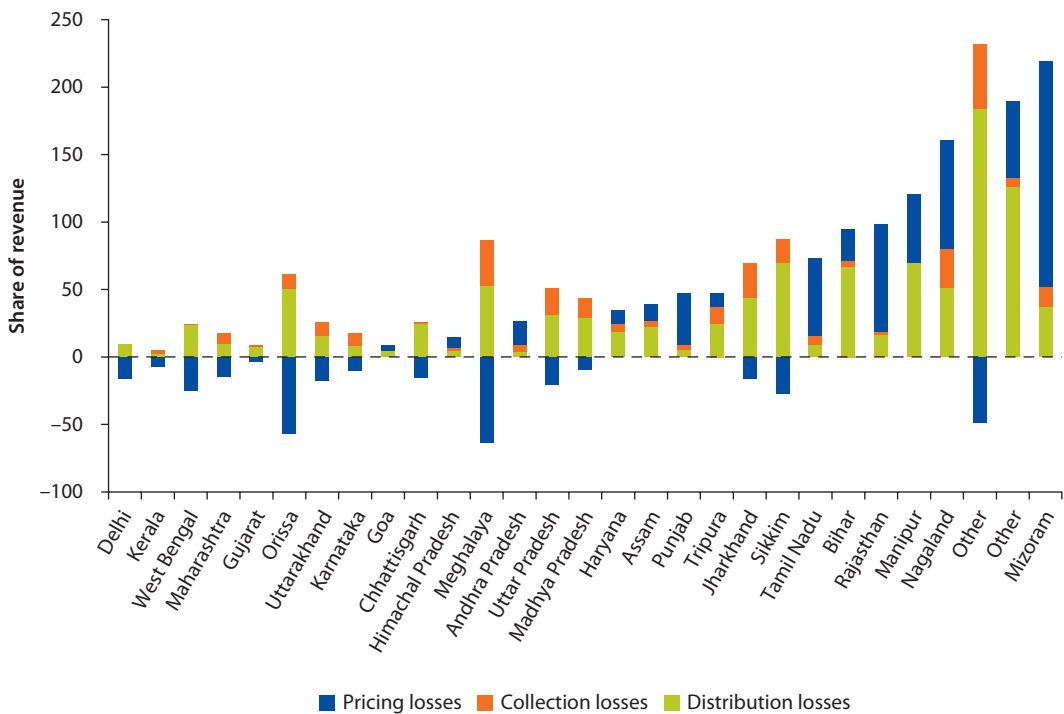
Source: Khurana and Banerjee 2013.

Among states, while losses are highest in absolute amount in Tamil Nadu, Rajasthan, and Andhra Pradesh, losses are highest as a share of revenue in five small states, where losses are higher than 100 percent of revenues (figure 4.7). The contribution of each of the components differs across states. Typically, distribution losses contribute the most to total losses: in Madhya Pradesh, Haryana, Bihar, Jharkhand, Assam, Manipur, and Tripura, among others, more than half the losses are from distribution losses. But for Tamil Nadu, Rajasthan, Andhra Pradesh, Punjab, Himachal Pradesh, Mizoram, and Nagaland, underpricing has also been a relevant factor, contributing more than half the losses. For Uttar Pradesh, Karnataka, Maharashtra, Uttarakhand, and Meghalaya, collection losses matter, too. This kind of decomposition can identify the areas where intervention is warranted and by whom: from the discoms (if the losses are primarily from distribution and collection inefficiencies) or from the regulator (if primarily from underpricing).

Underpricing

In most states average billed tariffs have kept pace with increases in the cost-recovery level, as defined above to take into account “normal” distribution

Figure 4.7 Decomposition of Losses, as Share of Revenue
Percent



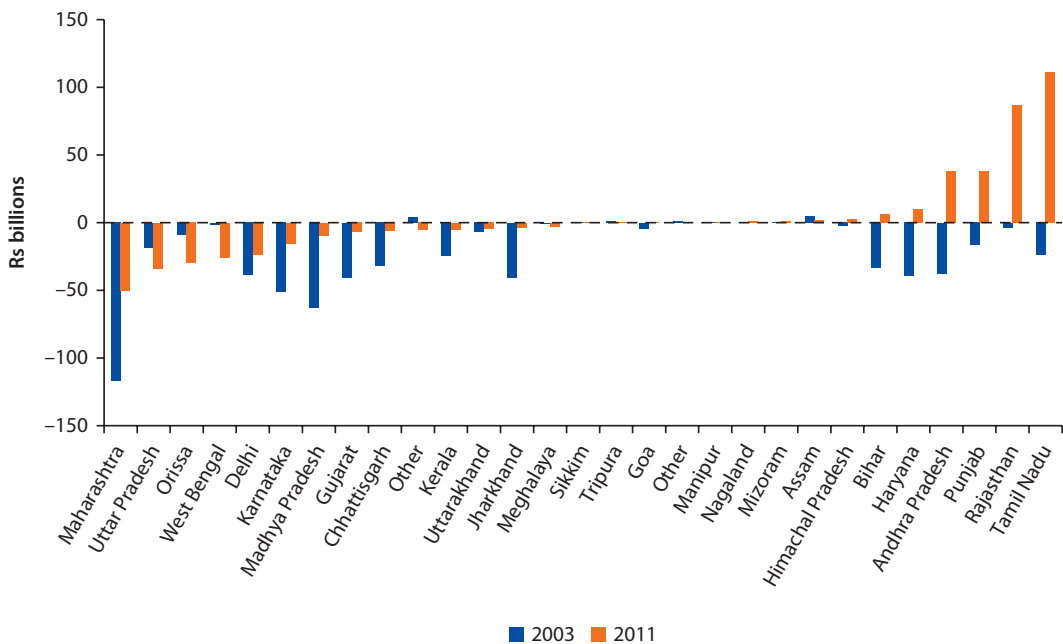
Source: Khurana and Banerjee 2013.

losses of 10 percent, but the number of states where underpricing has contributed to utility losses has risen over time. In 2003 tariffs did not meet cost-recovery levels in only 7 states—in 2011 the number of such states was 14. Some states show a precipitous fall in cost recovery, such as Bihar, Haryana, Punjab, Rajasthan, Maharashtra, and Tamil Nadu. But more important, even for states where tariffs continued to meet cost-recovery levels and so did not add to utility losses, the margins were smaller. In addition, there are a few states that reduced underpricing. Uttar Pradesh, Orissa, West Bengal, and Meghalaya all saw gains from increases in tariffs, and thus underpricing made a smaller contribution to utility losses in 2011 than in 2003 in these states (figure 4.8).

For India in 2011, the average billed tariff trailed the cost-recovery tariff level by Rs 0.16/kWh (\$0.003/kWh), while average cost was lower than average billed tariff by Rs 0.32/kWh (\$0.007/kWh). Since 2003 the average billed tariff has been higher than average cost, but it dropped below the cost-recovery level from 2008 onward (figure 4.9a). In 2011, 15 states had average billed tariffs exceeding the cost-recovery tariff level, while 20 states had average billed tariffs higher than average cost. Assam, Goa, Haryana, Himachal Pradesh, and Tripura all had average billed tariffs that met average cost but did not reach cost recovery.

On average, states increased tariffs at least once every two years from 2007/08 to 2012/13. Three states increased tariffs each year while Sikkim did

Figure 4.8 Losses from Underpricing



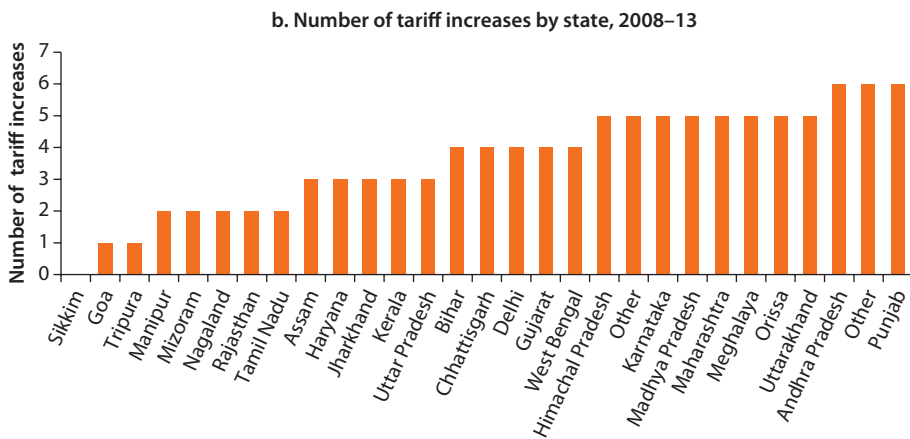
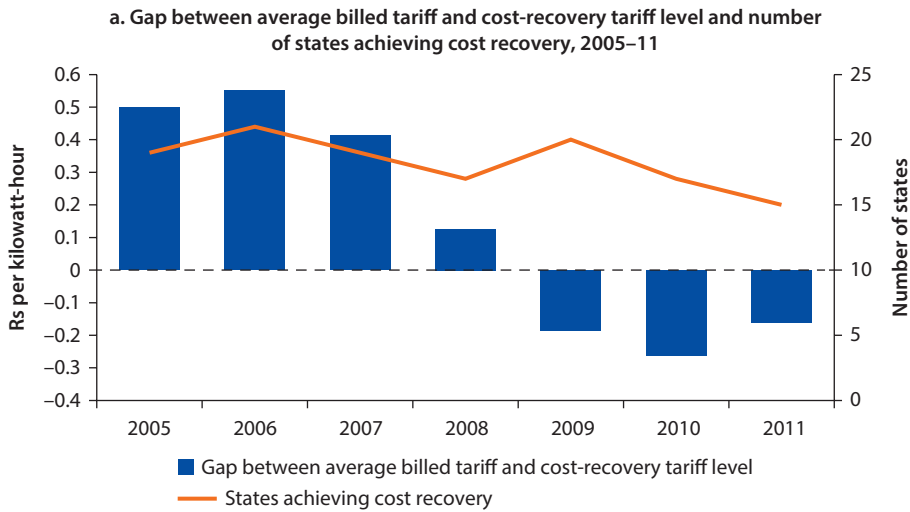
Source: Khurana and Banerjee 2013.

not revise tariffs at all in the six-year period. The frequency of tariff increases varied from year to year—for instance, in 2008/09 only 13 states reported tariff increases, compared with 2012/13 when about 26 states issued orders to raise tariffs. Goa—one of the best performers—did not issue a tariff order for the first five years in this period, finally raising tariffs only in 2012/13 (figure 4.9b).

Distribution

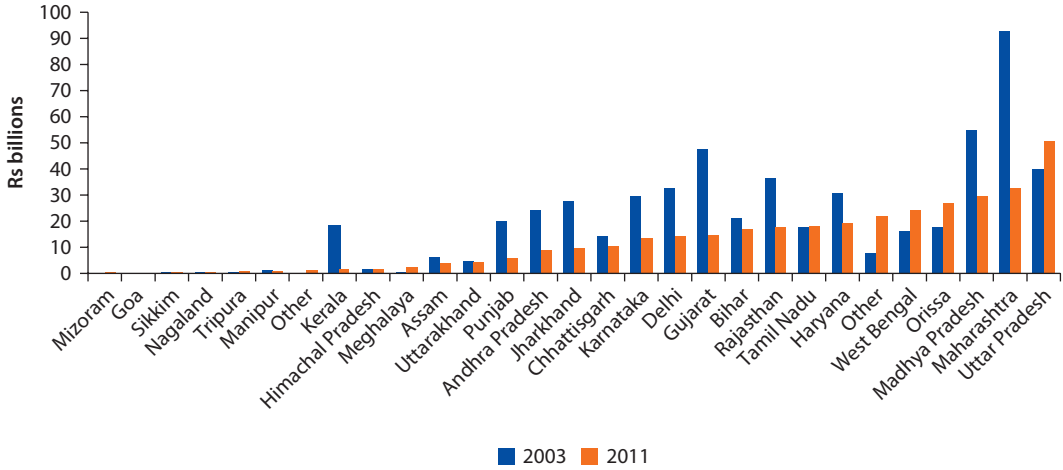
The difference between input energy and energy sold equals the distribution loss. Distribution losses, comprising both technical and nontechnical losses, have followed a downward trajectory since 2003 when average distribution losses were about 32 percent and 18 states reported losses above this average (figure 4.10).

Figure 4.9 Tariff Performance



Source: Khurana and Banerjee 2013.

Figure 4.10 Losses from Distribution



Source: Khurana and Banerjee 2013.

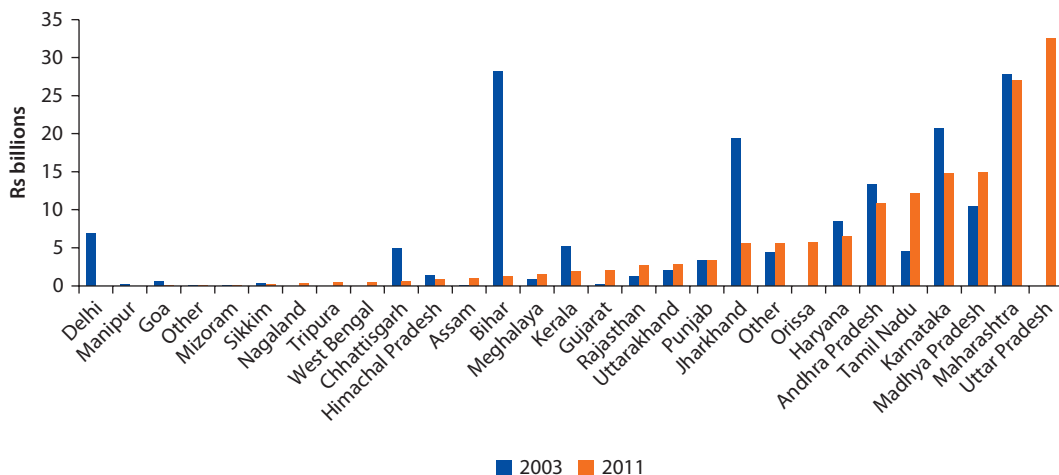
Three states have consistently reported the highest distribution loss percentage. In 2003 Manipur’s distribution losses were 66 percent, which meant it sold only 34 percent of the energy it input to the grid. In 2011 distribution losses averaged 21 percent across all states, with the lowest distribution losses reported in Kerala, at about 12 percent, similar to international best practice. Andhra Pradesh, Goa, and Punjab also recorded distribution losses of less than 15 percent. While distribution’s contribution to total utility losses has fallen in more than two-thirds of states, performance has deteriorated in nine states, most dramatically in Uttar Pradesh and Orissa.

Collection

The share of energy realized (as revenue) to energy billed was 94 percent in 2011. Collection efficiency has generally remained stable, rising only slightly from 89 percent in 2003. The majority of states now report collection efficiency higher than 90 percent. But ideally, states should be collecting revenue from 100 percent of the energy billed. About half the states saw collection performance worsen over 2003–11. The steepest fall was in Uttar Pradesh, which reported no contribution to utility losses from collection inefficiencies (a collection rate of 100 percent) in 2003 but losses from collection of Rs 32.5 billion (\$0.7 billion) in 2011 (figure 4.11).

States can be put into six groups, based on their tariff setting performance¹¹ and whether the distribution segment makes profits (with or without subsidies) (see table 4.1). Groups 1, 2, and 3 are those where average billed tariffs are below cost-recovery tariff levels. Group 1 states show a balanced budget with subsidies; they also have the highest divergence between subsidies booked and received. Group 2 states do not have cost-recovery tariffs and make losses despite receiving subsidies from the state government. In this case, both tariffs and aggregate technical

Figure 4.11 Losses from Collection



Source: Khurana and Banerjee 2013.

Table 4.1 Tariff Performance and Utility Losses, 2011

Group	Description	States
1	Tariffs are not set at cost recovery but states achieve profits with subsidies	Andhra Pradesh and Rajasthan
2	Tariffs are not set at cost recovery and states make losses with subsidies	Assam, Bihar, Haryana, Punjab, Tamil Nadu, and Tripura
3	Tariffs are not set at cost recovery and states make losses without subsidies	Goa, Himachal Pradesh, Manipur, Mizoram, and Nagaland
4	Tariffs are set at cost recovery but states do not achieve profits even with subsidies	Chhattisgarh, Jharkhand, Karnataka, Madhya Pradesh, Maharashtra, Meghalaya, Orissa, Sikkim, Uttar Pradesh, and Uttarakhand
5	Tariffs are set at cost recovery and state achieves profits with subsidies	Gujarat
6	Tariffs are set at cost recovery and states achieve profits without subsidies	Delhi, Kerala, and West Bengal

Source: Khurana and Banerjee 2013.

Note: Subsidies refers to subsidies booked by the distribution utilities.

and commercial losses need to be addressed. Group 3 states do not receive any subsidies from the state government and do not have cost-recovery tariffs; they thus make losses. These states require the most support from state governments and regulators. Group 4 states have cost-recovery tariffs but still make losses even with subsidies. Most states fall into Group 4, suggesting that operational inefficiencies make the greatest contribution to utility losses. Group 5 includes only Gujarat, which has cost-recovery tariffs and achieves profits with subsidies. And Group 6 states are the best performers—those with cost-recovery tariffs and that achieve profits even without receiving subsidies. That many states make losses despite having average billed tariffs that are at cost-recovery levels underlines the important contribution of above-the-norm distribution losses to total losses.

Tariff Performance on Equity

To assess the performance of tariffs from the equity perspective, two indicators are analyzed—effective tariffs among consumer groups and within tariff categories for domestic consumers.

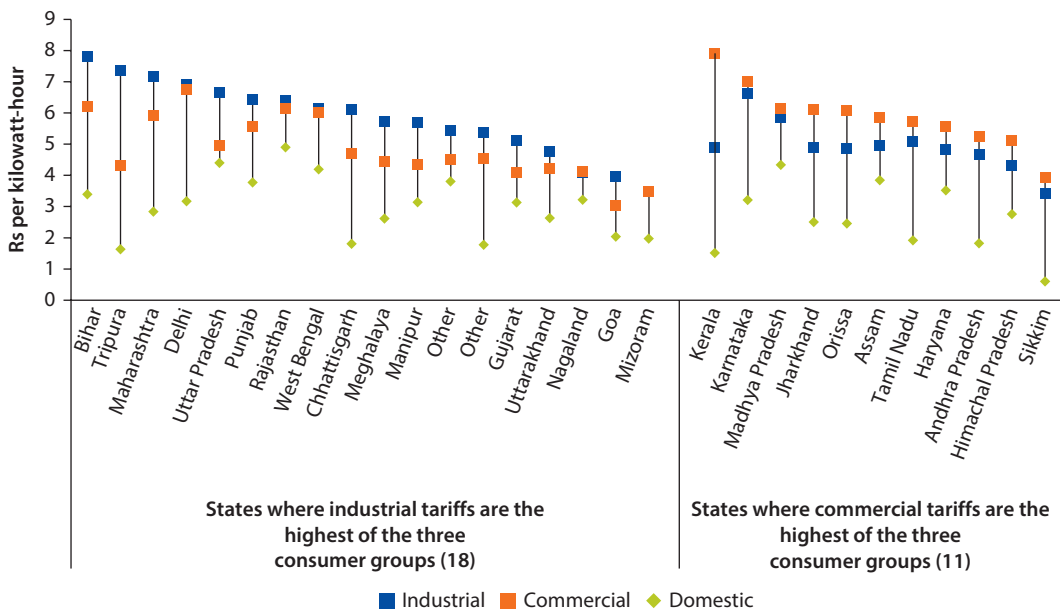
The average billed tariff provides an aggregate estimate of the price at which energy is sold to consumers. A more nuanced way of assessing tariffs would be by consumer group because each group—domestic, commercial, and industrial consumers—is charged differently. Effective tariffs are tariffs calculated at a representative level of consumption (typically the average level) for each group; this generally differs across states. Agricultural consumers are a special category for some states and have their own tariffs.

Effective Tariffs among Consumer Groups

Domestic tariffs are by far the lowest in all states. Industrial tariffs are the highest of the three consumer categories in 18 states, and go up to Rs 8/kWh (\$0.17/kWh) in Bihar. Eleven states have commercial tariffs higher than industrial tariffs. For example, Kerala sets Rs 8/kWh (\$0.17/kWh) for commercial consumers, Rs 5/kWh (\$0.1/kWh) for industrial consumers, and only Rs 1.5/kWh (\$0.03/kWh) for domestic consumers (figure 4.12).

Apart from domestic consumers, the other group that is consistently cross-subsidized is agricultural consumers.¹² Agriculture is a significant share of the consumer base in states that were part of the Green Revolution of the 1960s.

Figure 4.12 Effective Tariffs by Consumer Group, 2012



Source: World Bank compilation.

Because agricultural consumption is largely unmetered and charged estimated rates, losses in other segments are often included in agricultural consumption numbers. Separating agricultural and nonagricultural electricity feeders has been proposed as a technical solution to improve transparency in the sector and potentially enhance the welfare of both farmers and rural domestic consumers while also improving utility performance (box 4.1).

Box 4.1 Improving Rural Supply: Rural Feeder Segregation in Indian States

Power supply to agriculture is heavily subsidized and charged at a flat rate per horsepower per pump. These conditions remove the price incentive for farmers to control their use of power. In response, state utilities seek to limit the power supply to agriculture to six to eight hours a day, often in the evenings. But in most villages, feeders supply both nonagriculture and agriculture loads, so this necessarily also limits the power supply for productive nonagricultural activities and households. Combined feeders prevent utilities from distinguishing between power used for agriculture or for other rural uses or even from monitoring the total amount of power lost (such as through theft and technical inefficiencies).

Several states in India (Andhra Pradesh, Gujarat, Haryana, Punjab, Karnataka, Maharashtra, Madhya Pradesh, and Rajasthan) have launched programs to segregate feeders into rural agricultural and nonagricultural consumers, thus physically separating paid and nominally paid loads. This mechanism enables utilities to measure and limit the amount of power supplied free for agriculture while ensuring that rural nonagricultural consumers receive higher quality supply for longer periods.

The approach to load segregation has varied according to each state's politics, regulatory practices, and power sector development. For example, Haryana has used feeder segregation to address high distribution losses. Rajasthan has tackled it through an integrated Feeder Renovation Programme (which included other system-strengthening works) while Gujarat has addressed it alongside groundwater issues in an integrated rural development approach. The technical approach has also varied. Rajasthan undertook virtual segregation (single-phase supply for all rural households) and Haryana physical (three-phase supply for rural household usage). Andhra Pradesh and Gujarat began with virtual segregation but later shifted to physical segregation.

State approaches to project execution and monitoring were relatively similar. In all cases there was no separate or specific institutional framework in place to execute the scheme. All states other than Haryana undertook a pilot study (many studied Gujarat) before initiating statewide rollout of load segregation. No state included information technology components (remote meter reading and advanced metering infrastructure) to capture metering data online or to implement user-friendly systems to measure and control agricultural consumption. Finally, attention to monitoring and evaluation was negligible in all states; even five years after implementation in Gujarat and Rajasthan, summary reports of agricultural consumption based on the segregated load data were not prepared.

box continues next page

Box 4.1 Improving Rural Supply: Rural Feeder Segregation in Indian States *(continued)*

In Gujarat and Rajasthan (where two subdivisions were studied in depth), load segregation appears to have met its primary objective of increasing the quality and quantity of power for nonagricultural rural consumption. In the Vinchiyaa subdivision of Gujarat, for example, the share of domestic consumers reporting rarely or never experiencing power outages rose from 34 percent to 86 percent after load segregation; the shares of other Gujarat consumers and all consumers in the Bassi subdivision of Rajasthan rose comparably. Similarly, the share of consumers experiencing low voltage fell steeply after load segregation. Load segregation has also likely improved peak demand management and increased rural incomes. But it has not met the objective of accurately measuring agricultural consumption and total power losses, as utility, regulator, and state accounts do not use the data from the new feeders to estimate consumption.

Other key lessons learned from Gujarat and Rajasthan include:

- Segregation is only necessary when agricultural metering cannot be adopted. If possible, solutions such as advanced metering infrastructure can be used instead of load segregation to limit supply to farmers. Without agricultural metering, load segregation alone does not enable estimation of theft.
- Load segregation does not necessarily require additional infrastructure. If current infrastructure is aged and overloaded, load segregation can be achieved through the infrastructure replacement that would have occurred anyway.
- Feeder segregation is not a one-time investment but rather an ongoing activity that requires continuous monitoring and enforcement to ensure that new connections are introduced on the appropriate feeders.

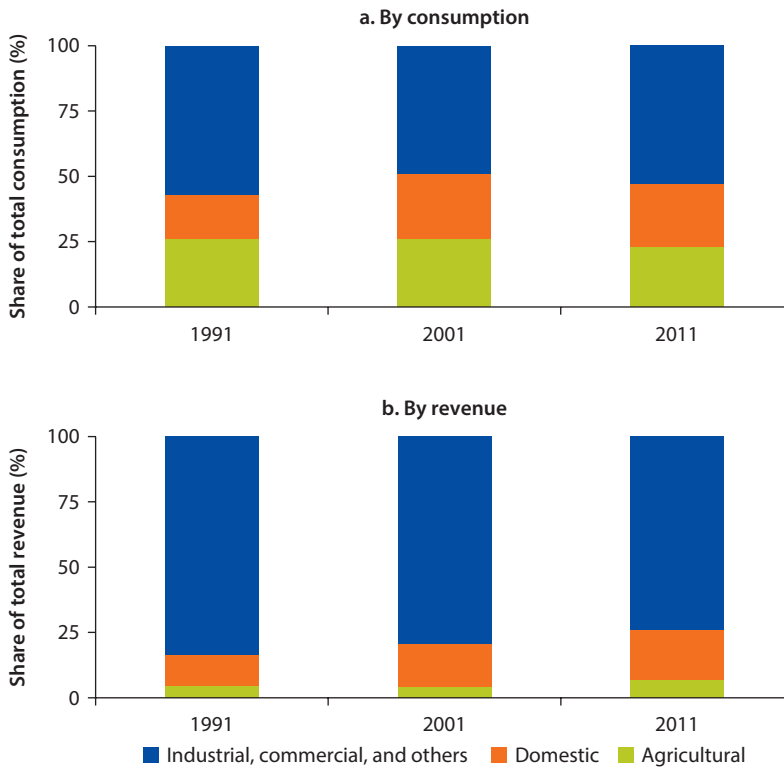
Source: World Bank 2013.

Since 1990 agriculture has accounted for about 25 percent of total electricity consumption, but it contributed only 4 percent of total revenue of distribution utilities until 2001 and about 7 percent as recently as 2011 (Sharma 2005; Planning Commission 2001, 2011; see also figure 4.13).

Effective Tariffs within Categories of Domestic Consumers

There is inequity across consumption levels, stemming from the prevalence of fixed charges or minimum consumption charges. These charges have a stark impact on households consuming less than 30 kWh a month (which constitute 29 percent of all households below the poverty line). In 21 states the average household consuming less than 30 kWh a month pays more per unit of electricity than the average household consuming 30–100 kWh a month. In 10 of those states (Bihar, Delhi, Haryana, Himachal Pradesh, Jharkhand, Manipur, Orissa, Rajasthan, Uttarakhand, and Uttar Pradesh), the average household consuming less than 30 kWh a month pays more per unit of electricity than even the average household consuming more than 300 kWh a month. In four states (Haryana, Kerala,

Figure 4.13 Consumer Mix Overview in 1991, 2001, and 2011



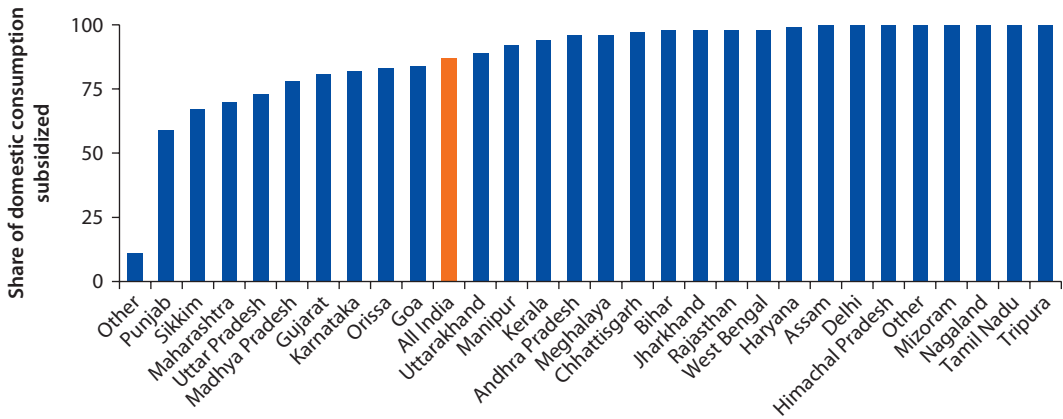
Source: Planning Commission 2011.

Nagaland, and Punjab), this regressive tariff design is specifically caused by minimum charges, affecting 11–34 percent of households in those states.

Tariff subsidies are widely prevalent. In most state tariff schedules, most electricity units are priced below average cost (subsidized) and very few are priced above cost (that is, provide a cross-subsidy to other users). The volume of electricity units priced below cost indicates subsidy prevalence. About 87 percent of all electricity units consumed by domestic consumers are subsidized (figure 4.14). As the domestic sector consumes almost a quarter of electricity sold, this was equivalent to 21 percent of all electricity consumed in India in 2010.¹³ The remaining 13 percent of domestic electricity consumption is priced above average cost. In states such as Assam, Delhi, Himachal Pradesh, Nagaland, Tamil Nadu, and Tripura, essentially all domestic electricity is sold at below cost-recovery tariffs. Nineteen states subsidize more electricity than the all-India average (87 percent). For these states to recover costs, the cross-subsidies generated by the few units priced above average cost would have to be far larger than the subsidies on the many subsidized units. One state is an extreme outlier, subsidizing only 11 percent of domestic consumption (figure 4.14).

Figure 4.14 Subsidy Prevalence by State, 2010

Percent



Source: Mayer, Banerjee, and Trimble 2013.

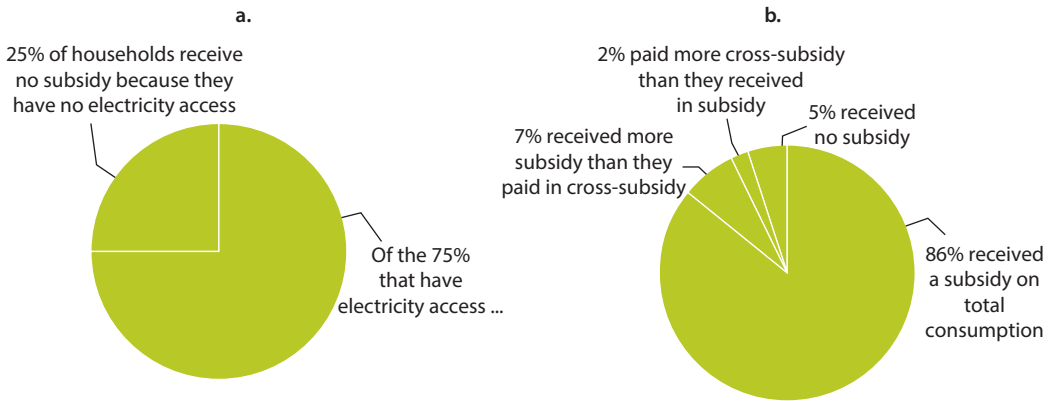
Tariff subsidies are also large.¹⁴ Across the 87 percent of subsidized units, the average subsidy is Rs 1.5 (\$0.003) per kWh. Across the 13 percent of units generating a cross-subsidy, the average cross-subsidy is only Rs 0.62 (\$0.013) per kWh. And in almost all states the average subsidy is larger than the average cross-subsidy. Mizoram provides the starkest contrast: its subsidized units receive an average subsidy of Rs 3.5 (\$0.075) per kWh, and none of its units provides a cross-subsidy. Only in Uttarakhand, Haryana, Manipur, and Andhra Pradesh is the average cross-subsidy larger than the average subsidy. In almost all states the share of units charged at a cross-subsidy rate is too low to recover costs in aggregate even with the higher average cross-subsidy.

About 93 percent of connected households receive more in subsidies than they pay in cross-subsidies. Consumers can be put into four groups based on subsidy status (figure 4.15):

- *Group 1 (full subsidy)*. Some 86 percent of all electrified households receive a subsidy on total consumption.
- *Group 2 (net subsidy)*. Seven percent receive more in subsidies than they pay in cross-subsidies.
- *Group 3 (net cross-subsidy)*. Two percent receive some subsidies but pay cross-subsidies on the net consumption.
- *Group 4 (no subsidy)*. Five percent do not receive subsidies on any consumption.

Despite this generous subsidy regime, most of the domestic tariff subsidies are *not* reaching the poor. In 2010 some 87 percent of subsidy payments India-wide were delivered to households above the poverty line (figure 4.16). Accounting for cross-subsidy payments improved this figure by less than half

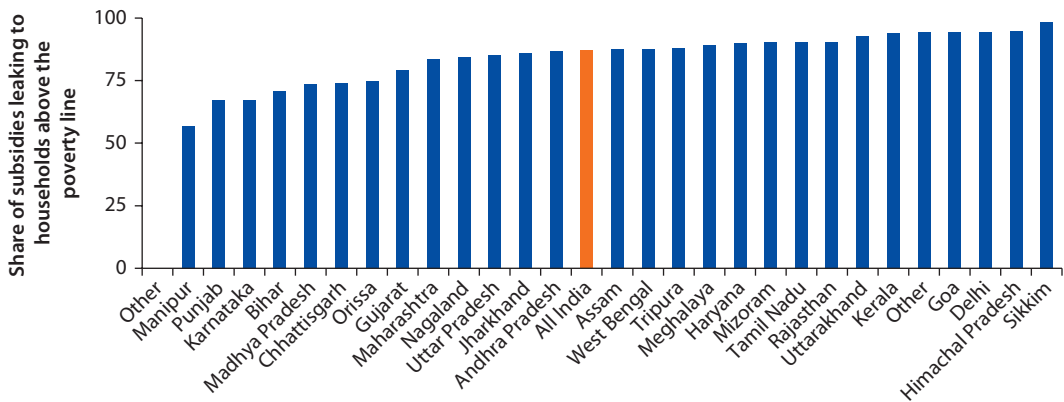
Figure 4.15 Household Subsidy Coverage, 2010



Source: Mayer, Banerjee, and Trimble 2013.

Figure 4.16 Subsidies Leaking to Households above the Poverty Line, 2010

Percent



Source: Mayer, Banerjee, and Trimble 2013.

a percentage point. In 11 states more than 90 percent of all subsidy payments were delivered to households above the poverty line. Only one state was successful in targeting subsidies to the poor, with no leakage (figure 4.16).

A variety of factors drives this subsidy distribution. In most states all households are eligible for a subsidy on at least some of their consumption; households below the poverty line have considerably lower levels of consumption than households above it; and households below the poverty line have a disproportionately lower electricity access rate than households above it. The first two factors mean that electrified households above the poverty line are typically eligible for just as much of a subsidy as electrified households below the line, if

not more. The third factor means relatively more households below the poverty line are ineligible for a subsidy than households above it.

Low access rates in the poorer income quintiles make subsidy targeting a challenge. With the typical increasing block tariff structure, all households pay the same low rate on their initial consumption. This necessarily means that higher-consuming (usually richer) households consume as much or more of the initial subsidized electricity units as lower-consuming (usually poor) households and will therefore always receive as much or more in subsidy payments. The seven states with the least leakage of subsidies all have separate tariff schedules for households below the poverty line.

Benchmarking Utilities on Financial and Operational Indicators

There are significant differences among discoms on both financial and operational indicators, and some have persisted for many years. The heterogeneity of performance between the top 10 and bottom 10 utilities (each set of 10 represents about 20 percent of the sample) brings this sharply into focus. For this analysis, six indicators—three financial (profit after tax with subsidy, accumulated losses, and ratio of revenue to operating cost) and three operational (distribution loss rate, collection efficiency, and debtor days)—are analyzed over 2003/04–2010/11, divided into two equal time frames—2003/04–2006/07 and 2007/08–2010/11 (figure 4.17).

Indicators have evolved in different ways over time. For profit after tax and accumulated losses, while the top 10 companies held steady, the fall in performance of the bottom 10 companies was precipitous between 2003/04 and 2010/11. The divergence across top and bottom performers in distribution losses and debtor days has been somewhat less. Over the same period, the difference in recovery of operating cost and collection efficiency narrowed.

Some discoms are consistently strong over many years and across multiple indicators.¹⁵ Tata Power in Delhi stands out: over 2003/04–2006/07 it was in the top for two of the three financial indicators and one of the three operational indicators; over 2007/08–2010/11 it was in the top for all three financial indicators and two of the three operational indicators. Other utilities that stood out were Kerala's state electricity board (SEB; box 4.2) and Goa's power department.

Several utilities persistently rank among the poorest performers over time, often on both financial and operational indicators: included among them are Dakshinanchal and Poorv Vidyut Vitran Nigams in Uttar Pradesh, and the power department in Manipur. Punjab's SEB and unbundled discom were among the bottom on financial indicators (particularly over 2007/08–2010/11) but not on operational indicators. Bihar's SEB and the Kanpur Electricity Supply Company in Uttar Pradesh were among the bottom on multiple operational indicators in both periods but not on any financial indicators.

In addition to the simple comparison among discoms described above, a tool based on the analytic hierarchy process (AHP) can be used to monitor performance

of state power distribution utilities (box 4.3). This method is particularly relevant as it surveys selected experts from banks and financial institutions to make a pairwise comparison of 11 factors important for power sector lending that capture the sector’s financial and operational performance. The process is flexible as it permits the introduction of new variables as relevant. The results also align with the integrated ratings methodology adopted by the Ministry of Power in 2013. Using the AHP will require finessing on threshold values—at what point does a state or the Ministry of Power ring warning bells on performance?

Figure 4.17 Evolution of Performance of Top and Bottom Discoms, 2003/04–2010/11

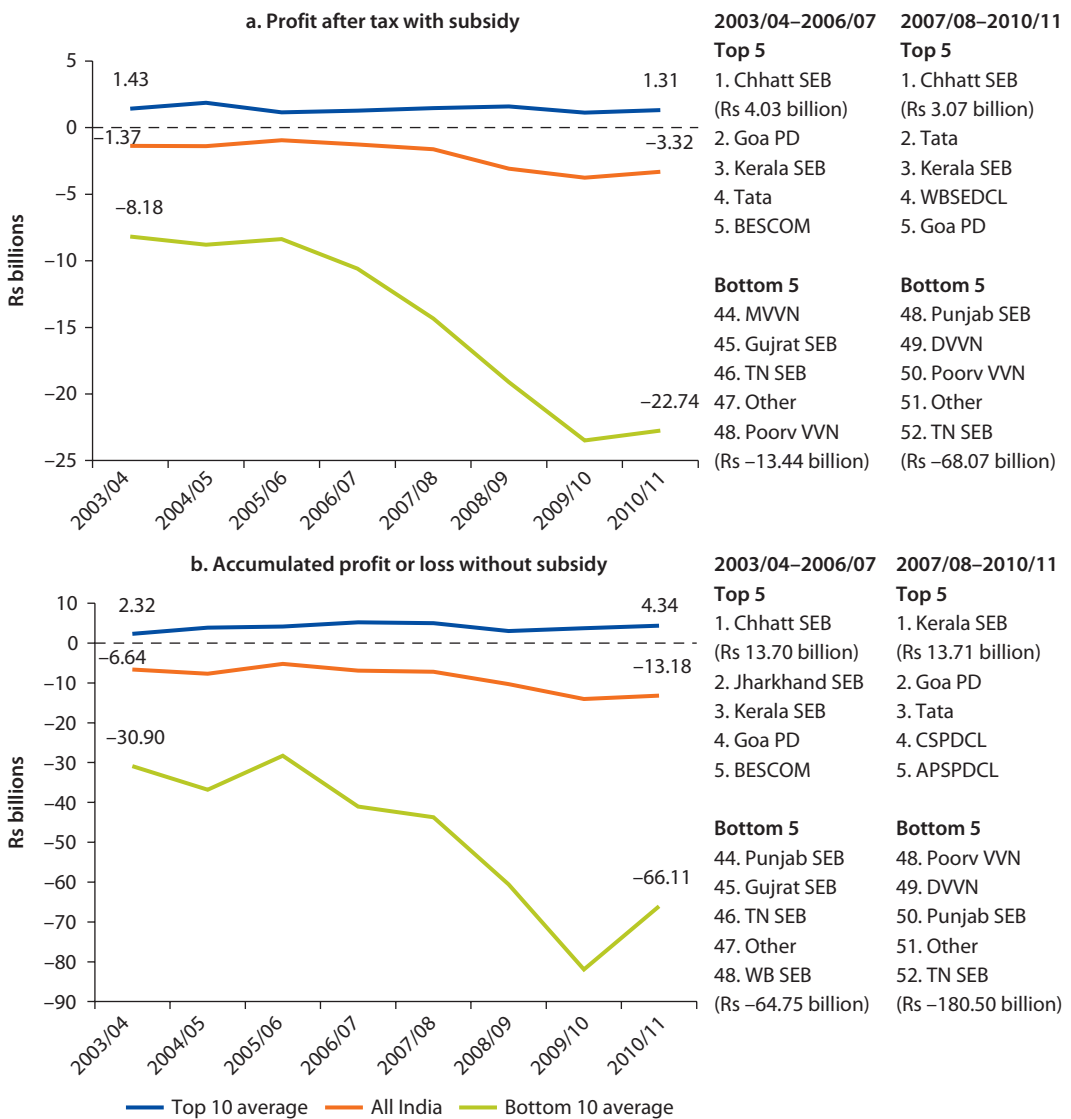


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Figure 4.17 Evolution of Performance of Top and Bottom Discoms, 2003/04–2010/11 (continued)

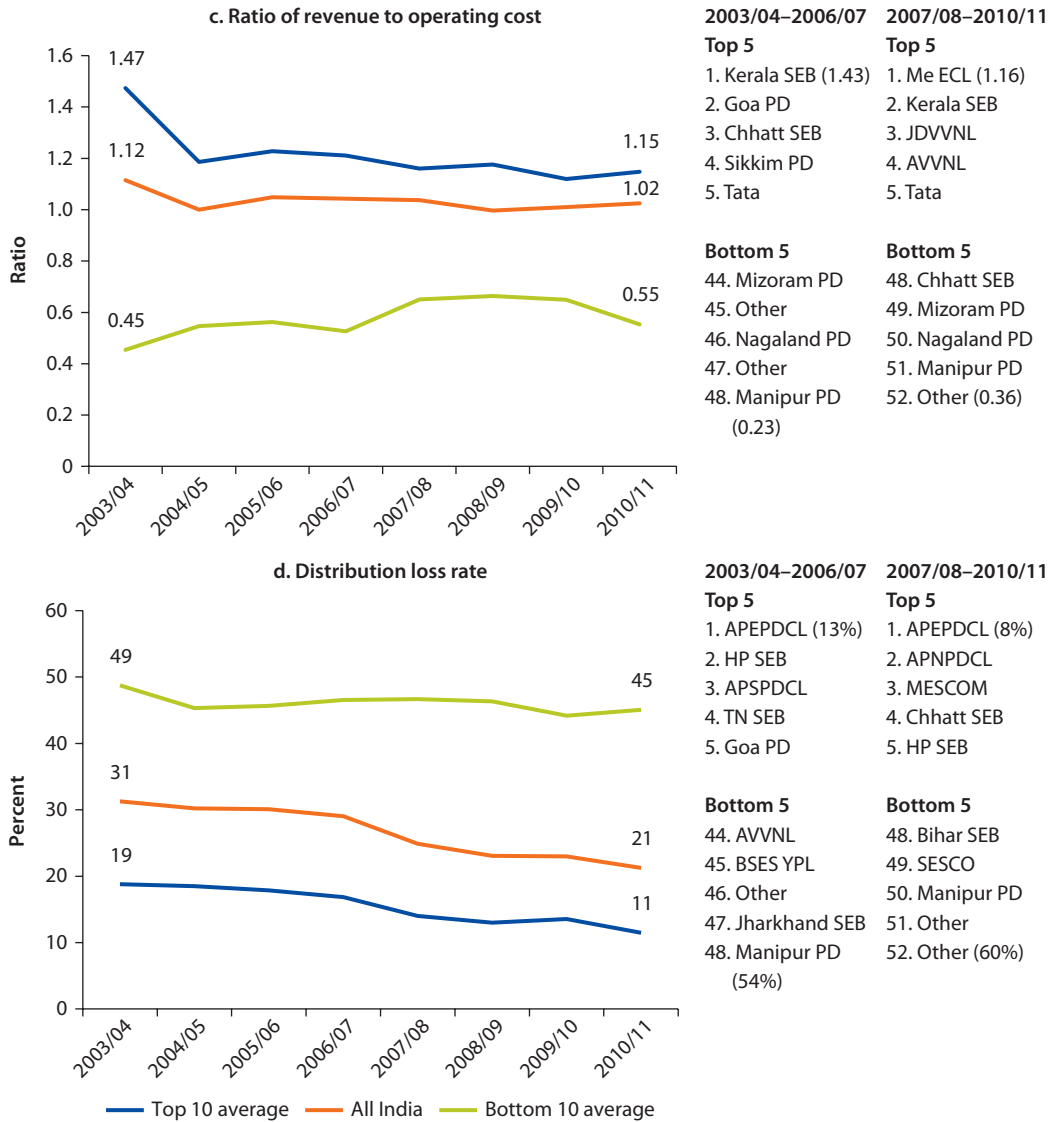


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Figure 4.17 Evolution of Performance of Top and Bottom Discoms, 2003/04–2010/11 (continued)



Source: Khurana and Banerjee 2013.

Note: The specific distribution companies falling in the top and bottom 10 change from year to year.

Box 4.2 Kerala—A Successful State Electricity Board

Kerala is considered to have one of India’s best performing electricity sectors. According to Power Finance Corporation data for 2003–11 on utilities directly serving consumers, the Kerala State Electricity Board (KSEB) consistently ranks among the top utilities in India. In 2011 the KSEB had the highest accumulated profits and ranked third on profit after tax. Aggregate technical and commercial (AT&C) losses were 14 percent, which is the seventh lowest among

box continues next page

Box 4.2 Kerala—A Successful State Electricity Board *(continued)*

all distribution utilities. And transmission and distribution losses declined consistently every year after 2001. All connections are metered and theft of electricity is practically nonexistent. In 2010 Kerala received the National Energy Conservation Award for its efforts in this field.

External Factors in Kerala's Success

An abundant supply of water and rainfall means that Kerala's farmers are not dependent on electric pumps to irrigate their farms. Indeed, agriculture accounts for less than 5 percent of the consumer base and 2 percent of total energy billed. This natural advantage means that the KSEB does not face a high agricultural subsidy burden, unlike many other utilities.

Supply constraints forced the KSEB to look for efficiency improvements elsewhere in the system. Inexpensive hydropower was initially the catalyst for economic growth. But environmental constraints have diminished the state's capacity to further exploit its hydro potential, and Kerala went from being an energy-surplus state in the 1980s to an energy-deficit state by the mid-1990s. More than 70 percent hydro, the state's installed capacity has actually declined with the decommissioning and de-rating of older plants. However, a positive side-effect was that Kerala had to focus increasingly on improving the efficiency and performance of its transmission and distribution infrastructure while simultaneously pursuing demand-side management.

State Efforts to Strengthen the Power System

Kerala has strengthened its power system and reduced AT&C losses, though for political reasons it has not unbundled the KSEB as mandated under the Electricity Act of 2003. Key aspects that have contributed to its sound track-record include the following.

- *Effective State Regulator.* Established in 2002, the Kerala State Electricity Regulatory Commission has grown into an effective regulatory agency. It has diligently issued tariff orders in 10 of the last 13 years (making it fifth among all states). It also increased tariffs in three of the last six years (2005/06, 2007/08, and 2012/13) and was awarded the Independent Power Producers' Association of India Power Award for best state electricity regulatory commission in 2013.
- *Investment in Network Strengthening.* The KSEB has consistently invested in its subtransmission and distribution network not only to expand it but also to incorporate information technology infrastructure. The biggest success story in transmission has been establishing a state-of-the-art state load dispatch center using supervisory control and data acquisition and associated communications infrastructure. The KSEB has adopted load-flow software for transmission-system planning and has taken up substantial works under the Accelerated Power Development and Reform Programme, Restructured Accelerated Power Development and Reform Programme, and Rajiv Gandhi Grameen Vidyutikaran Yojana programs for augmenting its distribution network. Various demand-side management and energy-efficiency initiatives have also been successfully implemented.
- *A Focus on Metering, Billing, and Customer Service.* Kerala has 100 percent metering; older electro-mechanical meters are being replaced with modern tamper-proof electronic models. The KSEB has sound systems and processes for maintaining a healthy revenue

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Box 4.2 Kerala—A Successful State Electricity Board *(continued)*

billing and collection cycle. Excellence in revenue management is also a function of the sound payment culture in most of Kerala. Thirteen Power Anti-Theft Squads have been set up under the anti-theft and vigilance wing of the KSEB, headed by a deputed senior police officer. District courts have been notified as special courts to deal with cases of power theft. In addition, the KSEB is modernizing its systems. It uses internally developed software for customer-friendly electric billing and accounting, and has built an online portal for consumer payments and grievance redressal. These efforts have improved service quality, billing efficiency, transparency, and financial savings. The KSEB's collection efficiency of 97 percent in 2010/11 attests to the initiatives' payoffs.

- *Investment in Employees.* The KSEB is working to improve employee efficiency and satisfaction. There are now four human resources committees to oversee promotions and transfers. And it has improved grievance-redressal and pension plans for employees. The KSEB also offers well-designed technical, information technology, and financial training to all officers and staff.

But since 2011 KSEB's finances have been constrained due to the state's declining hydro generation, forcing the utility to purchase power from external sources and draw down surpluses earned in earlier years. Inadequate planning for power procurement to address demand growth has exacerbated the change in fortunes of the utility, which remains well managed but is now suffering in the face of external shocks.

Box 4.3 Design of a State Performance Index Using the Analytic Hierarchy Process

The analytic hierarchy process (AHP) was used to create a state performance index. Selected experts from financial institutions and banks were asked to compare the various factors identified below for the purposes of lending to the power sector. There are around 12 major lenders to power sector utilities in India (including private banks, government banks, and financial institutions like the Rural Electrification Corporation and Power Finance Corporation). Five of these lenders were selected for this exercise.

The 11 factors used for this analysis are:

- Gap after subsidy [(average cost – average revenue)/average cost].
- Subsidy/total cost.
- Subsidy received/subsidy booked.
- Transmission and distribution losses.
- Collection efficiency.
- Debtor days.
- Creditor days.
- (Accumulated losses + subsidy)/current average cost.
- Future gap in 2017.

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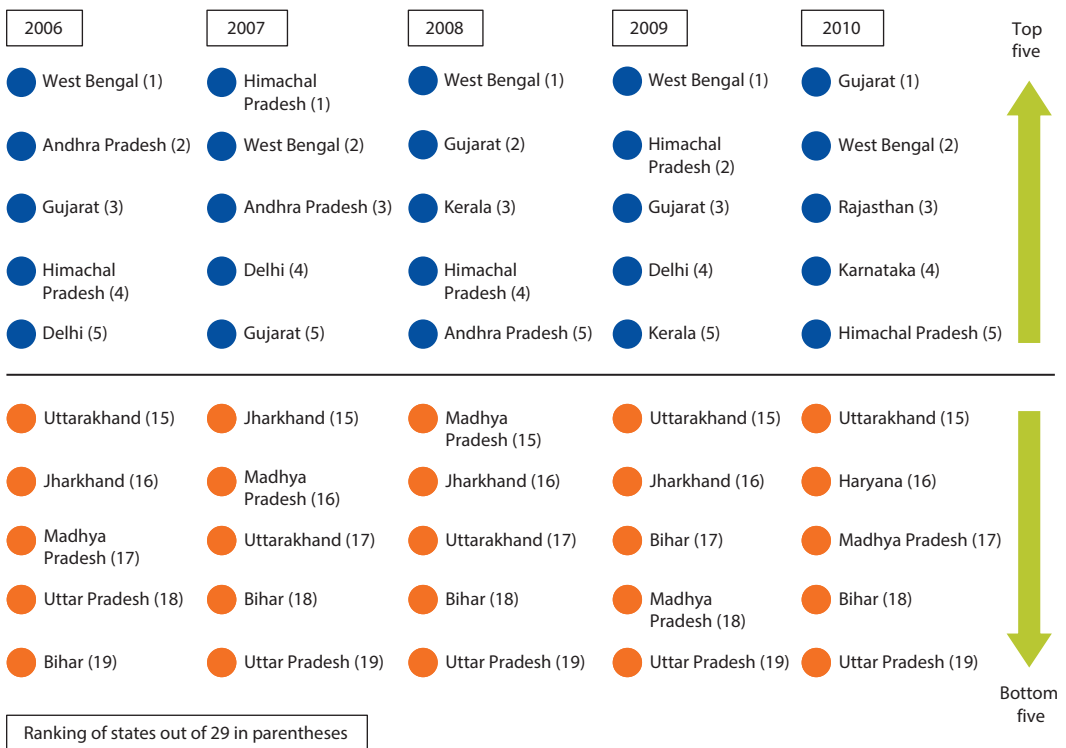
Box 4.3 Design of a State Performance Index Using the Analytic Hierarchy Process *(continued)*

- Energy deficit.
- Power purchase cost per unit.

The survey started with a larger set of variables. But these 11 variables, all quantitative, were found to be representative of the aspects captured by other variables. The outcome of the AHP is based on the perceptions of experts.

Source: Khurana and Banerjee 2013.

Figure 4.18 Best and Worst Performing States in the Analytic Hierarchy Process Index, 2006–10



Source: Khurana and Banerjee 2013.

Once such values are arrived at, the AHP is a promising complementary tool to the ratings methodology adopted by the ministry.

The AHP method was used to create a baseline of annual sector performance for 2006–10. The baseline results have Gujarat, West Bengal, and Himachal Pradesh occupying the top spots during these five years, with some movement among them (figure 4.18). Kerala has reported steady improvement during the period in its debtor and creditor days as well as considerable improvement in its subsidy-received-to-booked ratio in 2008. Kerala and Karnataka have emerged as

reasonable performers on both technical and commercial parameters included in the AHP index. Of the two, Karnataka has worse financial performance (a large amount of debtor days), but it has improved in the last two years.

Uttar Pradesh, Bihar, and Madhya Pradesh remained the worst performers over the five years. Bihar and Jharkhand fared poorly on most efficiency parameters (debtor days, collection efficiency, and transmission and distribution losses). These states would gain tremendously from cash collections to reduce debtor days from current abnormally high levels. In Bihar and Jharkhand several power stations are either shut or operating at abysmal efficiency. Haryana and Punjab exhibit high financial losses: of the two, Haryana performs worse than Punjab on generation and distribution; Punjab lags on power purchase costs and tariff revisions.

Notes

1. Total revenue is calculated as collected revenues from sale of power plus trading and other revenues.
2. Hydro-thermal mix, share of purchases from outside the state, and the costs of these out-of-state purchases, and so forth.
3. Stochastic frontier analysis is an econometric (parametric) method that estimates a cost or production frontier. The method is used to estimate the efficient frontier and efficiency scores. Because of its statistical nature, stochastic frontier analysis allows for the inclusion of stochastic errors in the analysis and testing of hypotheses. However, computations using this method are relatively complex and are highly dependent on the assumptions made in constructing the functional form for the utilities.
4. Data envelopment analysis is a linear programming methodology to measure the efficiency of multiple decision-making units when the production process presents a structure of multiple inputs and outputs. This method is commonly used for measuring the performance of similar utilities for which the presence of multiple inputs and outputs and nondiscretionary variables makes comparisons difficult. The approach identifies an efficient frontier made up of the most efficient firms in the sample and measures the efficiency scores of the less efficient firms in relation to the most efficient.
5. National average operating heat rate was 2,615.4 kilocalories per kWh in 2010 (CEA 2010).
6. The station heat rate of the Dahanu Plant was 2,285 kilocalories per kWh in 2010.
7. Although the utility is required to pay fixed costs for the use of third-party plants, because such plants are partially or wholly stranded for lack of coal, the saving for India is the entire amount, not just the net saving for the utility. Further, if the coal is used in another partially used plant of the utility (or where the utility has a share and is paying fixed costs for underused capacity), the entire saving would be to the account of the utility.
8. The difference between cost and revenue = profit before tax.
9. This tariff level would cover (exceed) average cost, but unless the utility had distribution losses of less than 10 percent *and* 100 percent collection, it would not break even by charging a tariff equal to average cost.

10. The average billed tariff is revenues billed/energy sold.
11. Whether the average billed tariff is higher than the cost-recovery tariff level.
12. This topic has been studied in detail by a recent World Bank report on how delivering agriculture subsidies can be made more efficient (Gulati 2013).
13. This is a minimum share of electricity that was subsidized. Most agricultural consumption, as well as some commercial and potentially industrial consumption, is also subsidized, so the actual share of subsidized consumption is probably much higher.
14. The difference between the cost and tariff on subsidized units indicates the subsidies' size, while the difference between the cost and tariff on the cross-subsidized units signals the size of the cross-subsidies.
15. To identify these discoms, each discom's value for an indicator was averaged (without weights) over two periods: 2004–07 and 2008–11. Discoms were then ranked by period and indicator. For states that unbundled within a period, the unbundled discom values were summed (for profit after tax and accumulated losses) or averaged (for the other indicators) and applied to the state electricity board (SEB), and only the SEB was included in the sample.

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Implementing Sector Reforms

Because the power sector is a concurrent subject under the constitution, states are responsible for implementing the centrally designed mandates of the Electricity Act of 2003 (EA 2003, or EA) and its associated policies. This chapter describes an “implementation of reforms” index that assesses progress in executing the EA’s six major focus areas. Index scores suggest that reform implementation has been uneven. States have advanced the least in promoting competition, while they have advanced the most in enhancing quality and affordability and in expanding access. Delhi has made the most progress in implementing the EA’s agenda, followed by Gujarat, Maharashtra, Madhya Pradesh, and Andhra Pradesh.

The chapter also describes a “sector outcomes” index that assesses the achievement of sector performance targets relevant to consumers, investors, and the government. Here, too, results are uneven. Gujarat and Punjab rank highest on achieving outcomes.

Together, the indexes show that achievement of sector outcomes closely reflects the extent to which each state has implemented the EA reforms.

Implementation of Reforms Index

To effectively implement EA mandates requires not just adhering to the letter of the legislation but also following up to ensure that each reform has its intended effect. The implementation of reforms index attempts to move away from mere “check-the-box” actions, such as notification of various sector regulations, to examine tangible actions that reflect meaningful progress and true commitment to an improved power sector. The index measures the actions by governments, regulatory commissions, and utilities to realize the objectives of the EA and its associated policies.

The implementation of reforms index comprises six subindexes, reflecting six EA focus areas (see box 1.1 in chapter 1):

- Introduction of competition (“competition”).
- Enhanced accountability and transparency (“accountability and transparency”).

- Cost recovery and commercial viability (“cost recovery”).
- Access to electricity and rural electrification (“access”).
- Improved quality of service and affordability of supply (“quality and affordability”).
- Promotion of renewable energy (“renewable energy”).¹

Each subindex aggregates performance with respect to between one and four objectives of the associated reform area. Simple unweighted averages are used to calculate the subindexes and to obtain an overall measure of implementation of reforms. For each objective several implementation parameters are considered to measure progress toward that objective. Scores on each implementation parameter are averaged to obtain scores for each objective; scores for each objective are averaged to obtain scores for each reform area; and scores for each reform area are averaged to obtain an overall score.

The objectives and indicators (implementation parameters) considered for each subindex are in table 5.1. Many indicators are considered across several years,

Table 5.1 Implementation of Reforms Index

<i>Reform area</i>	<i>Objective</i>	<i>Implementation parameter</i>
Competition	Sector unbundling	Years since unbundling
	Open network access	Notification of open access regulations
		Cross-subsidy reduction from 2008/09 to 2012/13
	Scheduling discipline	Implementation of availability-based tariffs
Competitive procurement	Use of Case 1 or Case 2 processes	
Accountability and transparency	Regulatory oversight	Notification of key regulations
		Special courts for electricity theft
		Special police stations for electricity theft
		State advisory committee
	Regulator independence	Public tariff hearings
		State electricity regulatory commission revenue source
	Utility corporatization	Public availability of state electricity regulatory commission accounts
		Finalization of staff transfer
		Autonomous cash management
		Share of board that is executive directors
Cost recovery	Tariff-setting mechanism	Share of board that is independent directors
		Audit committee
		Frequency of tariff orders from 2000/01 to 2012/13
		Delay in tariff issuance from 2000/01 to 2012/13
	Efficiency improvement	Frequency of tariff hikes from 2007/08 to 2012/13
		Issuance of multiyear tariff order
		Use of fuel and power purchase cost adjustment mechanism
		Coverage under R-APDRP
Subsidy institutionalization	Share of approved R-APDRP funds released	
	Share of booked subsidies received from 2005/06 to 2012/13	

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Table 5.1 Implementation of Reforms Index (continued)

<i>Reform area</i>	<i>Objective</i>	<i>Implementation parameter</i>
Access	Access and rural electrification	Village electrification status
		Share of nonelectrified villages electrified from RGGVY inception through 2011/12
		Share of electrified villages intensively electrified from RGGVY inception through 2011/12
		Share of nonelectrified rural households connected from RGGVY inception through 2011/12
		Share of nonelectrified households below the poverty line connected from RGGVY inception through 2011/12
Quality and affordability	Service standards	Consumer grievance redressal forum regulations notified
		Ombudsman appointed
		R-APDRP information technology coverage
Renewable energy	Reducing retail tariffs through reduced leakages	Debtor days
	Mandatory renewable energy purchases	Instances of achievement of aggregate technical and commercial loss reduction target from 2003/04 to 2010/11
Renewable energy	Renewable energy capacity development	Number of future years for which Renewable Purchase Obligation targets defined
		Renewable energy certificate regulation notified
		Share of identified renewable energy sources for which feed-in tariffs notified

Source: Deloitte 2013.

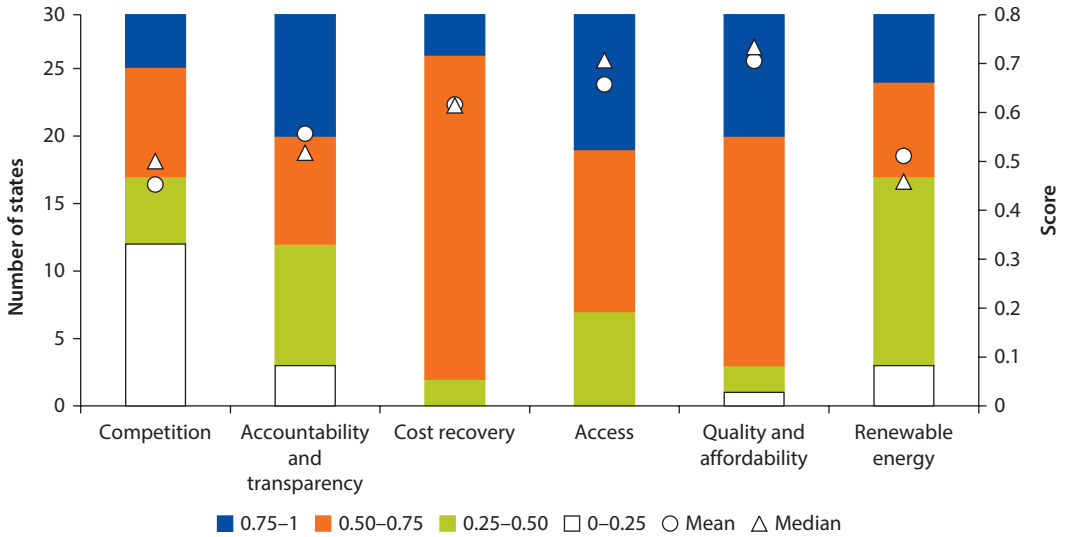
Note: R-APDRP = Restructured Accelerated Power Development and Reform Programme; RGGVY = Rajiv Gandhi Grameen Vidyutikaran Yojana.

in which case the years of consideration are given. Otherwise, if not indicated, the data are as of 2011/12.

The average implementation score across all states was 0.54, suggesting that most states have completed half the reform actions envisaged. Among the reform areas, service quality and affordability has seen the most progress, with a statewide average score of 0.71, followed closely by access, on which three-quarters of states scored above 0.50 (figure 5.1). The statewide average was by far the lowest for competition, a cornerstone of the EA, in which almost half the states scored below 0.25. Of the five implementation parameters used to measure progress in promotion of competition (see table 5.1), only two have been implemented by most states: notification of open access regulations (all but 2 states) and unbundling (18 states). Thirteen states have reduced cross-subsidy surcharges over the last five years. Only 10 states have initiated competitive power procurement, and only 8 have begun implementing availability-based tariffs, beyond notifying availability-based tariff regulations. Delhi achieved the highest score on overall reform implementation (0.83), closely followed by Gujarat (0.81) and Maharashtra (0.78).

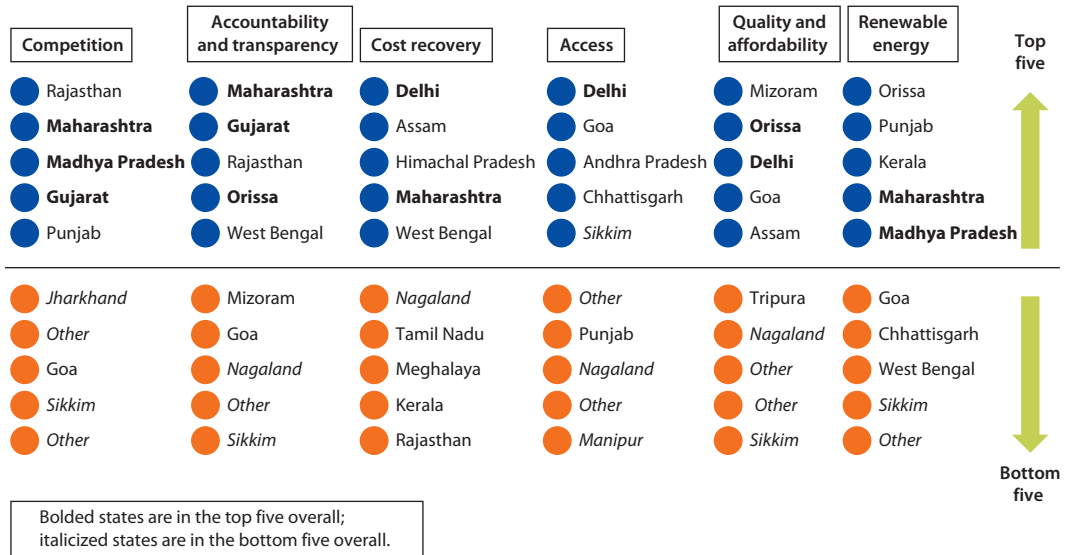
State scores on the reform subindexes underline that implementation of reforms has been strikingly uneven (figure 5.2). Most states have made

Figure 5.1 State Performance on Reform Areas



Source: Deloitte 2013.

Figure 5.2 Progress on Reform Implementation—Top Five and Bottom Five States by Reform Area



Source: Deloitte 2013.

Table 5.2 Sector Outcomes Index

<i>Stakeholder</i>	<i>Objective/expectation</i>	<i>Performance indicator</i>
Customers and citizens	Power availability	Gap between electricity demand and supply
	Efficient service delivery	Aggregate technical and commercial losses
	Affordable power	Average difference between cost of supply and subsidy from 2005/06 to 2010/11
State government	Reduction in burden to exchequer	Reduction in subsidy support per unit of input energy from 2005/06 to 2010/11
	Access to electricity	Household electrification rate
	Environmental concerns	Solar renewable purchase obligation compliance Share of identified nonsolar renewable energy potential harnessed
Investors and lenders	Sector openness	Extent of private sector participation in installed generation capacity
		Extent of private sector participation in planned generation capacity additions
		Extent of private sector participation in distribution
	Sector viability	Trend in cash losses per input unit 2005/06–2010/11
		Debt-to-equity ratio
		Average net profit margin from 2005/06 to 2010/11
Competition in last-mile delivery	Share of open access applications implemented	
	Number of transactions on power exchanges	

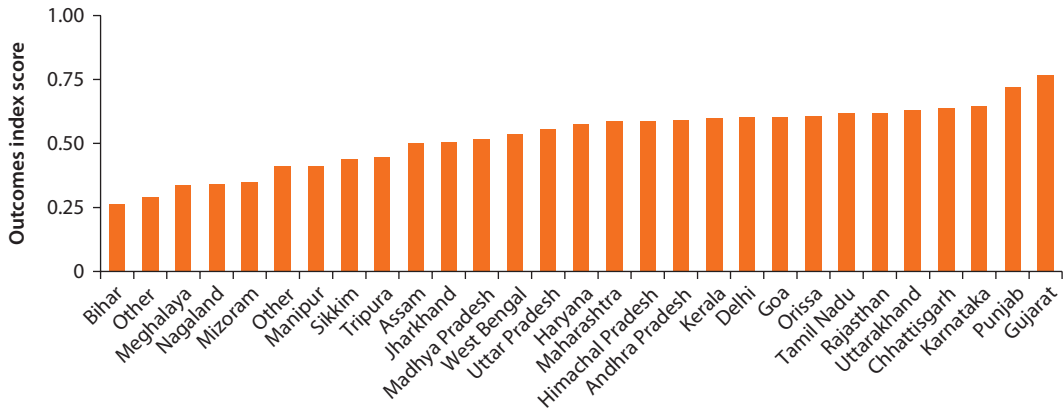
Source: Deloitte 2013.

nominal progress on the stated reform areas: all have established electricity regulatory commissions, and almost all have notified open access regulations. But many of the follow-through actions that give impact to these reforms have yet to be tackled. For example, few states have utilities with an adequate share of independent directors on their boards. While 19 states have determined all of the required charges for open access, only 13 have made the cross-subsidy reductions necessary for open access to take effect. And few state electricity regulatory commissions are financially autonomous from their state governments.

While not the highest scoring state on overall reform implementation, Maharashtra has pushed strongly on implementation across a wide range of reforms: it is among the top five states in implementation in four areas (competition, cost recovery, accountability and transparency, and renewable energy). It is followed by Delhi and Orissa, which are among the top five states in three areas each (see figure 5.2).

Sector Outcomes Index

The significant variation across states in implementing EA reforms indicates that the outcomes expected from the reforms are unlikely to be fully realized. To test this hypothesis, a sector outcomes index was constructed to measure progress on the various power sector outcomes that the reform agenda was

Figure 5.3 State Progress on Expected Outcomes

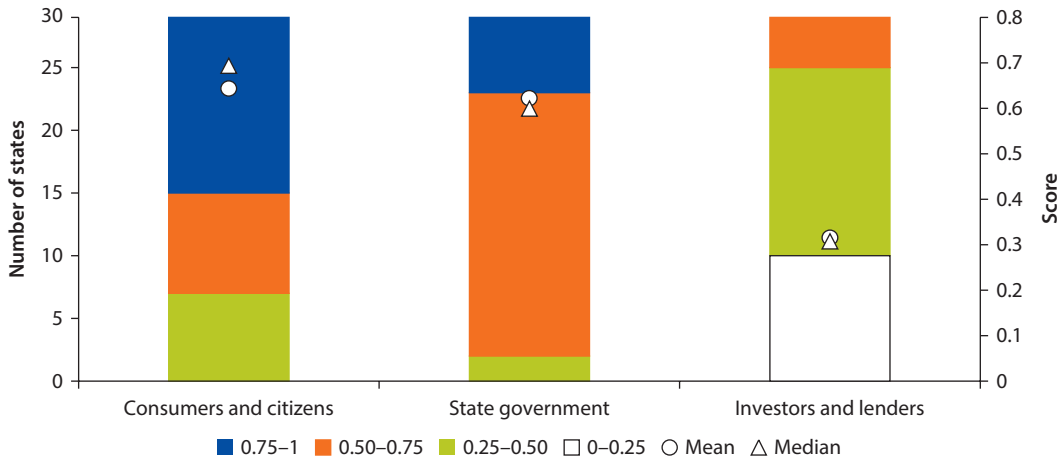
Source: Deloitte 2013.

expected to achieve. The index is divided into three subindexes reflecting the objectives and expectations of the sector's three key stakeholders—customers and citizens, the state government, and investors and lenders (table 5.2). Performance indicators have been identified to measure progress in achieving these objectives. Scores on each performance indicator are averaged to obtain scores for each objective; scores for each objective are averaged to obtain scores for each stakeholder subindex; and scores for the stakeholder subindexes are averaged to obtain an overall score, with unweighted averages used at each level of aggregation.

State progress in achieving the outcomes expected from the reforms has varied. Several states have nearly achieved the goal of universal access, while others are far from achieving it. Some states have successfully reduced aggregate technical and commercial (AT&C) losses to meet the goal of 15 percent, yet the all-India average AT&C loss remains at about 26 percent. Subsidies persist in many states, though several states have greatly narrowed or even closed the gap between tariffs and the cost of supply. Gujarat and Punjab achieved the highest scores on the overall outcomes index—0.77 and 0.72 (figure 5.3). The average score across all states was 0.53.

States showed the most progress on outcomes of interest to customers and citizens, with an average score of 0.64 (figure 5.4). Of these performance targets, most states reduced the gap between power demand and supply, though in nine states the demand-supply gap remained above 10 percent through 2012. States did less well in reducing consumer retail tariffs to more affordable levels. The average score on the subindex of outcomes most relevant to the state government was 0.62. Strong state performance on these outcomes was driven by a reduction in the burden on the

Figure 5.4 State Performance on Sector Outcomes Subindexes



Source: Deloitte 2013.

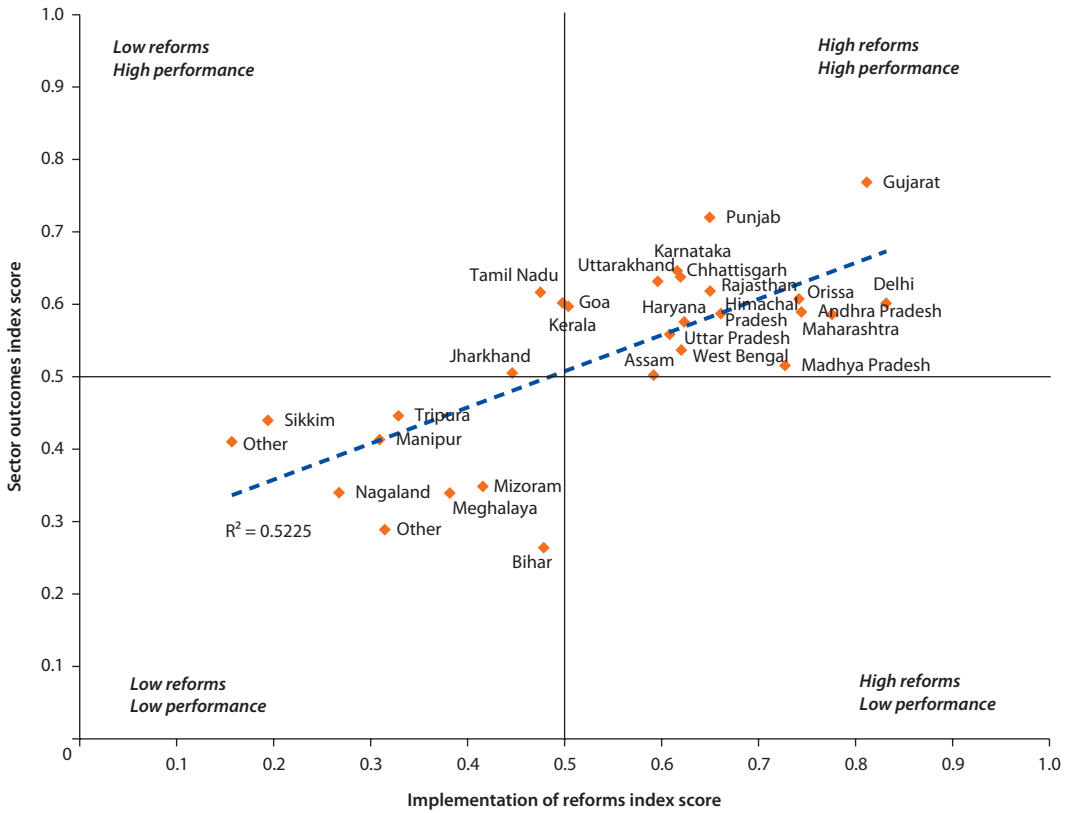
exchequer (of state government subsidies), as well as by increases in access. Fewer states made progress in harnessing their renewable energy potential.

By contrast, the average score on the subindex of outcomes of interest to investors and lenders was lowest of all three subindexes at 0.32, driven by several states scoring less than 0.25 and no states scoring above 0.75. States performed best at increasing the sectors’ commercial viability (particularly at introducing equity into utilities’ capital structures, though about a third of states still have little or no equity in their utilities) but generally underperformed in introducing competition into distribution.

Relationship between Implementation of Reforms and Sector Outcomes

Implementation of reforms and achievement of expected outcomes are strongly correlated. The correlation coefficient between the reform implementation index and the outcomes index is 0.71, and it is statistically significant at the 1 percent level. The states congregate either in the “high reforms, high performance” or “low reforms, low performance” quadrants in figure 5.5. With only two exceptions (Jharkhand and Tamil Nadu), states that scored above 0.5 on the outcomes index also scored above 0.5 on the reform implementation index. Jharkhand and Tamil Nadu are slightly on the high-performing side despite being on the margin in reform implementation. Although they scored just below 0.5 overall on the implementation of reforms index, Jharkhand

Figure 5.5 Relationship between Reform Implementation and Outcomes



Source: Deloitte 2013.

achieved a relatively high score (0.74) in the subindex of quality and affordability as did Tamil Nadu in the subindexes of quality and affordability (0.76) and access (0.77).

Note

1. Ideally, the implementation of reforms index would also cover energy efficiency. But objective indicators to measure initiatives in this area were not available across all states, so it is not included in the index.

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The Role of Governance and Institutional Factors

The Electricity Act of 2003 (EA 2003, or EA) mandated unbundling and corporatizing the state electricity boards (SEBs), along with establishing independent regulators at the central and state levels and the Appellate Tribunal (ApTel), all for creating a more accountable and commercial performance culture. It was considered that much of the poor performance of utilities reflected internal and external shortfalls in governance. A particular motivation was the need to keep the state government at arm's length from utilities and regulators alike.

State power sector utilities rarely face the accountability pressures that commercial enterprises do from equity owners, or even creditors. Most are publicly owned, with ownership vested in the state government, and unlisted, so not subject to the discipline of stock markets. At the same time, as utilities, their operational performance is shaped by the framework established by the regulator (such as tariffs and performance standards). Public ownership, moreover, means that the interests of owners may differ from the objectives of maximizing profits or shareholder value that are usually associated with a private corporation. The incentives and responses, too, of publicly owned firms to regulatory rules differ from those of privately owned utilities.

The fundamental issue of the extent to which the regulator can influence the actions of a utility that is owned by the state remains unresolved. Regulators can only infrequently apply sanctions to utilities because they generally have less political weight than utilities. In fact, "unless the internal governance of the utility focuses on performance (via pressure from the Board of Directors)," the regulator is unlikely to be able to improve performance (Berg 2013, 12). Thus sound regulatory and corporate governance are reinforcing elements in utilities' operating environment.

Unbundling the SEBs has progressed quite well on paper, but full separation with functional independence of the unbundled entities has generally not occurred. Also, boards remain state dominated, lack sufficient decision-making authority, and are rarely evaluated. The few utilities that have developed

information-driven processes and sound mechanisms for performance management and that make their accounts and audits publicly available tend to be the top financial performers with high operational efficiency, pointing to the potential for sound governance to lead to improved performance.

On regulatory governance, state electricity regulatory commissions (SERCs) have struggled to achieve true autonomy from state governments, partly because of relationships built into the EA. Many SERCs appear to fall short on the resources needed to carry out their functions—most notably, professional staff and appropriate information technology (IT) systems. And despite some innovations, most SERCs have yet to implement adequate transparency measures or create frameworks for meaningful public input to the regulatory process. Finally, perhaps most important, there is no clear accountability mechanism to govern the SERCs themselves.

Additional institutional pressures on utility performance come from the requirements of centrally designed and funded government initiatives that must be executed by the distribution utilities. Such measures often impose collateral costs on utilities that are not always obvious up front. Beyond that, deficiencies in implementation often mean that the anticipated returns do not fully materialize, a particularly relevant factor for the two large centrally driven programs in power distribution—the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and the Restructured Accelerated Power Development and Reform Programme (R-APDRP).

Vertical Restructuring: Unbundling State Electricity Boards

Unbundling the SEBs to create distinct companies with independent accounts and staff was anticipated to lead to greater transparency in operational performance of each element in the service delivery chain, creating incentives for each such element to achieve a profit (Tongia 2003). Corporatization itself was intended to create an arm's-length relationship between the state government and the utility, and thus create space for the utility to operate along commercial lines.

Yet unbundled utilities often remain part of a single holding company. And whether such unbundled companies are actually run as distinct entities is unclear, as the chairman of the holding-company board and of the successor-company boards is frequently the same person and, indeed, board membership often partly or completely overlaps. This structure undermines the main reason for unbundling—and muddies lines of accountability. Only half the states that have unbundled their SEBs have actually finalized staff transfer and created separate cadres for each of the unbundled entities. In addition, inherited staff and human resources policies that require staff to be absorbed by the successor companies restrict the successors' freedom to manage themselves as commercial entities.

In short it appears that utilities in many unbundled states still do not function independently. Some practices retained include centralized cash flow, lack of

autonomous cash management, lack of independence in financing decisions, and absence of independent power procurement.

Unbundling is thus perhaps better thought of as a process along a continuum rather than a binary state of “on” or “off.” Utilities may be separate entities legally but still make operational decisions (procurement, human resources, IT, regulatory responses) together. They may receive common direction from a holding company. Or they may make financial decisions as a single entity. The closer a utility is to having financial and operational independence the more likely it is that the impacts expected from unbundling—accountability, transparency, and stronger performance—will be observed. This may explain why, in a simple categorization of unbundling, unbundled utilities represent some of India’s worst performers—and some of the best.

Corporate Governance

Corporate governance includes elements of external and internal accountability.¹ For state-owned corporatized enterprises, the role of the board is delicate. As the owner’s agent it monitors management but it also has a fiduciary duty to insulate management from political pressures and ensure that business decisions are taken on their merits.

State-owned corporatized power utilities have to comply with the Companies Act of 1956.² The Guidelines on Corporate Governance issued by the Department of Public Enterprises (DPE), which apply to central public sector enterprises, go well beyond the Companies Act. They are not mandatory for utilities that are owned by state governments, but since they apply to government-owned companies (albeit central rather than state), they are used as the benchmark for recommended practices in this report. Box 6.1 lists key corporate governance good practices relevant for state utilities.

The history of state control of the SEBs means that the autonomy of the board and its ability to operate without government interference are particularly important for corporatized state power utilities. However, state governments often exert informal influence over utility decisions and, in many cases, there are far more government directors on utility boards than recommended—and thus necessarily fewer than recommended independent directors.

The regulator is the other major external entity holding the utility accountable for performance. This relationship, too, must be managed appropriately, including addressing the legitimate interest of the public in key utility information that should be disclosed, such as basic company data, organization charts, company rules, budget allocations, and accounts.

The boards of directors have two major roles in terms of internal accountability: setting company strategies and policies, and monitoring management performance. To improve performance, the board needs to be able to hold management accountable. For a start, it needs information systems that generate the data to monitor management in real time and allow it to create incentives for improving performance. As managerial accountability for performance increases,

Box 6.1 Good Practices in Corporate Governance for State Utilities

Companies Act of 1956 (Mandatory)

- The board needs at least three members.
- The audit committee needs at least three members, two-thirds of whom must be non-executive.
- There needs to be a minimum frequency of meetings.

Department of Public Enterprises Guidelines (Recommended)

Board Composition:

- Executive or “full-time” directors should constitute 50 percent or less of the board.
- There should be two or fewer government representatives (which should constitute a maximum of one-sixth of the board).
- Independent directors should constitute a third or more of the board (if the chairman is not an executive director); otherwise 50 percent or more.

Board Functioning:

- The board should meet at least four times a year, with a maximum of three months between meetings.
- It should conduct peer evaluations of non-executive board members.

Audit Committee:

- An audit committee is required.
- It should have three or more members, two-thirds of which, including the chairman, must be independent directors.
- Members should be able to understand basic financial statements.

Government-Board Relationship:

- There should be clarity about where the board has decision-making powers and where the board must seek government approval.
-

utilities can be expected to reengineer business processes to improve management control and customer service.

Findings

The following review of corporate governance is based on basic governance data for 2010 from 69 of the 89 utilities in 19 states that the Power Finance Corporation covered in its report for 2008/09 through 2010/11 (PFC 2012).³ Detailed qualitative information and data were obtained from management of 21 of these utilities, in 14 states, as well as from the regulators and government departments in those states.⁴

The data show that boards continue to be state dominated and lack sufficient decision-making authority. Constraining the autonomy of the chairman and managing director (CMD) and of the board is the state government’s

involvement in key recruitment, personnel, procurement, and enforcement decisions, underlining the fact that the desired arm's-length relationship between the utility and government has not been achieved. In addition, CMD tenures are often too short for them to see through the execution of their agendas. Finally, board member training and peer evaluation are notably absent. Professionalizing and empowering boards is a key requirement going forward.

While most utilities largely comply with the minimal corporate governance requirements of the Companies Act, far fewer follow the DPE guidelines that can be considered recommended practice for utilities (and are required for centrally owned utilities and companies).⁵ Few utilities have put the necessary processes in place to support their governance structures. Only about a third of utilities have an advanced management information system, and no utility has a corporate performance monitoring system, suggesting that organizational transformation is still a work in progress.

The indicators collected for this review can be aggregated into two corporate governance indexes:

- A “basic” index with coverage of 67 of the 69 utilities that indicates the degree to which utilities have adopted eight standard corporate governance good practices (table 6.1).
- A “detailed” index across 18 indicators including the eight standard practices and covering internal processes and relationships with the government.⁶ The detailed index is available only for the 21 utilities for which detailed qualitative information was obtained.

Index scores are calculated as the share of total indicators for which the utility complies with the recommended practice.

Table 6.1 The Basic Corporate Governance Index

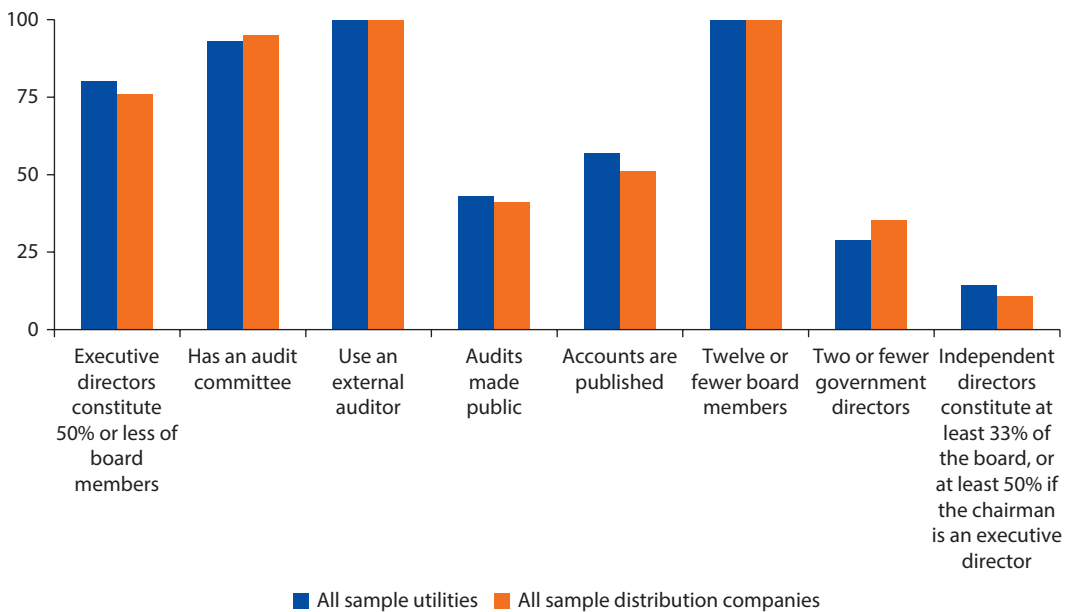
<i>Indicator</i>	<i>Requirement for a score of 1</i>	<i>Share of sample meeting this (%)</i>
<i>External accountability</i>		
Independent directors	Constitute at least 33% of the board, or at least 50% if the chairman is an executive director	15
Government directors	Two or fewer	28
Audit made public	Yes	45
Publish accounts	Yes	58
Use an external auditor	Yes	100
<i>Internal accountability</i>		
Executive directors	Constitute 50% or less of board members	81
Board size	Twelve or fewer	97
Has an audit committee	Yes	93
Overall (basic index) compliance: 61%		

Source: Pargal and Mayer 2013.

The 67 utilities covered by the basic index score an average of 61 percent on compliance with recommended practices. The lowest compliance rate is 38 percent (Tripura’s corporation, Uttar Pradesh’s UPJVNL generation company, Tamil Nadu’s SEB, and Karnataka’s Mangalore Electricity Supply Company), while full compliance is achieved by Assam’s distribution company (discom) and Gujarat’s holding company. Twelve utilities, about 18 percent of the sample, comply with all but one of the indicators (all have more than two government directors). All utilities use an external auditor and almost all have boards with 12 or fewer members. But compliance with measures of external accountability—the number of government directors and share of board that consists of independent directors—is relatively low. The performance of distribution utilities is similar to that of the sample as a whole, suggesting that all power utilities work within the same corporate governance compact (figure 6.1).

Among the 21 utilities with detailed information, 5 stand out as following at least two-thirds of recommended corporate governance practices: Gujarat’s discom (Dakshin Gujarat Vij Company, or DGVCL) and holding company, West Bengal’s discom and transmission company, and Tata Power in Delhi (table 6.2). These utilities are also some of the stronger financial or operational performers, sometimes both. DGVCL and Tata Power are among the five discoms with the lowest aggregate technical and commercial losses, and DGVCL, Tata Power, and West Bengal’s discom are among the six discoms with the highest profits per unit of energy sold. This connection between strong corporate governance and

Figure 6.1 Basic Index: Share of Utilities in Compliance with Key Good Practices
Percent



Source: Pargal and Mayer 2013.

Table 6.2 Characteristics of Top Five Utilities Covered in the Detailed Index

		Gujarat— DGVCL	Gujarat— GUVNL	West Bengal— WBSEDCL	West Bengal— WBSETCL	Delhi— TP-DDL
		Discom	Holding company	Discom	Transmission company	Discom
Board- management relationship	Share of board that is executive directors (%)	14	33	50	50	9
	Audit committee	Y	Y	Y	Y	Y
	Other committees	Y	Y	Y	Y	Y
	Independent head of audit committee	Y	N	Y	Y	N
	Audits on time	Y	Y	Y	Y	Y
Public accountability	Audits made public	Y	Y	Y	Y	N
	Accounts made public	Y	Y	Y	Y	N
Board effectiveness	Number of directors	7	6	12	8	11
	Average chairman and managing director tenure (years)	2.3	2.8	4.0	3.0	5.0
External accountability	Number of government directors	3	2	2	2	5
	Share of board that is independent directors (%)	43	33	33	25	18
	Government influences routine matters	N	N	N	N	N
	Government influences recruitment	N	N	N	N	N
	Uses an external auditor	Y	Y	Y	Y	Y
Management practices	Enterprise resource planning or management information system	Y	Y	N	N	Y
	Performance-linked incentives	Y	Y	N	N	Y
	Employee training policy	Y	Y	Y	Y	Y
	Merit-based promotions	Y	Y	Y	Y	Y

Source: Pargal and Mayer 2013.

Note: DGVCL = Dakshin Gujarat Vij Company Ltd.; discom = distribution company; GUVNL = Gujarat Urja Vikas Nigam Ltd.; WBSEDCL = West Bengal State Electricity Distribution Company Ltd.; WBSETCL = West Bengal State Electricity Transmission Company Ltd.; TP-DDL = Tata Power Delhi Distribution Ltd.

performance could be due to the positive impact of strong governance practices on profits and efficiency, or because more profitable firms tend to follow better corporate governance practices.⁷ Good practices and lessons from utilities in West Bengal and Gujarat (boxes 6.2 and 6.3) are described below.

On the “detailed” index, the 21 utilities covered follow recommended practices on average for only 46 percent of the indicators. By contrast, these utilities complied with on average 67 percent of the indicators in the basic index.

Box 6.2 Corporate Governance in West Bengal

By 2002, years of inefficiencies in transmission and distribution had led to annual losses of around \$300 million in West Bengal's power sector. The state government decided to restructure the sector and adopt measures to enhance accountability, anticipating that this would lead to improved performance and a lower burden on the exchequer. By 2007 it had unbundled its state electricity board (SEB) into separate generation, transmission, and distribution utilities (though hydropower generation remained with the distribution company).

As in many states the government took on SEB liabilities in the unbundling process. But, unique to West Bengal, it mandated utility compliance with India's corporate governance requirements for listed companies (Clause 49 of the Securities and Exchange Board of India's Listing Agreement). The new utilities were to be run by their boards without state interference provided that they did not request state budgetary support. For example, recruitment and procurement decisions would not require state government signoff. This is still the agreement today. With state governments again faced with bailing out utilities, there is a valuable opportunity to follow West Bengal's model.

West Bengal's agreements and understandings established utilities with robust governance practices and gave them the space needed to establish core operating principles under the guidance of strong independent directors brought onto the utility boards at inception. Once the utilities were financially and operationally efficient (including computerized billing, 100 percent feeder metering, strict monitoring and vigilance to prevent theft, and near 100 percent consumer metering), the operating principles became firmly entrenched and have remained largely undisturbed, despite a major change in the state's political governance.

The articles of association of the state's utilities mirror these agreements. They set out a well-defined process for director selection and removal, give clear direction on the board's powers, establish a fixed tenure (minimum of three years) for directors, and limit the board to 12 members. A clear director selection process has helped prevent the board being stacked with political appointees who might have lacked business acumen and the necessary technical background (though this process could be strengthened by defining selection criteria). Specified tenures provide stability and certainty, ensuring that directors will be present for long enough to have an impact. And restrictions on board size protect against a lack of focus.

West Bengal also capitalized on its government officers' knowledge of global best practices in power reform. While it was obvious that "one size does not fit all," reformers were able to present successful examples of new operational models to advocate for change with employee organizations and political executives. This is considered to have enabled reforms such as establishing objective employee performance assessments and performance-linked promotions. Employee resistance was also low because a long hiring freeze meant that the reorganization would lead to better prospects for career growth. In addition, this allowed the utilities to reskill fairly painlessly.

Importantly, West Bengal's state electricity regulatory commission is one of the few to consistently raise tariffs to cover the cost of supply, increasing tariffs each year from 2007/08 to 2010/11. Tariff increases came to a halt in 2011/12 under a new state government but resumed

box continues next page

Box 6.2 Corporate Governance in West Bengal *(continued)*

recently, reportedly in part because the state utilities made a compelling case to the new government that its constituents were willing to pay more for the consistent and reliable power that higher tariffs enable.

Source: Pargal and Mayer 2013.

Box 6.3 Organizational Transformation and a Turnaround in Performance in Gujarat

In 2000 the Gujarat Electricity Board (GEB) was one of India's worst-performing power utilities—a drag on the government's finances and the state's development. A decade later, the Gujarat Urja Vikas Nigam (GUVNL) group, comprising seven interlocked companies, is a model public utility, winning innovation and customer service awards. It is efficient, agile, and profitable.

State leaders gave full support to the turnaround. While power purchase remained centralized even after the GEB was unbundled, authority and decision making were decentralized to constituent companies, each with its own corporate office and a professional board. Politicians were replaced by bureaucrats and professionals on the board of GUVNL, the holding company, as well as the boards of its constituent units, while the very best generalist administrators were appointed to the top management of the unbundled utilities. Strong political backing was given to the distribution company (discom) staff, including in matters such as halting power theft by the politically connected.

A multipronged change management strategy was put in place. It involved a purposeful campaign of information, education, and communication, using dialogue to jointly develop solutions to issues raised by staff, incentivizing improved housekeeping practices to increase revenues and cut costs, and implementing initiatives to improve utility finances by cutting transmission and distribution losses, flab in the organization, and theft. The government neutralized employee apprehensions by signing a tripartite agreement with GEB management and employee unions that working conditions would be no worse after unbundling, no jobs would be shed, nor any employee relocated without consent. Starting the new entities off with a clean balance sheet made financial sustainability of the new structure achievable. The work culture was transformed by investing heavily in training and capacity building of all staff, from the chairman and managing director to the lineman.

The management of the "GUVNL family" also strengthened driving forces for change: for example, e-Urja—an enterprise resource planning platform—became instrumental in developing a strong information and communications technology culture that has empowered staff to develop homegrown solutions to their problems. Decentralized decision making empowered even junior field staff. Competition among discoms contributed to galvanizing employees around corporate goals. And a culture of performance management around key performance indicators further enhanced staff participation. For instance, to curb farmers stealing power from single-phase supply by using phase-splitting capacitors, discom engineers designed special transformers that trip whenever the load exceeds a given limit.

Source: Shah and others 2012.

Link between Corporate Governance and Utility Performance

For the utilities in the sample, the basic corporate governance index is not correlated with measures of performance—profits per kilowatt-hour (kWh) with and without subsidies. But the detailed index is strongly positively correlated (significant at the 1 percent level) with profits per kWh without subsidies for all utilities and for discoms only (table 6.3). This correlation only covers 20 utilities, making the significance of these results all the more striking.

The observed correlation is consistent with the idea that the more demanding implementation-related aspects of corporate governance captured in the detailed index strongly affect company performance. The basic index focuses on board size and structure, which may be somewhat superficial—the real impact on performance depends on more meaningful attributes of organization management. Higher-quality boards are likely to induce internal organizational and process changes in response to their demands for better information and their interest in holding management accountable for delivering results. This reasoning is consistent with the need for corporate governance practices that go beyond simply ticking boxes and for boards to actually be strategic and demanding in their approach to implementing their mandates.

Another explanation consistent with the observed lack of correlation between the basic index and utility profits comes from the evidence—much of it qualitative—that the state government remains a big presence in these utilities and has a say in critical decisions, despite the formal creation of a board to insulate management from state interference. This means the state as owner can undermine the board, so the fact that the board structure and size are consistent with recommended practices or statutory requirements would not necessarily be associated with better performance.

The results of an ordinary least-squares cross-section regression of 2010 utility financial performance (measured by per unit profits without subsidies) on state controls (including measures of regulatory governance), utility controls,

Table 6.3 Correlation between Corporate Governance Variables and Performance Measures

<i>Index</i>	<i>Performance variables (2010)</i>			<i>Performance variables (2011)</i>		
	<i>Profit per unit (without subsidies)</i>	<i>Profit per unit (without subsidies)— discoms only</i>	<i>Profit per unit (with subsidies)— discoms only</i>	<i>Profit per unit (without subsidies)</i>	<i>Profit per unit (without subsidies)— discoms only</i>	<i>Profit per unit (with subsidies)— discoms only</i>
Basic corporate governance index	0.039	0.059	−0.090	0.039	−0.068	0.052
Detailed corporate governance index	0.621***	0.791***	0.612**	0.621***	0.751***	0.507*

Source: Pargal and Mayer 2013.

Note: discom = distribution company.

Significance level: * = 10 percent, ** = 5 percent, *** = 1 percent.

and corporate governance indicators are consistent with these findings (see appendix N). While the basic index is not significantly related to utility performance, the share of the board that is executive directors is significantly negatively associated with performance and the share of the board that is independent directors is positively associated with performance.⁸

Overall, the analysis undertaken for this review indicates that going beyond the Companies Act requirements and implementing the DPE-recommended practices (and even going beyond those to effect organizational transformation) are associated with significantly higher profits per unit, indicating a potential win-win.

Regulatory Governance

Establishing state electricity regulators under the Electricity Regulatory Commission Act of 1998, and, subsequently, the EA 2003 was intended to reduce government control over the power sector and delink it from electoral politics. The EA 2003 aimed to create an independent, unbiased, and transparent governance framework that balanced consumer and investor interests, specifically by removing regulation and tariff determination from the purview of the government.⁹

The SERCs are mandated to play multiple roles. They are expected to prevent state intervention in the sector and protect the interests of different stakeholders by regulating the operations of power utilities and the tariff chargeable to consumers (Prayas Energy Group 2003). Key responsibilities include issuing licenses for distribution and intra-state transmission; ensuring nondiscriminatory open access to both the transmission and distribution systems to promote competition and support the development of a multibuyer market and power trading; regulating and rationalizing tariffs to cover costs; implementing multiyear tariff frameworks to reduce uncertainty and encourage investment in the sector; establishing and monitoring standards for licensee service quality and reliability; and safeguarding consumer interests, such as by setting up mechanisms to redress grievances. In addition, the SERCs are tasked with drafting, notifying, and implementing additional regulations to enact the EA mandates.

The ability of the SERCs to carry out their mandates depends on their technical, financial, and human resources; their competence; their autonomy in decision making (including insulation from political pressures); and their accountability—all falling under the rubric of institutional design (ID).

Analyzing Performance of SERCs

To efficiently organize the information available under different heads and analyze the performance of the SERCs, simple indexes (unweighted averages) have been created to measure how each SERC implemented key regulatory mandates and their rating on the main pillars of ID (table 6.4). All SERCs other than those in three small states, where data are very spotty, are included.

Table 6.4 Indexes of Implementation of Key Regulatory Mandates and Institutional Design

<i>Index</i>	<i>Component</i>	<i>Requirement for a score of 1^a</i>	<i>Average score of all SERCs^b (%)</i>
<i>SERC implementation of key regulatory mandates (average score is 74%)</i>			
Tariffs	<ul style="list-style-type: none"> • From 2007/08 to 2009/10, the number of years the SERC published a tariff order more than 120 days after receiving the utilities' annual revenue requirement filings • Share of years in existence (or years since 2000/01, whichever is less) in which the SERC published a tariff order • Does the 2010 average billed tariff equal or exceed operating cost recovery?^c • Has a cost of supply study been conducted? • Has a multiyear tariff order been issued? 	<ul style="list-style-type: none"> Zero or one year More than 66% Yes Yes Yes 	47
Protection of consumer rights	<ul style="list-style-type: none"> • Does the SERC have an ombudsman? • Has the state advisory committee been established? • Have Guidelines on Consumer Grievance Redressal Forum been notified? 	<ul style="list-style-type: none"> Yes (1 point per item) 	99
Standards of performance	<ul style="list-style-type: none"> • Has the SERC issued regulations on standards of performance? • Are penalties for noncompliance clearly defined? • Does the SERC monitor compliance with standards? • Does the SERC issue penalties for noncompliance? 	<ul style="list-style-type: none"> Yes (1 point per item) 	70
Other regulations	Has the SERC issued regulations on: <ul style="list-style-type: none"> – Supply code? – Trading? – Metering? – Multiyear tariff? – Intra-state availability-based tariff? 	<ul style="list-style-type: none"> Yes (1 point per item) 	71
Open access	<ul style="list-style-type: none"> • Have open access regulations been issued? • Has an open access surcharge been determined? • Has an open access wheeling charge been determined? • Has an open access transmission charge been determined? • Have open access applications been received? 	<ul style="list-style-type: none"> Yes Yes Yes Yes One or more applications 	82
Renewable energy and energy efficiency	<ul style="list-style-type: none"> • Have renewable energy regulations been notified? • Are renewable purchase obligations technology-specific? • Does the SERC monitor compliance with renewable purchase obligations? • Does the SERC issue penalties for noncompliance? • Has a feed-in tariff been determined? • Does the SERC have measures or incentives to promote consumer demand-side management? • Does the SERC have a provision for time-of-day tariff? • Have regulations on energy efficiency and demand-side management been issued? • Have time-of-day metering regulations been issued? 	<ul style="list-style-type: none"> Yes (1 point per item) 	75

table continues next page

Table 6.4 Indexes of Implementation of Key Regulatory Mandates and Institutional Design (continued)

<i>Index</i>	<i>Component</i>	<i>Requirement for a score of 1^a</i>	<i>Average score of all SERCs^b (%)</i>
<i>SERC institutional design (average score is 48%)</i>			
Autonomy	• What was the average chairman tenure over the last 10 years (or since the SERC was created, whichever is shorter)?	Five or more years	42
	• Is the budget from own revenues or a mix of own revenues and state grants?	Yes	
Capacity	• Is there a Regulatory Information Management System?	Yes	28
	• Number of professional staff	Fifteen or more (per Forum of Regulators recommendation)	
Transparency	• Are regulatory decisions online?	Yes (1 point per item)	75
	• Are public hearings held before the tariff order?		
	• Is the updated hearing schedule online?		
	• Are annual reports available on the website?		
	• Are annual reports available in the local language?		
	• Is the Constitution of the state advisory committee online?		
	• Are the minutes of the state advisory committee online?		

Source: Pargal and Mayer 2013.

Note: SERC = state electricity regulatory commission.

a. The benchmarks are taken from legislation or recommended best practices, except standards for publishing tariff orders annually and on time, which are as specified in the table.

b. The exclusion of three small states may skew averages upward, as these states had generally not achieved the benchmarks considered in this report for which data were available.

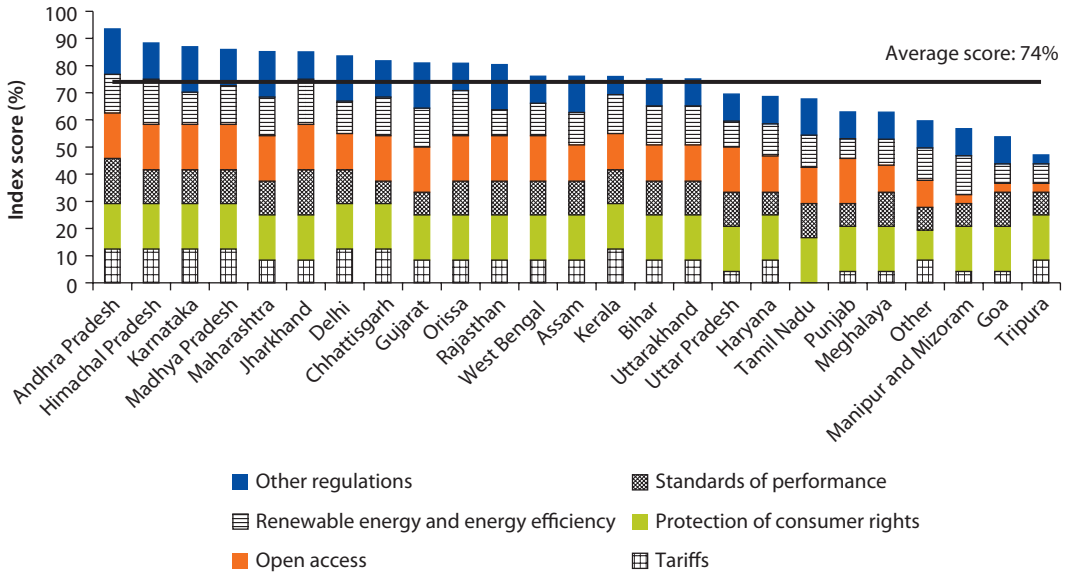
c. Operating cost recovery is defined as the tariff level that covers (equals) average operating cost plus a premium to account for “normal” distribution losses, which are set at 10 percent for India for this analysis.

The “overall” indexes are simple averages of the subindexes. Thus the ID index averages scores on the subindexes for regulator autonomy, transparency, and capacity. (In the absence of quantitative benchmarks, an index has not been developed to measure regulator accountability.) The subindexes are calculated as the share of relevant criteria in each subindex category with which each state regulator complies. The implementation of key regulatory mandates (IM) index averages the scores on the subindexes for tariffs, protection of consumers, standards of performance, open access, renewable energy, and notification of other regulations.¹⁰ The two indexes are significantly (at 1 percent) positively related with a correlation of 0.59, suggesting that implementation of mandates moves in line with desirable ID.

The SERCs receive an average score of only 48 percent on the ID index but an average of 74 percent on the IM index, on which Andhra Pradesh, Himachal Pradesh, and Karnataka are the highest-ranking SERCs. Most SERCs score close to or above the average on the IM index (figure 6.2).

While progress has been significant, most SERCs have not yet fully implemented the EA mandates. For instance, average billed tariffs cover average cost

Figure 6.2 Implementation of Key Regulatory Mandates Index Scores



Source: Pargal and Mayer 2013.

in most states, but increases in tariffs have generally not kept pace with cost increases and very few states issue multiyear tariffs (despite issuing multiyear tariff regulations). Only five SERCs have ever conducted a cost of supply study. Standards of performance have been notified by almost all SERCs, but only 75 percent monitor compliance, and only two have ever imposed a penalty for default. Most SERCs are nominally complying with mandates to promote consumer empowerment and increase transparency to the public, but they need to ensure that consumers are given opportunities to engage in the regulatory process and that high-quality information is available to the public.

Going beyond the EA, 10 SERCs have reported establishing consumer advocacy cells—a bright spot. (Box 6.4 highlights other good practices.) Finally, though many SERCs have notified most of the key regulations necessary to enact the EA mandates, quite a few have yet to actually implement these regulations. For example, only half the states have even received an open access application, and only 10 have actually implemented open access for an applicant. On renewable energy and energy efficiency, most states have notified basic regulations for renewable purchase obligations, but only 18 monitor compliance, and only 4 have issued penalties for noncompliance. Significantly fewer states have passed demand-side management, feed-in tariff, or time-of-day regulations.

The highest-ranking SERCs on the ID index are Gujarat, Orissa, and Delhi, with most SERCs scoring below the average (figure 6.3). The background analysis presents four reasons for this (Pargal and Mayer 2013). First, the SERCs have struggled to achieve true autonomy from state governments, partly because of relationships built into the EA. Second, many SERCs lack the resources that

Box 6.4 Involving Consumers as Stakeholders: Selected State Electricity Regulatory Commission Experiences

The state electricity regulatory commissions (SERCs) of Delhi (DERC) and Maharashtra (MERC) stand out as having developed innovative mechanisms to ensure public opinion is taken into account in regulatory proceedings. Madhya Pradesh's (MPERC) is notable for raising consumer awareness of standards of performance.

The DERC began conducting consumer surveys in 2007, and Delhi remains the only state in which surveys are carried out regularly, with the results used to measure licensee performance. The survey asks 10,000–15,000 domestic consumers about their preferences along seven macro parameters (such as supply continuity and quality); their satisfaction with their distribution companies (discoms) along several micro parameters; and their ranking of the importance of each parameter. The DERC publishes the survey findings in its annual reports along with the scores of the three discoms and the best- and worst-performing areas for each discom.

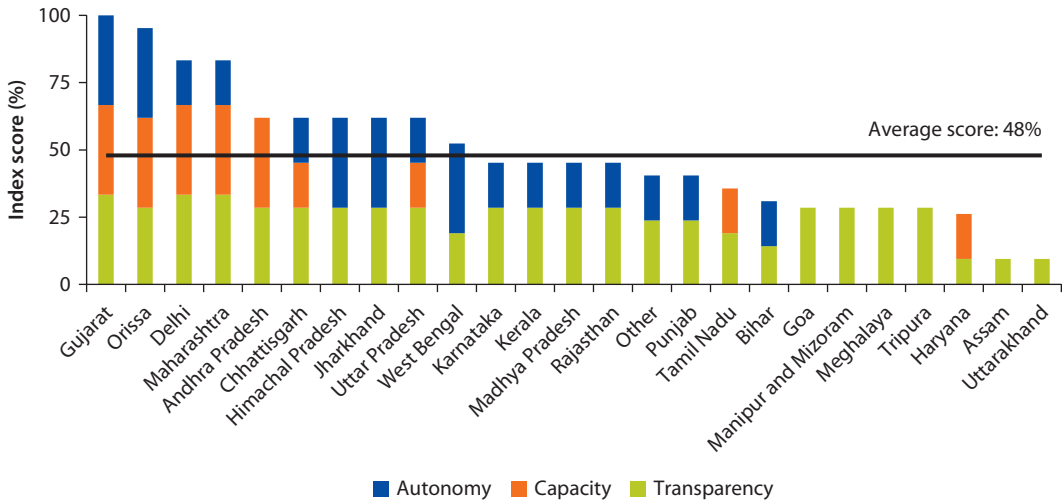
The MERC is the first and still only SERC to form a panel of authorized consumer representatives to represent the interests of consumers in SERC proceedings. The relevant regulation states that the representatives should also recommend capacity building for consumer groups and take steps to improve the efficacy of the SERC's regulatory processes (though it does not say how it expects the representatives to do this). From time to time, the MERC may also direct the representatives to educate consumers on demand-side management and their rights to service, provide advice to the SERC on safeguarding consumers' interests in SERC orders and regulations, assist the SERC in improving the efficacy of its consumer grievance redressal mechanisms, and bring to the SERC's attention any noncompliance with its orders and regulations. The panel comprises a mix of individuals and registered organizations working on consumer grievances, both selected through a process specified in the MERC regulations.

The MPERC is one of the few SERCs that has taken steps to increase consumer awareness of standards of performance to mitigate the significant challenge that lack of awareness poses to successful implementation of the regulations. It monitors utilities' compliance with the standards and publishes an annual compliance report in newspapers, in English and Hindi, and on its website. It has also directed licensees to publish the standards on noticeboards in key sub-division offices for consumers visiting the offices.

Source: Pargal and Mayer 2013.

might assist in performing their functions—most notably, adequate numbers of professional staff and appropriate IT systems. Third, most SERCs have yet to implement adequate transparency measures and create frameworks for meaningful public input on the regulatory process.

And fourth, the lack of a clear accountability mechanism to govern the SERCs themselves is clear from the absence of an appropriate measure of such accountability. All SERCs are technically accountable to the state legislature, as the SERC submits rules and regulations to the legislature before issuance. The SERCs also file their audited accounts and annual reports with the legislature.

Figure 6.3 Institutional Design Index Scores

Source: Pargal and Mayer 2013.

But in practice, the state legislatures ask few questions about rules and regulations, and there have been few instances noted of proactivity from the legislature. Even SERC budgets are usually passed with little debate.

An additional accountability channel is the ApTel, established under the EA 2003 to hear appeals by those aggrieved by SERC orders, subjecting the SERCs to judicial scrutiny. At the request of the Ministry of Power, in 2011 the ApTel issued directions to all SERCs to revise tariffs periodically, by *suo motu*¹¹ action, if necessary, in the interest of improving the financial health and viability of the electricity sector in general and distribution utilities in particular (Appellate Tribunal for Electricity 2011). But since the ApTel is not mandated to routinely monitor or review SERC performance, its mandate would need to be modified for it to function as a proper accountability mechanism. The consumer protection measures that the SERCs are required to put in place are a further accountability device. Lack of full public transparency and limited follow-through on noncompliance with standards of performance, however, inhibit consumers' ability to meaningfully hold the SERCs accountable. Likely in recognition of this lack of accountability, the Shunglu Committee, set up by the Planning Commission in 2010 to review the financial problems of the SEBs and discoms and to identify steps to improve their performance, recommended instituting SERC performance monitoring (Planning Commission 2011). And in early 2013 the central government initiated discussion on a possible amendment to the EA 2003 to strengthen the accountability framework for the SERCs.

Regulatory Governance and Performance

The correlation between each of the two indexes of regulatory governance and measures of utility financial performance is positive and significantly different

from zero at the 1 percent level, underlining the importance of regulatory governance to utility functioning. This result holds for all utilities in the sample as well as for the subset that is discoms. Utility financial performance is measured by profits per unit without subsidies (for all utilities and for discoms) as well as profits per unit with subsidies for discoms only.¹²

Appendix N shows that in an ordinary least-squares cross-section regression of 2010 utility financial performance on utility controls, state per capita income and each of the regulatory governance indexes separately, the indexes are significantly positively related to utility profits per unit without subsidies. When included in the same regression together, only the ID index is significantly different from zero.

The ID index captures the features of the regulatory framework, such as predictability, and certainty and quality of regulatory decisions that are expected to impact utility strategic and operational choices, while the IM index goes to the heart of how active the regulator has been (and potentially is likely to be). Some areas of regulatory action would likely improve the utility's operational viability (including regular tariff revisions to cover costs), while others may have a negative impact on profits (such as clean energy mandates or open access that would draw away large industrial or commercial consumers) so the net effect of the IM index is not necessarily predictable. This result is robust to the inclusion of corporate governance controls in the regression—that is, the coefficient on the ID index remains positive and significant, while the coefficient on the IM index is positive but not significantly different from zero. Thus, getting the design of regulatory institutions right—especially key attributes such as autonomy, capacity, and transparency measured in the ID index—should be a priority for states.

Effect of Regulatory Decisions on Utilities' Finances

The regulator shapes the environment in which utilities operate, most directly through decisions on the expenses considered appropriate for passing through to consumers through the tariff.

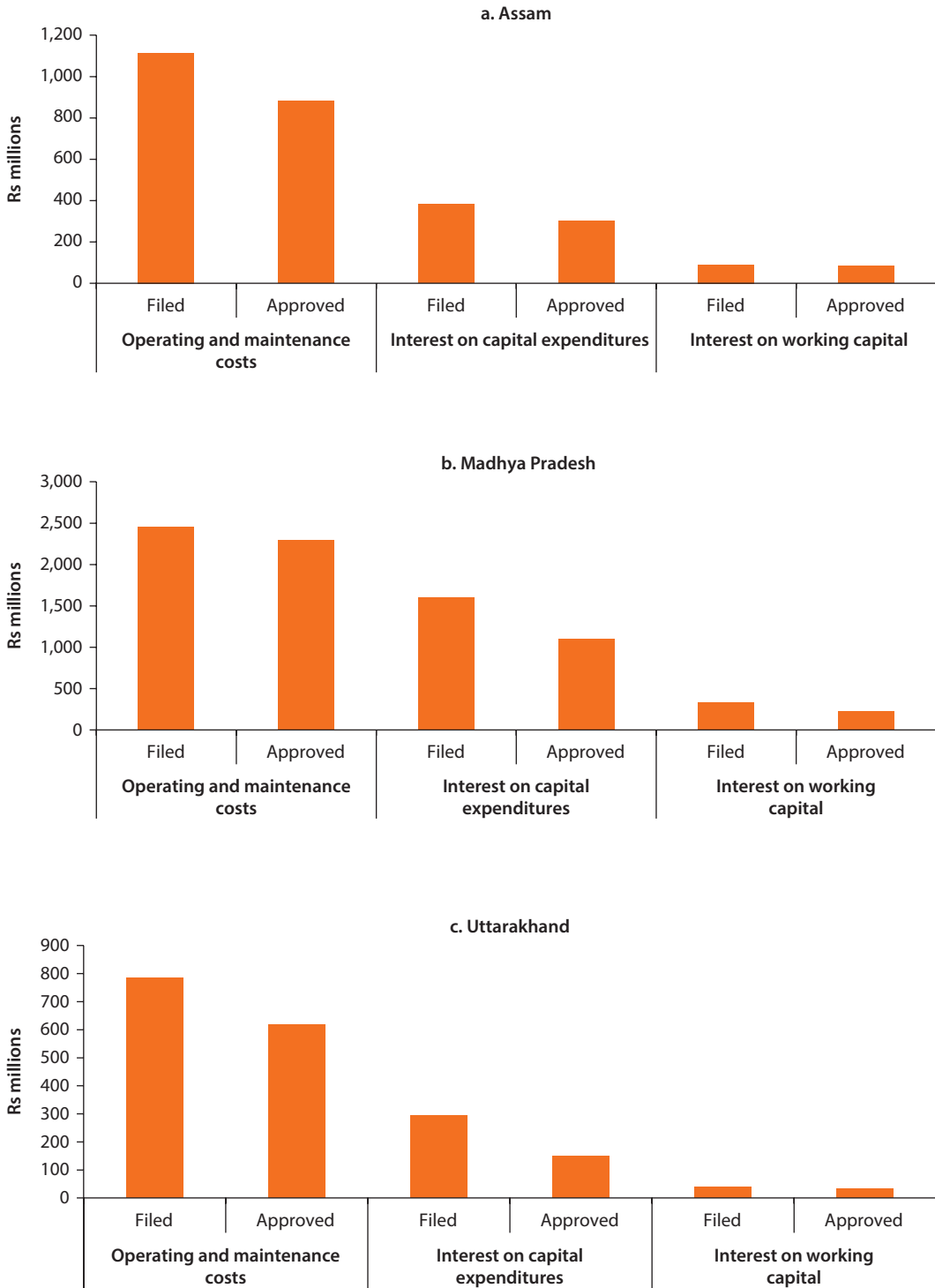
Expense Disallowances

The expenses claimed by utilities often differ widely from those allowed by the SERC. In recent years many regulators have not permitted pass-through to the tariffs of the full cost of power purchased, particularly for the power bought in the short-term market. So discoms have been unable to fully recover their costs—a serious blow, as power purchase accounts for 70–80 percent of discoms' operating costs.¹³ Likewise, the impact of disallowing interest expenses on short-term borrowing hits utility profits. Similar disallowances have been experienced for transmission (figure 6.4).

Disallowance of Return on Equity

The Central Electricity Regulatory Commission has set the return on equity for generation and transmission projects at 15.5 percent, which is expected to be followed by the SERCs while deciding on the tariffs applicable in their states.

Figure 6.4 Transmission Company Costs Filed and Approved, 2010/11



Source: Khurana and Banerjee 2013.

But the SERCs in Bihar, Haryana, and Uttar Pradesh, among others, either do not allow or allow less than the specified annual return on equity to their generation and transmission utilities.

Buildup of “Regulatory Assets.”

To avoid a tariff shock to consumers, at times the SERCs do not increase tariffs during the period in which costs have increased. The shortfall in revenue of the distribution utility is recognized as a regulatory asset to be recovered through future tariff increases. Mounting regulatory assets have increased the discoms' cash-flow problems, jeopardizing routine operations.¹⁴ In Tamil Nadu, Rajasthan, Punjab, Uttar Pradesh, Haryana, Delhi (see appendix J), and West Bengal, utilities have had to borrow heavily to fund the revenue deficit. Although the ApTel has ruled that regulatory assets must be recovered over three years, the sheer size of current regulatory assets means that this would induce a major tariff shock. Recovery has thus been spread over a longer period, with no relief to utility finances. Exacerbating the problem are delays in “truing up,” regulators assigning lower power purchase costs than used by discoms in their projected revenue requirements to keep starting tariffs low, and the interest burden on cash-strapped discoms that have to borrow to purchase power.

Central Mandates

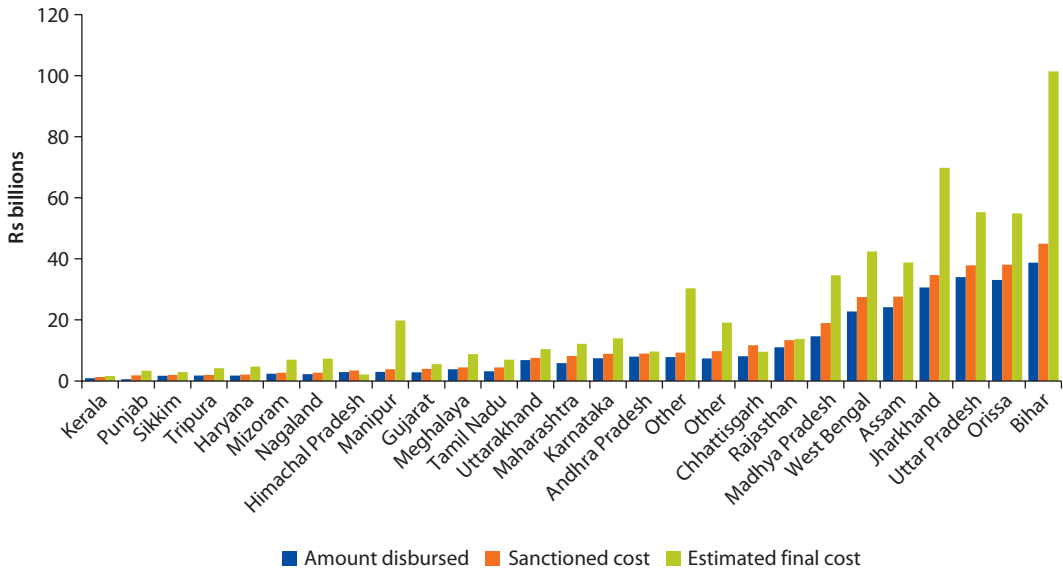
Centrally sponsored programs bring substantial resources to the sector but can also impose costs that are not always anticipated at the design stage. A major source of pressure on distribution utility finances is the mandate to build and “power up” the vast network of lines laid across the country under the central government's flagship access program, RGGVY. Due to low demand (per consumer and overall), high cost of service provision, and low (frequently below-cost) tariffs, this powering-up is nonremunerative.

Where programs have been designed to increase distribution efficiency, weakness in rollout often undermines achieving results. A potentially transformative two-part central program to increase distribution efficiency, the R-APDRP, has not yet realized its potential because of implementation deficiencies.

Finally, since both the RGGVY and R-APDRP are directed at the same utilities, greater coordination between them could generate myriad synergies. For instance, rather than restricting to urban areas the collection of baseline data and use of IT needed for R-APDRP, data collection could be extended to the complete service area of the utilities being supported so that utility performance in rural areas can also be tracked, thus supporting monitoring of RGGVY and putting in place the information base for targeted interventions in the utility service area.

Rajiv Gandhi Grameen Vidyutikaran Yojana

The RGGVY promises a 90 percent subsidy from the Rural Electrification Corporation (REC) for the capital cost of grid extension and for decentralized

Figure 6.5 Amount Disbursed, Sanctioned Cost, and Estimated Final Cost, 2013

Source: Banerjee and others 2013.

Note: \$1 = Rs 45 (average 2005–12).

distributed generation (off-grid) projects. It also promises a 100 percent subsidy from the REC for new connections to households below the poverty line. But the subsidy payments rarely cover even 90 percent of the actual cost, and disbursement is often delayed. As of January 2013 the sanctioned cost by the REC for all RGGVY projects only covered 58 percent of the estimated final cost of Rs 590 billion (\$13 billion), and the government had only disbursed 84 percent of the sanctioned cost (Banerjee and others 2013).¹⁵ This pattern is consistent across states—the disbursed amount is lower than the sanctioned cost (figure 6.5). In all but one state the sanctioned cost is lower than the estimated final cost—and less than 85 percent of the estimated final cost in all but four states. This implies that the state utilities are covering the difference between sanctioned and estimated final cost.

The large differences between the sanctioned cost and the estimated final cost stem from the following:

- *Unrealistically low estimates by states of the funding required to meet RGGVY goals.* The detailed project reports used as the basis for requesting funding often rely on out-of-date surveys and out-of-date lists of households below the poverty line. In addition, as the RGGVY provides free connections only for these households, many states estimate the investment needed for electrification based only on the number of prospective customers below the poverty line, even though households above the line would also likely connect to the new grid. Finally, many states do not involve village *panchayats*

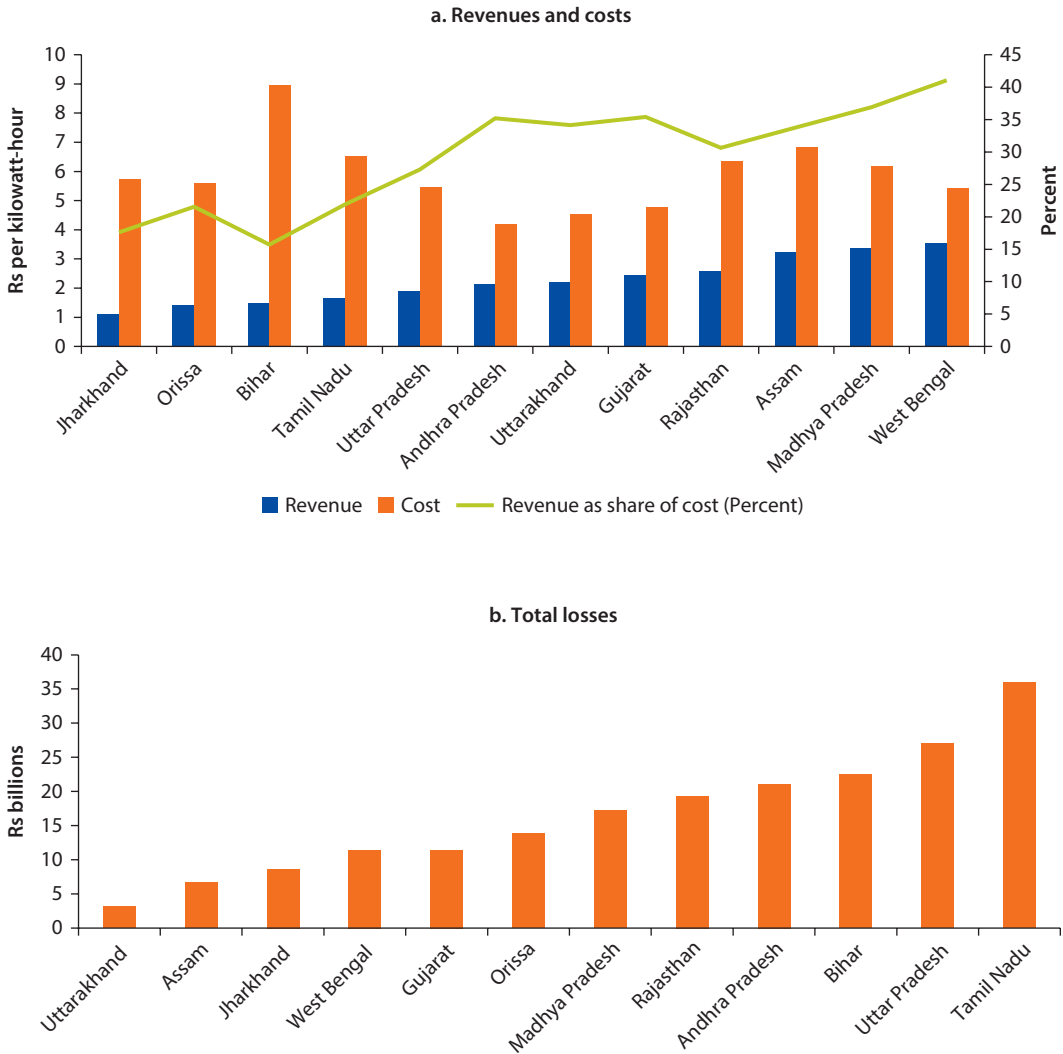
(local governments) in planning, which might permit a more accurate sense of project requirements.

- *Central application of standardized cost norms.* The REC's standardized cost norms do not vary by location (other than to distinguish between the plains and the hill, desert, and tribal areas), cost of living, or other significant factors and are often lower than the costs estimated in the states' detailed project reports. In addition, the REC's village-level norms do not take into account the need for power infrastructure to have adequate capacity to provide electricity for all residents, not just residents below the poverty line. Divergence between the estimates of the detailed project reports and the funding requirements suggested by the cost norms has often meant that the REC approves lower amounts than the states request.
- *Unwieldy revisions process.* While the RGGVY process allows for revisions to sanctioned costs (the original sanctioned costs have been revised up by 29 percent as of January 2013), the process is lengthy and unwieldy, often deterring states from applying for revisions. Changes in overall project costs of up to 20 percent can be approved by the CMD of the REC based on the merits of the case, but larger changes can only be approved by a Ministry of Power committee.
- *The RGGVY's provision of free connections only to households below the poverty line.* In many states households above the poverty line have protested the focus on households below the line. Some have not consented to extending the electricity network across land they own, and some have obtained legal injunctions against projects on grounds of economic discrimination. At a minimum these issues cause long delays in project implementation. To avoid such problems some states (for example, Andhra Pradesh, Jharkhand, Tamil Nadu, and West Bengal) have extended free connections, at their own cost, to households above the poverty line ineligible for RGGVY funds.

Once lines are transferred to utilities, consumers pay the tariffs set by the SERC. But the tariffs paid by customers connected to the grid typically do not cover the full cost of rural supply. Among 12 states studied in detail where a cost-of-supply model was built, the average revenue billed to rural consumers was 16–65 percent of the estimated cost of rural supply (figure 6.6a). Utility executives have indicated that the revenues from supplying new consumers below the poverty line are too low to cover even basic revenue-assurance activities such as billing and revenue collection. Most consumers below the poverty line are thus charged estimated rates, even though they have meters.

In these 12 states the loss to utilities from supplying rural consumers averages around Rs 3.6/kWh (\$0.08), ranging from Rs 1.9 (\$0.04) in West Bengal to Rs 7.5 (\$0.16) in Bihar. The total burden from serving rural consumers in 2010 was just under Rs 200 billion (\$4.4 billion) across the 12 states.¹⁶ Losses ranged

Figure 6.6 Financial Burden of Serving Rural Consumers, 2010



Source: Banerjee and others 2013.
 Note: \$1 = Rs 45.70 in 2010.

from Rs 3.1 billion (\$0.1 billion) in Uttarakhand to Rs 36 billion (\$0.8 billion) in Tamil Nadu (figure 6.6b). These losses placed a very heavy burden on the distribution utilities' finances, one often uncompensated by state government subsidies, as cost of rural service delivery is very hard to estimate.

Restructured Accelerated Power Development and Reform Programme

The centrally sponsored R-APDRP aims to reduce aggregate technical and commercial losses in selected urban areas.¹⁷ It requires participating utilities to demonstrate performance improvements such as sustained loss reduction to

receive financial assistance. As this entails collecting accurate baseline data and measuring performance, reliable and “no manual touch” systems need to be established, and IT needs to be adopted for energy accounting, to ensure data integrity. The R-APDRP provides support for both these aspects, recognizing that they are preconditions for the success of distribution-strengthening projects.

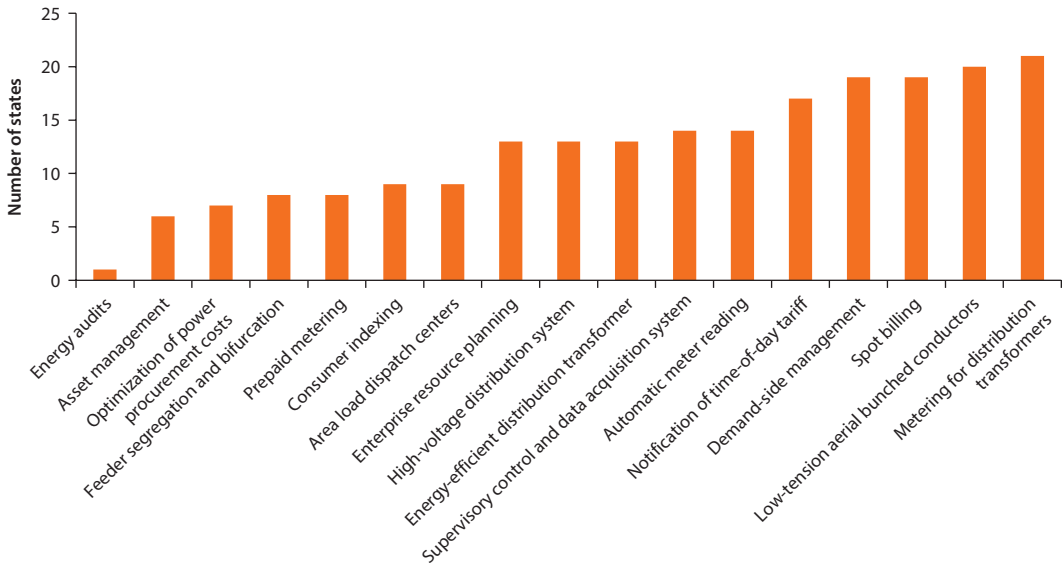
The R-APDRP has two parts. Part A includes support for preparing baseline data for the project area through consumer indexing, Geographic Information System (GIS) mapping, metering of distribution transformers and feeders, automatic data logging for all distribution transformers and feeders, and supervisory control and data acquisition and data management systems. It includes support for mapping assets of the entire distribution network at and below the 11 kilovolt (kV) transformers, such as distribution transformers and feeders, low-tension lines, poles, and other distribution network equipment. It also covers adopting IT applications for meter reading, billing and collection, energy accounting and auditing, and redressal of consumer grievances. It supports the adoption of management information systems and establishment of IT-enabled consumer service centers. After completion, the energy audit data are verified by an independent agency appointed by the Ministry of Power.

Part B includes distribution-strengthening projects such as renovation, modernization, and strengthening of 11 kV substations and transformers/transformer centers, reconductoring of lines at the 11 kV level and below, load bifurcation, feeder separation, load balancing, installation of high-voltage distribution systems (11 kV), use of aerial bunched conductors in densely populated areas, replacement of electromagnetic energy meters with tamper-proof electronic meters, and installation of capacitor banks and mobile service centers.

Underpinning the R-APDRP are technical solutions designed to improve the efficiency of distribution companies, adopted to different degrees by different states. Solutions such as energy audits, asset mapping, and power procurement planning have had limited take-up, while solutions such as metering of the distribution transformers, low-tension aerial bunched conductors, and spot billing have been widely adopted (figure 6.7). Andhra Pradesh, Himachal Pradesh, Delhi, Gujarat, Maharashtra, Madhya Pradesh, Karnataka, and West Bengal lead in these good practices.

If successfully implemented, the R-APDRP can transform utility operations and service delivery mechanisms. But no state has completed Part A, though some are in an advanced stage of execution. The key issues affecting implementation are:

- *Change management.* Implementing such a large IT-based program requires widespread changes in the utility’s business processes because IT needs to be integrated into commercial operations. A major issue is rollout without sensitizing utilities about the extensive change management that needs to go hand in hand with it. The organizational structure needs to be aligned to the new IT-based systems. Very few utilities have addressed this aspect so far.

Figure 6.7 Implementation of Technical Solutions

Source: World Bank calculations.

- GIS mapping.* The R-APDRP requires GIS-based mapping of all assets and consumers, but in India there is a general shortage of vendors with the required skills and the ability to take up assignments on a large scale. Also, utilities lack the resources to carry out field checks of the data collected and to regularly update system information. Without meaningful and current data, the energy audit and loss estimation exercise loses its meaning. There have been delays in implementation, and in some cases the timelines for this activity are unrealistic.
- Metering process.* The incompatibility of current meters with communication modems has made it difficult for utilities to implement remote meter reading. Thus automated meter reading is possible for high-tension consumers only, while meter reading for other consumers remains manual. Losses cannot, however, be greatly reduced until the manual interface is removed from meter reading.
- Program implementation.* The IT consultants hired for the R-APDRP are not well integrated into utilities' implementation teams. Utilities, which generally have few IT skills, find it hard to monitor the progress of the IT consultants. In addition, the timelines for implementation have usually been unrealistic, so resources are unavailable when needed. Lack of timely, effective monitoring has meant responses by all stakeholders to implementation problems have been slow.
- Contractor capacity.* R-APDRP contracts for multiple states were awarded to a single agency without assessing its capacity to deliver on time. Technical

criteria were not sufficiently specific on bidder capacity, and financial bids did not always cover all items, affecting the quality of implementation.

Metering and the use of technology have immense potential to improve efficiency even in rural areas, as seen in Haryana, where innovative approaches are being piloted (box 6.5).

Box 6.5 Impact of Metering on Operational and Financial Efficiency in Rural Haryana

A program for demand-side management and loss reduction was initiated as a pilot in the Singhran and Chirod villages of Haryana in December 2012. Given sociopolitical sensitivities on charging for power in rural Haryana, the utility, Dakshin Haryana Bijli Vitran Nigam, started its loss-reduction drive with a pilot in an area that enjoys political support for power reforms. Under this program all consumers are provided high-quality and almost uninterrupted supply against 100 percent payments for energy consumed. The infrastructure in these villages was strengthened, and insulated overhead conductors were provided to prevent unauthorized wire-tapping. All consumers have been metered, with meters installed outside the consumers' premises in meter pillar boxes. Consumers can view the meter display through a glass cover in real time, motivating them to be more energy efficient. Consumer indexing was also carried out, making transformer-wise energy audits possible.

Since the pilot began, energy input has declined 43 percent while billed units have risen 98 percent, collection efficiency has improved 26 percent, and aggregate technical and commercial losses have dropped from 77 percent to 26 percent. The utility managed this at an average cost of only Rs 5,560 (\$104) per consumer. No capital expenditure was involved because there was no need for more distribution transformers, conductors, or cables. In fact, the number of distribution transformers required and the transformer damage rate fell, due to a decline in overloading as consumption came down. Some 165 new consumers were added to the utility rolls (table B6.5.1). The combination of reduced theft (which improved utility finances) and better demand management has allowed the utility to increase supply from 11 hours a day to 22 hours.

Table B6.5.1 Savings Achieved by Pilot Project in Singhran and Chirod Villages

<i>Pilot project indicator</i>	<i>Saving achieved</i>
Number of consumers before pilot project	583
Number of consumers after pilot project	748
Average daily consumption before pilot project on 11 kilovolt Chirod feeder, January 2013 (kilowatt-hours)	6,000
Average daily consumption after pilot project on 11 kilovolt Chirod feeder, March 1–11, 2013 (kilowatt-hours)	3,254
Reduction in average daily energy consumption after installation of pillar boxes (kilowatt-hours)	2,746
Monthly savings (Rs millions [\$]) ^a	0.18 (3,370)
Approximate project cost for the pilot project (Rs millions [\$ million])	4.16 (0.08)
Estimated payback period (months)	23

a. The savings are calculated conservatively at the applicable energy charge per unit for the lowest tariff slab for domestic supply, which is 0–40 units.

Notes

1. External accountability covers features of the relationship between the government (as owner), the regulator, or the public, and the utility represented by its board; internal accountability refers to the relationship between the board and management.
2. The Act has basic provisions on board size and meeting frequency; the total number of directorships any director can hold and the remuneration directors may receive; the constitution and composition of an audit committee; and guidelines for preparing annual reports, financial statements, and audited account statements.
3. The sample comprises 37 distribution companies, 15 transmission companies, 15 generation companies, 1 corporation, and 1 holding company.
4. The 14 states were selected to ensure a range of locations and sizes. Utilities within these states were selected to include at least one distribution company and at most one other utility. Within that, selection was based on ease of access to senior management and likelihood of data availability. These decisions were all made in view of the difficulty and time-intensity of obtaining corporate governance data.
5. The Listing Agreement (Clause 49) of the Securities and Exchange Board of India lays out corporate governance requirements for companies listed on the stock market, which are more or less identical to those of the DPE.
6. In addition to the basic indicators listed in table 6.1, the “detailed” index includes indicators on internal processes and the relationship with the government—in particular, the existence of other specialized board committees, having an independent director heading the audit committee, preparing annual accounts on time, having an average CMD tenure of at least three years, lack of government influence over routine and recruitment decisions, existence of enterprise resource planning or an advanced management information system, use of performance-linked incentives, consideration of merit in promotion decisions, and existence of a clearly defined employee training policy.
7. While deeper analysis of the political economy of change would be required to come to a definitive conclusion, it is instructive that the initial impetus for change in these three states (including the privatization of distribution in Delhi) appears to have come from the government and political leadership. In all three cases the fiscal burden of a poorly performing power sector and consumer unhappiness with constant power cuts seems to have created the political will to take steps to not only improve the situation but also turn the sector into a source of comparative advantage for the state.
8. Running the regression with 2011 utility financial performance as the dependent variable, the coefficient on executive directors remains negative and significant, but the coefficient on independent directors loses significance, though it remains positive.
9. Prior to the establishment of independent regulators, the state governments were responsible for fixing electricity tariffs for their SEBs.
10. Other papers on regulatory governance have followed similar strategies for benchmarking regulators. For example, see Andres and others (2007). Similarly, the Electricity Governance Initiative has created a toolkit for assessing regulators, benchmarking best practice, and promoting accountability among electricity governance bodies; see Dixit and others (2007).
11. *Suo motu* describes an act of authority taken without formal prompting from another party. The term is usually applied to actions by a judge taken without a prior motion or request from the parties.

12. The results are robust across performance data from 2010 to 2011. See Pargal and Mayer (2013) for details.
13. For their part, discoms are often unable to reduce losses according to the schedule agreed with the regulator. But the estimation of transmission and distribution losses is not transparent, so there is often disagreement over this amount.
14. Borrowing against regulatory assets is becoming less feasible: since commercial banks are not sure how to value regulatory assets that may or may not be worth their face value, discoms can no longer borrow up to the full amount of the regulatory assets they own.
15. Actual cost is estimated by calculating the cost per new connection released thus far (money disbursed divided by number of connections released) and multiplying that by the total expected number of connections.
16. This loss figure is estimated as the product of the total number of rural consumers and the gap between average revenue and average cost.
17. Urban areas with a population of more than 30,000 except in the hilly and North-Eastern regions, where towns with a population of more than 10,000 are covered.

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Moving Toward Efficient and Effective Service Delivery

This review has shown that multiple stakeholders play a role in improving sector performance. Moreover, there are inefficiencies at each level of the sector value chain that, if minimized, could generate considerable cost savings to be passed on to final consumers, either in improved service or lower tariffs, as Chile managed to do (see appendix K). This would also reduce the burden on the exchequer and increase the competitiveness of India's economy.

Both central and state governments have an important stake in creating a robust operating environment, while staying out of the day-to-day business of utility operations. The central government particularly may need to fine-tune the design and execution of its flagship programs so that the envisaged benefits are actually realized. And it may need to coordinate grants from multiple programs to create a larger "carrot" that can only be earned by consistently good performers.

Lenders and regulators represent other groups of important stakeholders. Lenders who have been allocating money to the power sector without adequate due diligence need to be more discerning. Regulators need to fulfill their mandates in a transparent and accountable fashion—their role in supporting the sector on its path to financial recovery and commercial viability is critical.

Finally, the sector needs to be monitored regularly so that timely action can be taken to address problems. So far, poor quality and paucity of critical data have handicapped management and oversight.¹ The sector is still a long way from taking data collection seriously, which it needs to do to present relevant information to the public, make informed decisions, and ultimately create a clear sense of accountability among managers.

The main conclusions flowing from the review and suggestions for action are presented below.

Align Stakeholder Incentives

The central government's grant-funded programs should be used to induce better performance in the distribution segment. The large centrally sponsored programs—the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and the Restructured Accelerated Power Development and Reform Programme (R-APDRP)—can promote responsible behavior by utilities and state governments if disbursements are tied to utilities demonstrably achieving financial and operational performance targets.²

Ratings of utilities should be consistently used in lending decisions. The Power Finance Corporation's (PFC) and Rural Electrification Corporation's (REC) consistent use of the ratings recently developed by the Ministry of Power (2013) as a core input in their lending decisions holds promise. Since the PFC and REC are the leading lenders to the sector, using these or similar ratings would send a clear signal of the need to achieve and maintain strong financial and operational performance.

State governments could encourage responsible action by lenders and utilities. They can offer guarantees for utility borrowing that are contingent on prior, publicly announced actions to be taken by the utilities. Guarantees can be a powerful inducement for lenders to push utilities to meet key financial and operational performance targets. They also directly create an incentive for utilities to comply because obtaining a guarantee would increase their access to funds, as well as lowering the cost of any funds made available.

State governments ought to be held accountable for sector performance. State governments have not always endorsed proposals by utilities to file for tariff revisions and at times have not even permitted regulators to increase tariffs (even using section 108 of the Electricity Act of 2003 to this end). State intervention has frequently hurt the continuity of top utility management. States also need to be held responsible for making timely and complete subsidy payments as restitution to the utility, when they mandate below-cost supply of power to specific consumer groups on social or political grounds. The central government's budgetary transfer to the state could be a potential source for making up the shortfall if the state government does not make the payments due. Another approach to enhance state government accountability is to encourage public announcement (on the web, in the news media, and so forth) of the state government's sector performance targets and promote regular monitoring of their achievement by civil society organizations, think-tanks, and the like.

Strengthen Regulatory Governance and Processes

The autonomy of regulators is essential to their ability to fully implement their mandates. Widespread concerns about the objectivity of decisions and autonomy of decision making arise from the “revolving door” among the regulator, utility, and government that is one result of the narrow pool of qualified staff in the sector. An option would be to establish a common pool of technically

specialized regulatory staff that could work across states and regulatory commissions. It could be a permanent national cadre of staff, possibly under the aegis of the Forum of Regulators (FoR). Financial autonomy of regulatory agencies could also be enhanced by charging regulatory expenses to the state's consolidated fund so that the state electricity regulatory commission (SERC) has a dedicated source of funding, independent of the state budgetary process. Perhaps most critically, safeguards need to be developed against the misuse of section 108 of the Electricity Act of 2003, which permits states to "direct" the SERCs in matters of public interest. While this provision was apparently intended to provide a check on "rogue" regulators, it has in practice been employed to clip the wings of the SERC. A possible option is for the Appellate Tribunal (ApTel) to be the arbiter of whether a specific government directive is in the public interest (and to define the public interest).

*The SERCs need to develop greater technical capacity to design and implement regulations, monitor compliance, and penalize noncompliance.*³ Such capacity can be brought in by expert consultants, or developed through twinning arrangements across compatible states, possibly with the assistance and guidance of the Central Electricity Regulatory Commission (CERC). The CERC could, on behalf of the FoR, help SERCs identify lacunae to be filled, and help them competitively select professional technical advisory consultants to undertake the studies required (such as cost of service, or research to determine cross-subsidy and other charges) and to provide their staff with training and support. Funding needs to be ensured so that regulators have adequate numbers of appropriately trained professional staff, and access to training, research (possibly in partnership with the CERC or under the FoR to ensure economies of scale), and expertise in key disciplines such as law, economics, finance, and regulation.

Regional regulators can promote regulatory independence. The limited ability of the SERCs to penalize state-owned utilities (Berg 2013) and overcome state-level political considerations points to the need to review the regulatory model and adjust it if necessary. Potential structural solutions that narrow the scope for state governments to intervene in regulatory matters include replacing the 28 SERCs with four or five regional regulators, which would be responsible for regulating the sector in a group of states, thus increasing the distance between the regulator and the utilities and state government and also slowing the revolving door. Fewer regulators would also require fewer technically qualified staff and would likely be less handicapped by the prevailing shortage of trained personnel.

The regulator's credibility and effectiveness can be enhanced by increasing transparency in the regulatory process. This would entail holding open hearings, with agendas and minutes of the proceedings published in a timely fashion; inviting and publishing comments on regulatory proposals in local languages; and making all decisions and each step in key processes public.⁴ Transparency also involves publishing studies (such as results of customer satisfaction surveys) and holding open meetings to discuss their findings. Finally, the regulator must publish its budget and accounts on the web on time.

Robust mechanisms to promote accountability of regulators should be developed. Given the general lack of involvement of state legislatures, consideration could be given to alternatives such as reporting every six months, possibly through the FoR, to a standing Parliamentary Committee. The CERC through the FoR may need to consult broadly and develop a set of options to increase accountability. One suggestion is for periodic performance monitoring and evaluation of regulators by the ApTel and publication of the results.

Implement Key Regulatory Mandates

Retail tariffs should not be allowed to pass through upstream inefficiencies to the final consumer. They should take account of service quality and the appropriateness of power purchase costs.⁵ Regular cost of supply and cost of service studies (that account for variations in geography, population density, and the like) need to be commissioned and performance tracking needs to be undertaken to feed into tariff determination so that tariff increases are linked to efficiency improvements; tariff orders should cite these studies as the bases for tariff determination.⁶ As underlined by the Shunglu report (Planning Commission 2011), *suo motu* revision of tariffs is within the regulators' power and must be undertaken if utilities do not put forward the necessary petitions on time. Related to this are "regulatory assets," which have been permitted to reach unsustainable levels (Rs 700 billion [\$15 billion] nationwide with annual interest costs of around Rs 95 billion [\$2 billion]).⁷ Not only must such a buildup not be permitted again, but an immediate solution also needs to be found to the problem of receivables, which cannot reasonably be expected to be dissolved within three years, as mandated by the ApTel, because the tariff increases required would be unacceptably high.⁸

Standards of performance need to be clearly specified, measured, and made public. Data on basic measures of service quality (outages by circle, distribution transformer failure rates, and system average interruption duration and frequency) need to be made public and regularly updated by the SERCs, as should data on penalties imposed and the reasons for imposition. Utilities can be mandated to implement (through third parties) consumer satisfaction surveys and to provide the results to the SERCs and the public.

Regulators can create incentives for performance improvement by benchmarking utilities against each other. The FoR can publish annual utility-wise achievements ("league tables") on standards of performance, operational indicators, service quality, and so on. It can also help states learn from each other, for instance, through an annual conference of utilities and SERCs to showcase successes and share experiences. The Ministry of Power might itself consider establishing a virtual platform for utility cooperation (something for utilities that is similar to the FoR for the SERCs).

Regulators need to determine the charges required for implementing open access. They need to take the initiative in putting in place the preconditions (such as wheeling and transmission charges and the cross-subsidy surcharge, a path for

cross-subsidy reductions, and so forth) for open access to both transmission and distribution. The market for merchant sales has collapsed, and open access to distribution is needed if it is to contribute to balancing demand and supply of power. Open access and available evacuation capacity are also necessary to permit third-party sales to compensate generation companies if distribution companies (discoms) fail to honor their power purchase agreements (PPAs).

International experience with retail competition, through the separation of “carriage” and “content,” needs to be considered when implementing retail competition. It is advisable to pilot this separation to ensure that the institutional preconditions for successful implementation can be met.⁹ A major cautionary note on separation of carriage and content is the need for appropriate institutional capacity at the state level to incentivize the state discom (the carriage provider) to invest in reducing aggregate technical and commercial losses and strengthening wires systems (see appendix L).¹⁰ Also, in a situation of bulk power shortage, it will be difficult for new content providers or retailers to source adequate reliable power and enter the market to compete with incumbent suppliers.

Improve Corporate Governance of State Utilities

Compliance with the guidelines on corporate governance issued by the Department of Public Enterprises (DPE) can help insulate utility operations from state interference. Empirical analysis underlines the potential benefits from professionalizing and empowering utility boards, reducing the number of executive directors, and bringing in more independent directors, as prescribed in current guidelines for corporate governance of central public sector undertakings issued by the DPE. The central government should consider requiring state utilities to comply with these guidelines. Further, independent directors should be appointed by a committee that includes entities such as the Central Electricity Authority (CEA) or other representatives of the public interest to avoid capture by the state government. Beyond that, an arm’s-length relationship between the government and the utility can be institutionalized more easily if utility articles of association specify clear limits on the role of the government. The stock market can be an effective monitoring and enforcement mechanism for governance of listed companies. One option is to mandate that utilities comply with listing requirements (“shadow” listing) as a precondition for central or other support, as was done in West Bengal to good effect. This can bring greater accountability to utility boards, while also restricting state interference.

*Complete financial and operational unbundling is important to improve the accountability of each unit in the value chain.*¹¹ This can help identify where inefficiencies or performance shortfalls occur and, by increasing accountability, improve incentives for performance. Full vertical unbundling with separation of accounts, staff, and decision making is also a necessary step toward competition in supply. Since unbundling on its own will not lead to commercialization, it is also important to consider other ways of bringing in efficiencies, such as divesting an ownership share to central public sector undertakings like the National Thermal Power

Corporation (NTPC) or the Power Grid Corporation of India (PGCIL), which are recognized for strong results and which, as equity owners, might have both an interest in pushing for better performance and the ability to do so.

Incentives for utility performance can be strengthened by using memorandums of understanding (MoUs), following the practice of central public sector undertakings. MoUs on performance between the utility and the state government (owner) with clear consequences for not reaching targets (loss of performance bonuses for managers, no contingent guarantees, and so forth) can be effective if they go beyond lip-service on requirements (they “bite”), are made publicly available, and are subject to transparent monitoring by third parties.

Promote Responsible Lending to the Sector

Loan disbursements need to be linked to performance and creditworthiness. The major lenders to the sector are the government-owned financial institutions, the PFC and REC. Lacking the profit orientation of commercial lenders, they may not have adequate incentives to push utilities to improve financial performance. By encouraging the PFC and REC to consider in their lending decisions the recently developed rating of utility performance, the Ministry of Power can move the sector toward more robust assessments of creditworthiness than merely relying on implicit and explicit government guarantees. An additional step is for financial restructuring plans to require disbursement of funds from financial institutions, banks, or government to be linked to a few key performance measures that would be specified up front.

Lenders need to be penalized for inadequate due diligence. The expectation that the state government would backstop loans to its utilities has historically led to relatively profligate (or politically directed) lending to the sector by private and public sector banks, with little concern for the creditworthiness of the discom as the ultimate power offtaker. In many cases sector exposure limits have been reached, with several banks exposed beyond their net worth. Incentives will be aligned only if lenders are not bailed out when they have made poor decisions. At the same time lenders need to be empowered to resist political pressure to lend and should have step-in rights to bring in new management when there is a default or noncompliance with financial covenants. A possible way of side-stepping political pressure would be to adapt the United Kingdom’s system of “warehousing of shares” in which management control of the utility is diluted by bringing in a neutral third party (such as a law firm) to represent the public interest on the utility’s board and to push management to improve performance.

Ensure Availability of High-Quality, Updated Data

Data need to be collected and updated regularly for decision making. Sector monitoring can only be as good as the data on which it is based, but reliable data consistent over time are not there. This hampers planning, decision making,

implementation monitoring, and compliance enforcement, hurting all players and both internal accountability (for example, of utility management to its board and owners) and external accountability (for example, of the utility, government, regulators, and consumers and civil society to each other). Operational and technical, financial, and service delivery data need to be regularly and systematically collected with a view to using them for decision making, performance monitoring, trend analysis, and planning.¹² The central government could introduce a statutory requirement for regular primary data collection by utilities, with the effort being appropriately budgeted so that data can be professionally collected, vetted, and maintained. Data also need to be updated regularly. Whistleblower protection should be provided to utility staff who point out irregularities. And incentives should be provided for ideas on how to prevent “cooking” of data. It is essential that data and analysis be made public, not only to permit stakeholders (including civil society) to use them, but also as a quality check as this permits information vetting.

Feedback loops are essential to incentivize regularly collecting and updating data. Performance targets should be published up front and achievements regularly tracked and made publicly known. Incentive schemes should rely on progress in achieving targets (similar to R-APDRP) including levels of customer satisfaction, with third-party monitoring. Regulators should also systematically use data for performance benchmarking and encourage their use by researchers and academics, which would create another constituency for collecting high-quality data. At a more macro level, data can be used for specialized tracking of policy implementation, and repeated surveys can help policy makers identify trends and monitor sector developments.¹³ Further, data on compliance with commitments (such as timeliness and completeness of subsidy payments, and payment of own bills) by state governments should be published to permit civil society to hold them accountable. Most important, data need to be made available in a user-friendly format, including on the regulatory commissions’ websites, in newspapers, and in other media channels.

Reinvigorate Planning and Coordination Mechanisms

Planning needs to be strengthened. Key concerns that emerged from this review relate to systemwide planning and coordination of generation and transmission investments; the overall strategy for private involvement in transmission; the realism of the government’s fuel availability assessments; the general absence of power procurement planning by utilities; and the need for sharing good practices. The delicensing of generation and decentralization of decision making after unbundling raise concerns about appropriate sequencing and coordination of investment in generation and transmission, ensuring adequate transmission capacity, and whether the CEA’s role in leading network planning at the central level and in coordinating with states must be strengthened. This has become more important with the entry of more private investors to the sector, especially in generation. Private investment in off-grid solutions depends heavily on the

timetable for extending the grid to unserved areas.¹⁴ In addition, there is a need to bolster integration of renewable energy into the grid, and to plan for its evacuation.

Coal India's performance to support the power sector needs to be reviewed and monitored. Its monopoly on coal production and sales in the country, coupled with its inefficiency, has led to consistent shortfalls in coal availability compared with official estimates over the past two plan periods (2002–07 and 2007–12). Considerable investment in thermal power plants, with PPAs based on the projected availability of cheap, domestic coal, is now likely to remain stranded. Inadequate diversification of fuels and development of reliable fuel sources could even put at risk the country's energy security. The government's role in facilitating bulk procurement of fuel from abroad and in resolving uncertainty over domestic availability and prices of coal and gas, issues related to the structure, management, and productivity of these industries, needs further debate.

The CEA can act as the knowledge repository for the power sector. The CEA's role was reduced when the sector opened up. For example, the need for technical clearance from the CEA was done away with, along with the requirement for generation licensing. It may be time to bring back the technical and coordination role of a highly specialized agency such as the CEA. It can ensure dissemination of best practices across states on key issues like power procurement, operation and maintenance practices, loss reduction, and new technologies, while also helping build capacity in state power departments and utilities for comprehensive assessments and projections of demand and supply, contracting, and portfolio planning. The CEA can also be used as a platform for sharing experiences with innovations or new interventions like private participation in generation, transmission and distribution, or rural feeder segregation.

Explore Different Models to Improve Distribution

Many approaches exist to attract private participation to distribution. India's size and diversity have created the opportunity to experiment with and learn from different models of service provision, including private sector participation through, for example, joint ventures (Delhi), franchising (Bhiwandi), and management contracts. Key issues with attracting outside expertise and investment for improving distribution are a lack of reliable information on asset quality (including asymmetry of information in relation to the incumbent utility); very different demand, needs, and ability-to-pay of rural and urban consumers who are served by the same utility; long-lived assets that require heavy investment up front; and sensitivity of government to potential for "extraordinary" profits being earned by private investors leading to excessive conditionality (and reduced interest by potential entrants in the newer franchises offered).

Potential approaches could thus consist of one or more of the following:

- Make provision for learning by doing, starting with management contracts or franchises that permit the discovery of the true state of assets and that bring

basic efficiencies to operations before specifying investment requirements over the longer term.¹⁵

- Separate urban and rural areas and consider license, franchise, and public-private partnership models¹⁶ only in urban areas, while letting state discoms remain responsible for rural supply (or separately contract out specific functions, like revenue collection, to a rural franchisee) and assign low-cost public-sector generation (such as NTPC PPAs) to them—the private urban operators would be responsible for procuring power for their own consumers.
- Encourage urban franchisees to gradually expand their service to cover rural areas (as through a series of concentric circles) so that learning consolidates over time.

Variants of this basic approach could include permitting private entrants to provide enhanced levels of service reliability for additional fees paid over the basic, regulated tariff and specified service quality for which they are accountable. Benefits from experimentation will be enhanced if benchmark competition is encouraged in states with multiple discoms; criteria should include service quality and reliability, operational efficiency, and public satisfaction.

Promote Electrification in a Financially Responsible Manner through Different Delivery Models

As India moves to electrify the remaining quarter of its population, it faces different challenges from earlier phases. Ensuring the availability of reliable and affordable power is important to bridge the gap between village electrification and household electrification and to maintain the access extension achieved to date. The surge of new connections under the RGGVY consists of low-volume consumers whose consumption is typically estimated and who are charged a tariff considerably below cost—both elements likely to financially overwhelm utilities if not prioritized for attention.

Rural service delivery will become viable only if discoms are compensated fully for supplying power to such consumers. For this, the cost of service delivery needs to be known, and the state needs to make up the shortfall in discom revenues from supplying rural consumers. Cost of service modeling and associated studies must be undertaken, and funding needs to be allocated to this in the state budget. While increasing rural loads will make it cost-effective to meter, bill, and collect payments, technology innovations and rural collection franchisees can help reduce the associated transaction costs.

A common agency for planning and monitoring grid and off-grid investments at the central level can promote coordination. Such an institution can lead the development and regular update of state rural electrification plans as well as provide a countrywide picture of the rollout of grid as well as off-grid investments. Coordination would require more reliable information on people without electricity living in villages with power (important for state utilities) and living in villages without power (important for off-grid providers).

Supporting productive uses is critical for aggregating the rural load and improving the commercial viability of rural service delivery. The experience of Indonesia and Peru suggests that capacity building for productive uses of electricity in rural areas has many benefits (see appendix M). It increases the productivity of rural businesses (generating local income), enables a more efficient use of the supply infrastructure, and increases the revenues of discoms, as these commercial consumers can be expected to pay tariffs that cover the cost of service. Complementary services for enhancing productive use include access to affordable microfinance as well as to information and knowledge (such as education, training, business development services, dissemination campaigns, and qualified human resources).

Households above the poverty line should be included in the ambit of rural electrification programs to enhance social cohesion and the sustainability of the access expansion achieved. In several states the exclusion of households above the poverty line has caused problems such as illegal tapping of networks or consent withheld for extending the network across land under their ownership. In some cases legal injunctions have been obtained to prevent project discrimination on economic grounds. To avoid such issues some states (for example, Andhra Pradesh, Tamil Nadu, Jharkhand, and West Bengal) have granted free connections to households above the poverty line at their own expense, even though they are ineligible for RGGVY funds.

Billing and collection systems in rural areas should be improved. Prepaid meters could be used to reduce utilities' commercial risks while also allowing rural households to have more control over consumption. In fact, the pay-as-you-go system is very familiar to rural users of mobile telephony prepaid cards. Other innovations, widespread in East Africa, allow rural consumers to make various payments through their mobile phones (such as the M-Pesa system in Kenya). India could try this arrangement to reduce transaction costs for all parties. It may be beneficial for interested state utilities to explore management contracts with private operators who can deploy prepaid metering technology.

Rationalizing domestic tariff structures will improve targeting and reduce the fiscal burden. An accurate system for identifying households below the poverty line can better target delivery of subsidies to the poor. Until such a system is functional, it would be useful to work toward rationalization of tariff structures through volume-differentiated tariffs instead of incremental block tariffs. In volume-differentiated tariffs, households are grouped by total monthly consumption and each household in a given group pays the same (constant) tariff for all the power it consumes. States with fairly low fiscal costs of subsidies achieve this by limiting the subsidy, restricting how many households receive the subsidy, and by charging a cross-subsidy to some households.

Notes

1. For instance, updated employment data are not available for all state utilities, making basic productivity comparisons difficult. Likewise, a lack of metering means that consumption cannot be accurately measured or billed.

2. Payment release could be conditional on concurrence with the performance report by the lenders' representatives on utilities' boards.
3. Concerns have been raised about the information asymmetries between the CERC and the PGCIL, and how this may affect the CERC's oversight of the transmission system and ability to provide a level playing field for potential entrants.
4. Webcasts of regulatory hearings would greatly enhance transparency and likely improve public information and participation.
5. Realistic efficiency targets for state-owned generation companies need to be set and monitored to encourage better use of capacity. This is especially important for sales to distribution utilities whose power purchase agreements are subject to cost-plus regulation.
6. Regulators should move to multiyear tariffs based on an agreed projected performance trajectory (taking account of power procurement cost and generation performance, efficacy of capital expenditure, and reduction of distribution losses) to provide greater certainty to utilities and to incentivize immediate efforts to increase efficiency.
7. See appendix J.
8. For the discoms in Delhi, which are majority privately owned, central government assistance through concessional lending or backstopping the issuance of bonds by the affected distribution companies may be the only way of buying enough time to resolve the issue.
9. The primary advantage of such separation is fixing accountability for reducing technical losses. For the largest customers (1 megawatt and above) who contract directly with a generator, the benefit would be the disappearance of the cross-subsidy surcharge currently levied by the discom, since the discom's revenues would come from wheeling charges for the use of its network. The global experience with separation, particularly in Europe, is that far fewer customers than anticipated switch from the incumbent retail supplier. Successful retail competition, as in New Zealand (see appendix L), highlights the importance of institutional support to allow customers to actually take advantage of the retail choices open to them. In the United States, by contrast, despite retail competition, if the generators' market is distorted there is no long-term consumer benefit from switching retail suppliers. European studies also show that despite different levels of competition, retail tariffs for customers only decreased when retailers were able to buy cheaper power in bulk, and not due to the number of actors competing for end-customers.
10. This model, prevalent in Australia, the Netherlands, Nordic countries, and the United Kingdom, makes significant demands on system operators, regulators, and the like, as well as requiring adequate metering technology, functional unbundling of the system, and ways of managing the price volatility faced by consumers.
11. Separate distribution from transmission if the utility (state electricity board) is large enough to warrant this and if managerial capacity is not a constraint (the Electricity Act of 2003 mandates separation of generation from transmission).
12. Three priorities: financial data, with quality and coverage (variables collected) to be improved along with the adoption of standard accounting norms (or regulator-specified norms) and penalties for delays in finalizing and auditing accounts; operational data, with enhanced frequency and collection of data from the field (currently very limited), covering standards of performance and measures of reliability and quality, avoiding manual intervention in data collection, and randomly auditing the data collected; and state government commitments, such as subsidy payments.

13. The Implementation of Reforms Index, the Sector Outcomes Index, and the Analytic Hierarchy Process Index illustrate the potential options that can be considered (see chapters 4 and 5).
14. Given limited state capacity, a central planning agency should assist the states in preparing their own rural electrification plans (clearly highlighting areas where provision of grid supply will not be possible or will be unviable), integrate these plans, and make this information widely available.
15. The incumbent franchisee has an information advantage when bidding for concessions or privatizing the utility (if that is envisaged in the next stage); appropriate mechanisms for capturing this knowledge or handling the information advantage will need to be developed. They should provide incentives for franchisee performance but also allow for an open competitive process.
16. The Delhi utilities are technically public-private partnerships as they are joint ventures between the government and the various licensees.

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Advantages of the Point of Connection Method in Assessing Transmission Charges

A postage stamp rate is a flat per kilowatt charge for network access within a particular zone, based on average system costs. Postage stamp transmission tariffs allocate total system costs to consumers on the basis of the ratio of load share to energy share. A customer pays a transmission charge equal to the total system cost, weighted by their consumption as a share of total consumption. This method results in higher costs (above marginal costs) because it incorporates historical fixed costs. It does not reflect marginal costs except in a special hypothetical circumstance where all generators are at equal distances from load and where the load on each line in a network is equal. The cost for transmitting power within the zone is independent of the transmission distance. A generator transmitting to a customer in a different zone would have to pay postage stamp charges for the zone of origin and the zone of delivery, and any intervening zones. This accumulation of zone access charges is often called “pancaking.” Thus longer distances increase the likelihood that more than one zone will be crossed, increasing the total transmission cost.

Although postage stamp rates provide a way to recover the fixed costs of the network, they provide no information about congestion. The main advantage of using this method is that it is easy to administer. In conclusion, a postage stamp tariff is most suitable when the area in consideration is relatively small, and when flows are relatively simple and do not cause disproportionate load on any single part of the system.

The genesis of the revised framework of the Central Electricity Regulatory Commission for sharing transmission charges and losses lies in the National Electricity Policy, which mandates that the national tariff framework implemented should be sensitive to distance and direction, and related to quantum of power flow. The National Electricity Policy requires transmission charges to

reflect network utilization—that is, they must address congestion and thus improve efficiency and reduce cost for the end customer (the discom). Point of connection (POC) tariffs are based on load flow analysis and capture utilization of each network element by customers.

The core principles of the POC methodology are as follows:

- The interstate transmission system (ISTS) is a single integrated “common-use” national network for use by all designated interstate transmission customers.
- All designated interstate transmission customers would have to pay relevant charges to transmission providers depending on where they are placed in the national network. For example, for generators close to a load center, the transmission charges assessed would be relatively lower, and vice versa. Similarly, demand centers near generation hubs would have relatively lower charges allocated to them.
- Locational pricing establishes a merit order in which generators further away pay more. This prevents any one-on-one transaction with the transmission provider—like individual contracts—and instead provides a transparent pricing mechanism.

Thus transaction management (including on the trading platforms) becomes simpler and merit order is maintained.

Under this framework, any generator node is required to pay a single charge based on its location in the grid to gain access to any customer anywhere in the country. Similarly, any demand node will also be required to pay just one charge to get access to any generator in the grid. This is based on load flow studies conducted for each node, one at a time. The same principle holds for transmission losses that a generator node or demand node has to bear. With the implementation of the POC transmission pricing mechanism—where transmission charges are differentiated by location—power generators will have to take a view both on transmission costs of electricity and transportation costs of fuel.

The new approach, apart from addressing network congestion, also greatly facilitates fair and transparent competition for Case 1 bids. Under the previous methodology, Case 1 bid processes were severely distorted because of pancaking, and this also resulted in pit-head/hydro plants not being competitive for interregional bids. The impact of pancaking was further amplified in such bid processes because of application of escalation factors to transmission charges over a 25-year period. The new POC regulations also specify the methodology for sharing transmission charges for the use of ISTS and transmission losses in the ISTS, in accordance with the National Electricity Policy and Tariff Policy.

Sources: CERC 2011; NLDC 2010.

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Measures to Overcome Barriers in Integrating Renewable Energy into the Electricity Grid

Grid integration is the most common barrier to scaling up electricity generation from renewable energy sources, for two key reasons: conventional transmission lines are not designed to handle sudden spikes or drops in electric current that are characteristic of variable, intermittent, and uncertain generation from renewable energy sources; and renewable energy sources are often in remote locations with weak transmission networks that provide less grid support during system disturbances and are usually not fault-ride-through capable.

To manage the variability of renewable energy in system operations, the following strategies are effective (Madrigal and Porter 2013):

- *Forecasting.* As penetration of variable generation increases, appropriate forecasting methodology and modeling become essential to influence dispatch operations at different time frames (days, hours, and tens of minutes ahead); this minimizes fuel and short-term reserve needs. To have effective forecasting in place, it is pertinent to define the responsibilities of renewable energy providers in making forecasts or key inputs available.
- *Subhourly markets.* Shorter market clearing periods are necessary to incorporate updated variable generation forecasts. This also improves access to existing generation units or other ancillary services (such as balancing). As long as forecasting influences dispatch, subhourly markets can help in managing the impacts of generation variability.
- *Shorter scheduling intervals.* Submitting schedules closer to real time will allow for more accurate forecasts of wind and solar generation. This requires strong information and telecommunications systems, a well-structured process for linking short-term operations with real-time dispatch, and discipline in maintaining both of those on time. On the downside, shorter scheduling intervals

may lead to higher costs from the increased starting and stopping of conventional power plants.

- *Consolidating balancing areas.* Larger balancing areas (operational regions) improve both load diversity and the diversity of wind and solar generation, reducing overall variability of renewable energy resources. This is especially effective if variability in renewable energy resources in the different areas within the operational region is complementary.
- *Flexible resources.* Higher amounts of variable generation require flexibility in the generation system so that it can increase or decrease operations quickly and over a wide operating range. Having a variety of generation and nongeneration sources (such as storage) can effectuate this.
- *Grid codes.* Grid codes define the performance requirements (mainly voltage and frequency) of variable power generation, operational and dispatch rules, and specifications for interconnected grid planning. It is critical that grid codes be enforced and that appropriate tests be carried out strategically to ensure that old and new technologies comply with the standards.
- *Improving planning practices.* Technical planning is required to ensure adequacy of transmission and supply to meet supply security standards. Planning practices need to ensure that the contribution of renewable energy to supply adequacy and cost implications is correctly assessed.
- *Demand response and demand-side management.* These are direct requests from system operators or pricing strategies to change consumer demand. The natural progression of a demand response system is to fix any price distortions, introduce time-differentiated tariffs, and implement other pricing interventions to flatten peak demand (such as pricing overconsumption of reactive power).

Five broad principles derived from international experiences that should be kept in mind when expanding transmission systems are listed below (Madrigal and Stoft 2012):

- The additional cost of significant transmission expansion required by renewable energy sources is often offset by the incremental benefits of additional renewable energy generation.
- Transmission should be developed proactively, with providers building transmission with the intention of guiding efficient growth of the power system—as opposed to the provider reacting to committed renewable energy projects. Proactive planning will produce a more efficient outcome and result in timely provision of transmission services. An intermediate step is to perform

anticipatory planning, in which transmission does not guide generation investment or intend to reach the best resources but rather attempts to build lines in areas where generators are likely to be placed in the future.

- To maximize the net benefit of renewable energy resources, transmission lines should be built as if the transmission planner had control over both the transmission and generation investments—that is, by attempting to maximize the joint net benefit of transmission and generation. Although planners are unlikely to have direct control over generation, they can influence it by building and then appropriately pricing transmission lines.
- Appropriate transmission pricing is necessary to send the right locational signals to generators and to capture some locational rents (excess profits) for consumers. The locational signals intend to provide pricing incentives for developing the best combination of transmission and renewable energy generation resources.
- Transmission companies should recoup all efficient costs to ensure their sustainability. Any financial loss from allocating transmission to a generation source (such as a source of renewable energy) which poses challenges to grid operation should be compensated by a tariff that is fair and that causes minimal distortion to electricity generation and use.

Sources: Madrigal and Porter 2013; Madrigal and Stoft 2012; PGCIL 2012.

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Considerations for Attracting Private Investment in Hydropower

With a total potential of 148,700 megawatts (MW), hydropower is an important option to address India's energy shortages and limit the carbon intensity of its power sector. It is a reliable source for meeting peaking power requirements, and by diversifying the energy mix enhances energy security. However, India has exploited only 24 percent of this potential at the current installed capacity of around 35,000 MW. The share of hydropower in total power generation capacity decreased from 44 percent in 1970 to about 19 percent by March 2012. In the 11th Five-Year Plan hydropower achieved only 35 percent of targeted capacity addition,¹ with shortfalls in performance across both the public and private sectors.

Hydropower projects are subject to high risks stemming from the need for massive capital investments, complex project development processes involving coordination across multiple agencies, gestation periods that can extend to 10 years or more, poor or missing hydrological data and topographical sheets at the award stage, land acquisition and resettlement issues that can lead to huge delays in project preparation, and high construction risks and possibility of geological surprises—among other things. The need for environmental, forest, and other clearances from government agencies also contributes to uncertainty and implementation delays; for example, the majority of the 11th Plan hydropower projects were delayed by more than three years.

A review of current and upcoming hydro projects indicates that a radical change in the project portfolio is under way, with a move away from a public sector–dominated capacity mix (93 percent of current installed capacity is owned by states and the center) to private sector domination in the future (around 64 percent of planned capacity). The policy implementation framework for hydropower development in the country is in the process of adjusting to this change. A key issue that has been raised is the fact that, after the award stage, as approval and construction of the project begins, the involvement of government entities diminishes. This, added to the long gap between project award and

commissioning during which no revenues flow to the developer, increases the difficulty of attracting private investors to the sector.

Given the current state of development, even if the entire planned hydropower capacity comes online during the 12th Plan period, the share of hydropower will decrease to 17 percent. To overcome this and support private sector participation in hydropower, it will be important to address the following:

Ensure strong central and state leadership in project development implementation. Committed sponsorship and coordination among the central government and its agencies is vital for removing bottlenecks. These measures should include support for completing preliminary studies and for preparing detailed project reports, facilitating approvals and construction, and resolving disputes and difficulties. In addition, project implementation can be facilitated by the development of road infrastructure by the state government to allow transport of construction equipment and ease access to project sites, and by the construction of necessary evacuation lines by the state transmission company or the Power Grid Corporation of India Ltd.

Support policy actions by creating effective institutional structures, which aid development through the private sector and which facilitate time-bound actions. For example: all critical clearances should be facilitated by the government ideally through a single-window process, and requirements should be realistic; in line with international practice, consents and clearances should be obtained before the project is awarded. Ensure that allotted power projects cannot be cancelled, as it leads to protracted litigation—instead, a system of penalties and milestones such as in Himachal Pradesh should be implemented. Align the transmission development framework at the state level (as is the case at the interstate level) with generation development.

Realign incentives to ensure close coordination between the host government and the developer during the approval and construction phases. Some recommendations are to reduce the upfront premium charged from successful bidders, which is high in India compared with international benchmarks; to base project allocation on robust and comprehensive detailed project reports and monitoring systems; to adopt competitive bidding for awarding projects; and to establish an effective dispute resolution mechanism.

Ease financing through greater market certainty and risk sharing. An effective risk–return sharing model is needed as a “one-size-fits-all” approach is unsuitable for different states. The quality of documentation and studies provided to bidders also needs to be improved. Long-term power purchase agreements for hydropower projects are also necessary to reduce risk exposure for the developer/project. A separate market for hydro Case 1 needs to be considered and bid documents should be designed specifically for hydro projects. In addition, extending the existing cost-plus tariff regime beyond December 2015, in recognition of the high degree of uncertainty in hydropower and the need for assured returns, needs serious consideration.

Ensure regulatory certainty for cost approvals and pricing, which is critical for Indian and cross-border projects alike. Without confidence in the regulatory

environment, applicable jurisdiction, and price, project financing is difficult. A clear duty structure and licensing requirements are also necessary to encourage international developers to participate in the Indian market. In addition, hydro-bearing neighboring countries should also be considered as integral parts of the planning process and permitted to participate in Case 1 bids and be financed by Indian institutions, since India serves as a key market and shares the river basins with them.

Sources: Chatterjee 2013; Mercados EMI 2012.

Note

1. Some 5,544 MW of hydropower capacity was added out of the targeted 15,627 MW.

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Experience with Multiple Transmission Owners

Ownership of transmission services by more than one entity came about organically along with the development of national grids and the establishment of regional transmission operators (RTOs), transmission system operators (TSOs), and independent system operators (ISOs) in the country examples presented here. Unlike generation, the transmission system has a natural monopolistic structure. Not only is the number of players limited but issues to be addressed include appropriate distribution of costs of grid expansion and tariff setting. The fractured nature of the grid resulting from liberalization of the market and multiple owners is a concern for planning and security. At the same time, multiple owners create the need for greater coordination, better transmission planning, and implementation of measures to ensure reliability locally and regionally.

Examples of different market and regulatory approaches with multiple grid owners are provided below (and see table D.1).

Argentina—Argentina restructured its power system in the early 1990s, as part of a larger economic reform program that included the privatization of all state-owned industries. Transmission and generation assets were sold, mainly to foreign entities. Although the sector remained regulated, the government introduced competition by auctioning (concessioning) contractual rights to deliver services for specified periods under technical and reliability standards established by the National Entity for Electricity Regulation.

Argentine transmission companies are responsible for the operation and maintenance of their networks, but not for the expansion of the system. The concessionaire earns a fixed remuneration (for connection, transmission capacity, and energy transported), to ensure no distortion of spot prices of electricity. This aspect of regulation has worked well. It has improved quality of service and provided sufficient revenue for line maintenance and has encouraged greater efficiency. Although users pay for new transmission capacity, effective planning for the sector has been a challenge.

Table D.1 International Experiences with Market and Regulatory Organizations with Multiple Grid Owners

<i>Country</i>	<i>Transmission industry structure</i>	<i>Independent system operator</i>	<i>Entity responsible for planning/expansion</i>	<i>Country-specific remarks</i>
Argentina	Competitive: Period based concessionaires. 7 main companies and other independent companies that work under license by them	Present. National Entity for Electricity Regulation (ENRE)	No specific entity. Public hearing process is undertaken for expansion projects by the ENRE, which issues a "Certificate of Public Convenience and Necessity"	Planned expansion of the transmission lines is a bottleneck in the country's transmission sector and leads to expensive short-term investments
Australia	Partly unregulated: 11 companies in total. Companies in South Australia and New South Wales are privatized, the rest are provincially owned. Only 1 unregulated company (an interconnector, Bassilink), all others are regulated	Absent. Australian Energy Regulator regulates pricing and congestion management and oversees investments	Investment decisions are guided by requirements and standards set by state governments and Australian Energy Market Operator. The National Transmission Planner plans transmission in the National Electricity Market, a fully connected electricity market in eastern and southern Australia	Mixing regulated and merchant transmission investment regimes in Australia has been difficult. It has led to controversies, litigation, delays, and inefficiencies. One of the two merchant transmission companies—Murraylink—applied for transfer to regulated status because of regulatory uncertainty
Germany	Competitive. Dominated by four large electricity companies (RWE, E.ON, Vattenfall, and EnBW)	Four TSOs (RWE, E.ON, Vattenfall, and EnBW)	Owner of transmission line	While there are numerous market players in both markets, neither sector is considered competitive, as both are characterized by a high degree of vertical and horizontal integration, and are dominated by a few large companies
United Kingdom	Regulated. Companies are subject to price controls set by the regulator, Ofgem. 3 transmission licensees—National Grid, SPT, and SHETL	Great Britain System Operator—National Grid UK	Owner is responsible for planning and expansion	The arrangements under the British Electricity Trading Transmission Arrangement are based on bilateral trading between generators, suppliers, traders, and customers across a series of markets operating on a rolling half-hourly basis. Under these arrangements generators self-dispatch their plant rather than being centrally dispatched by the system operator

table continues next page

Table D.1 International Experiences with Market and Regulatory Organizations with Multiple Grid Owners
(continued)

Country	Transmission industry structure	Independent system operator	Entity responsible for planning/expansion	Country-specific remarks
United States	Competitive: More than 500 companies	Present in two-thirds of the country—Northeast, mid-Atlantic, Midwest, and California	RTO/ISOs plan, which is approved by state public utility commissions. Plans by investor-owned utilities are approved by the FERC	U.S. public policy largely compelled a transition in the electric power industry which has never been fully extended or standardized nationally (or at least throughout the FERC jurisdictional entities), resulting in continued balkanization of the grid and often significant differences in ownership structures and wholesale market rules between regions

Note: FERC = Federal Energy Regulatory Commission; ISO = independent system operator; RTO = regional transmission operator; TSO = transmission system operator.

Australia—Australia has a unique power transmission market as it allows for both regulated and unregulated ownership of transmission companies. Unregulated transmission prices are market based through trading in the wholesale market. Regulated companies receive income from a fixed charge subject to revenue caps set by the Australian Energy Regulator (AER) that provide for a commercial return to the business. AER approves an investment forecast for each regulated network. To encourage efficient spending, network businesses retain a share of any savings against their investment allowance. A service-standards incentive scheme ensures that cost savings are not achieved at the expense of network performance.

Although there is no independent operator, the Australian Energy Market Operator protects system security and prevents transmission congestion. The National Transmission Planner prepares the annual national transmission network development plan. It also provides a long-term strategic outlook (minimum 20 years) to complement shorter-term investment planning by transmission businesses (AER 2011). The mixed market of Australia has faced several challenges: a visible one is the lack of unregulated merchant transmission companies in the country. Because of regulatory uncertainty and financial losses, only one merchant company remains in the country—Basslink—operating between Tasmania and Victoria. The structure of the Australian transmission system has been in a state of flux and continues to evolve.

Chile—Transmission ownership in the Sistema Interconectado Central power system is dominated by Transelec. In contrast, the electricity transmission sector in Sistema Interconectado Norte Grande power system is distributed among several owners with five companies each controlling between 10 percent and 20 percent of total transmission capacity. Distributed ownership reflects the more decentralized development of the SING power system, which has grown to meet the needs of the mining and minerals processing sectors.

New regulated transmission investment is determined through a centralized process involving a holistic planning phase (the transmission “trunk” study) and a subsequent tendering process. Merchant interconnector investments are permitted, but there is little incentive to make such investments in the absence of certainty about the regulated return on investment.

Comisión Nacional de Energía—Chile’s energy regulator—is responsible for analyzing pricing, tariffs, and technical standards for energy production, generation, transmission, and distribution. In Chile responsible generators and network owners are also legally obliged to have contingency plans that enable them to effectively support emergency management and restoration activities. Superintendencia de Electricidad y Combustibles is responsible for monitoring and verifying such compliance (IEA 2012).

Germany—The German electricity industry is dominated by four large electricity companies (RWE, E.ON, Vattenfall, and EnBW), which together control 90 percent of the country’s generating capacity, almost the entire high-voltage transmission network, and about half the retail market. This structure, in combination with the congestion prevailing at all German borders with the exception of Austria, is thought to prevent effective competition from developing (EC 2007).

The four TSOs in Germany are also RWE, E.ON, Vattenfall, and EnBW. Thus they act as the system operating grid owners (system operators and owners) and work autonomously and independently of each other (for example, independent grid planning, grid operations, grid tariff calculations, and dispatch). This structure developed mainly for political reasons, and has led to many issues including the need for balancing separate power markets within each network. Attempts to separate system operators from transmission ownership have not been successful.

Norway—There are around 47 network companies in Norway; however, Statnett SF holds the position of the monopoly TSO. It is responsible for all high-voltage electricity transmission and distribution in the country. The central government owns a large proportion of the central grid through Statnett, while private companies, counties, and local authorities own the remainder.

The Norwegian Water Resources and Energy Directorate (NVE) is responsible for monitoring grid management and operations and determines an income cap for each network company: their income, which mainly derives from transmission tariffs, must not exceed the maximum permitted level determined by NVE. This system is intended to ensure both that grid companies do not make unreasonable monopoly profits and that cost reductions also benefit grid customers.

The United Kingdom—Three companies, responsible for maintenance as well as planning and expansion of their networks, dominate the market. The British Electricity Trading Transmission Arrangement made provisions for a single system operator—National Grid UK—in the country. Apart from being a regular transmission company, National Grid also ensures that supply and demand can be continuously matched or balanced in real time and works to regulate the three

transmission monopolies effectively to maintain market efficiency. Market participants have access to information to enable them to trade to balance their positions and self-dispatch their plant. The Grid Code is designed to permit the development, maintenance, and operation of an efficient, coordinated, and economical system for transmitting electricity; to facilitate competition in the generation and supply of electricity; and to promote the security and efficiency of the power system as a whole. To help achieve appropriate pricing in transmission, a performance-based model for setting the network companies' prices, called RIIO (Revenue = Incentives + Innovation + Outputs) has been established by the electricity regulator, Ofgem.

The United States—Some 500 companies own transmission grids in the country. Responsibility for operating the transmission networks is dispersed among widely divergent business models that can coexist under the transmission open-access regime established by the Federal Energy Regulatory Commission (FERC). Overall the grids are operated within a framework of about 130 control areas, which the FERC now calls “balancing authorities” (Willrich 2009).

RTO/ISOs provide transmission service for about two-thirds of America's electricity consumers in the Northeast, mid-Atlantic, Midwest, and California. Transmission service in the Northwest and Southeast is provided by investor-owned utilities. An RTO/ISO designs and administers within its balancing authority several types of auction markets, including day-ahead and real-time wholesale spot markets, and forward markets for financial transmission rights. These markets are characterized by transparent prices that support workably competitive market outcomes. Importantly, both the RTO and ISOs report evidence of possible manipulative behavior to the FERC. The North American Electric Reliability Corporation (NERC) puts in place reliability standards and enforces them.

RTO/ISO staff and stakeholders reach consensus on planning assumptions, and identify locations where transmission projects may improve reliability and/or relieve congestion, provide economic benefits, and help meet renewable portfolio standard goals. Depending on project size, the management or RTO/ISO board approves projects. The FERC encourages RTO/ISOs to participate in regional planning efforts. Respective state public utility commissions and the FERC (in the case of investor-owned utilities) approve cost recovery for transmission investments.

Sources: AER 2009; BETTA 2011; EC 2007; IEA 2012; Willrich 2009.

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Maharashtra State Electricity Transmission Company's Strategic Alliance Model

The Maharashtra State Electricity Transmission Company (MSETCL), unbundled from the Maharashtra State Electricity Board in 2005, is responsible for transmission and load dispatch in the state. The utility is the largest state transmission company in India by asset base. Maharashtra is one of India's most industrialized states, but has been suffering from massive transmission shortages and growing power outages. In response, the government developed an ambitious plan to invest \$5.5 billion over four years to improve transmission capacity by 120 percent. In 2006, the MSETCL sought financial and technical assistance from the World Bank to improve its institutional and implementation capacity in furtherance of its objectives.

By 2007, after extensive consultation—among employees, customers (mainly the distribution companies), equipment and services suppliers, state government, and the state power regulatory authority—a consensus was reached to adopt a public-private partnership-based approach. This “strategic alliance” model entailed designing an optimal bidding strategy for selecting a private partner for this priority program and developing a risk-sharing contractual framework to attract large and technically competent vendors on a “win-win” platform. The idea was that both the MSETCL and the chosen strategic alliance partner would benefit from more efficient and cost-effective project implementation resulting from a faster, less cumbersome tender process, and technical and project management skills would be fostered within the company.

This strategic alliance approach—a first for India—allowed for innovative risk-sharing between the MSETCL and its contractors by building performance-based conditions into the contracts, such as incentives for early completion, implementation of quality assurance mechanisms, and contractual payments linked to physical progress of works rather than to supply of equipment. Another critical innovation was that instead of inviting separate bids

for more than 250 contracts in line with traditional practice, the projects were bundled into four packages based on geographic contiguity and required timelines for completion. This bundling greatly streamlined the procurement process.

Adopting this partnership and risk-sharing approach required a fundamental cultural shift at the MSETCL, which had grown accustomed to executing all investments either in house or through a rather adversarial, top-down relationship with vendors. The new approach allowed the MSETCL to quickly attract and secure large and technically competent engineering procurement and construction partners to implement the expansion. In May 2009 strategic alliance contracts worth around \$1.5 billion were awarded to globally reputable transmission vendors, which are expected to save the MSETCL \$100 million compared with internal cost estimates.

Following the success of the strategic alliance framework, the MSETCL's next key challenge was to ensure that it had sufficient capacity to adequately supervise all its projects and contractors. The MSETCL thus focused on implementing a detailed project monitoring and review process and a well-defined strategic communication framework. These initiatives served to strengthen its institutional capacity for managing public-private contracts, its human resources approach, and sustainable change-management practices. Major changes have been executed in business processes and hierarchies within the organization, current roles have been realigned, and new positions have been created.

More specifically, instead of separate departments working on different phases of project design and implementation, integrated project teams with representation from different functional areas were operationalized. In addition, revamped reporting—by key results area/key performance indicator—and effective performance appraisal systems created a system of transparency and accountability. After a year of implementation and continued management support, positive change permeated the organization, prompting enthusiasm among staff. There is now regular proactive dialogue in review meetings on constraints faced in achieving key results areas, and on how to overcome them.

The MSETCL's transition from a traditional state government department to an efficient and commercial entity is steadily being achieved. Indeed, the MSETCL has become a model for other Indian utilities. In addition to maintaining healthy profits (Rs 3,290 million [\$70 million] in 2011), it has maintained high technical performance in line with international standards. In 2011 it realized systems availability of 99.62 percent for heating, ventilation, and air conditioning and 97.62 percent for high-voltage, direct current systems, and transmission loss of only 4.31 percent while wheeling a high of 102,076 million units of energy during the year. Since unbundling, annual transmission and distribution losses declined from more than 32 percent in 2006 to 23 percent in 2011.

Source: PPIAF 2012.

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International Experience in Private Sector Participation in Transmission and Distribution

Private sector participation (PSP) in transmission and distribution has been pursued by developed and developing countries as a means of addressing critical challenges in the power sector generally with one or more of the four overlapping objectives: introduce competition; attract fresh capital; improve financial and operational performance; and depoliticize the sector and reduce government influence. Several countries such as the United Kingdom and those in Latin America during the 1980s and 1990s pursued power sector reforms as part of a larger economy-wide liberalization effort in response to economic crises.

Three models of PSP have generally been followed for transmission: divestiture (the most common) was used in the 1980s in Latin American countries that followed the Chilean model, such as Argentina, El Salvador, and Peru; leasing contracts, which are relatively rare although employed by Brazil and the Philippines and in some Sub-Saharan countries like Kenya, Rwanda, Tanzania, and Uganda; and build-own-operate-transfer contract models in Peru. Turkey decided not to privatize transmission but only focus on privatization of distribution. As a result, it has an integrated transmission model where ownership and operation is under the responsibility of a single transmission company.

There is a full spectrum of options for PSP in distribution with models ranging from full to partial privatization. Some of the models adopted by different countries are divestiture (Chile, Peru, and the United Kingdom); management contracts; right to operate and investment management contracts with specific electric cooperatives (the Philippines); concession contracts (Brazil); contracts for transfer of operating rights (Turkey); and distribution franchises (India).

Selected Country Experiences

Germany—Europe’s largest power market, Germany’s transmission network is connected to nine neighboring countries. Historically, the market was run by a cartel dominated by four companies with legally enforced monopoly on service area through demarcation contracts. Germany began implementing the European Union Directive with its Energy Act of 1998, but it was not until the creation of the Bundesnetzagentur (sector regulator) in 2005 that ordinances for opening distribution networks and terms and conditions for these were passed. In 2009 Germany adopted incentive- rather than cost-based regulation to spur efficiency.

The United States—PSP has had a long history starting with municipal franchises (concession or license) with monopoly over assigned service areas. Regulation was also developed at the state (not national) level, which continued in largely the same form until major developments occurred in the 1980s, focusing on increased trading rather than on changes in ownership or structure, as the construction of high-voltage networks came to be recognized as a means of enabling commerce. Sophisticated means of transmission pricing and wholesale market energy trading were developed, which became salient characteristics of the industry.

The United Kingdom—After the recession of the 1980s, the United Kingdom viewed privatization and liberalization as a way to reduce public spending and the national debt, and to improve sector efficiency. As a result, the UK became the second country after Chile to pursue PSP in power sector networks. Unbundling and the creation of the Electricity Pool enabled competition in the non-monopolistic segments (generation and retail). This was complemented by the application of an incentive or performance-based regulation (PBR) for pricing and service quality of the natural monopolies of electricity transmission and distribution. The state monopolies went through several stages of takeover and merger during the 1990s. Currently, there are 12 regional distribution networks in England and Wales run by seven companies and one company for transmission, National Grid UK. Transmission and distribution in Scotland are run by two vertically integrated firms (Pond 2006). Reforms have largely been a success, resulting in a healthy competitive market with lower overall tariffs and improved operational and technical performance compared with pre-reform days.

Australia—The restructuring of the electricity industry in Australia was initiated in 1991, and by 1998 a National Electricity Market had developed to lower electricity prices through competition by creating a more flexible and cost-efficient industry. Although a “national approach” was adopted for introducing competition and operating a nationwide market, states had significant independence in their PSP approach. Victoria led the way, closely following the UK model—vertically unbundling and privatizing the state utility and creating a state power sector regulator. Western Australia separated out supply but left generation as one business; New South Wales unbundled but kept the utilities under government ownership; and South Australia privatized electricity assets via long-term lease arrangements.

Chile—Chile is widely regarded as the world's pioneer in restructuring and privatizing electricity markets. Reforms resulted in almost 100 percent private ownership of generation, transmission, and distribution, and served as a model for other countries in Latin America. Transmission and distribution are each a regulated monopoly, and distribution companies within concession areas serve both regulated and nonregulated customers. The power market is one of the best performing in the world, with high employee efficiency, quality of service, and consistently low distribution losses (at 5–6 percent, better than in most developed countries). The progress is best illustrated by Chilectra, Chile's largest distribution company (discom): from 1987 to 2011, its sale of power almost quadrupled to 13,697 GWh, and the number of consumers increased 70 percent to 1.6 million, all the while reducing the workforce from 2,587 to 712 employees.

Brazil—Power sector reforms were initiated in the 1990s when economic difficulties and high inflation severely curtailed the government's ability to continue operating state-run businesses. In 1997, around half the transmission and distribution utilities were transferred to new private owners on the basis of 30-year concessions awarded through public auctions run by Agência Nacional de Energia Elétrica (the national electricity regulator). While the first round of privatization improved performance, severe drought-related power shortages in 2000–01 led to a second round of reforms aimed at renewing private investment. This "New Model" introduced energy auctions as the main procurement mechanism for discoms to acquire electricity wholesale.¹ Reforms aimed to ensure fair tariffs by providing for tariff reviews whenever any taxes or legal charges were introduced after bidding. Post privatization, utilities have markedly reduced losses and improved quality of supply.

Peru—Following economic upheaval in the late 1980s, an independent power regulator was created in 1993. Over 1994–97, reform went smoothly and distribution assets in Lima and five provinces, as well as the national transmission system, were privatized. Thereafter the process slowed due to domestic and external factors (political resistance and economic spillovers from the Asian financial crisis). There were some setbacks: in 2001, four regional utilities covering 800,000 clients were taken back by the state after the failure of a local concessionaire to comply with its payment obligations. Severe drought-related power shortages forced a second round of reforms in 2006, encouraging PSP by strengthening planning and the pricing policy for generation and transmission. Despite improved performance, there has been vertical reintegration in the sector.

Argentina—The Electricity Law of 1992 unbundled state utilities, established a wholesale energy market, and created a sector regulator. Contracts were awarded for 99 years with price reviews every five years. However, the reforms were largely undone following the country's severe economic and political crisis in 2001. Extreme devaluation of the peso forced the government to violate the concession contracts it had signed by freezing tariffs, despite clear provisions on pricing. Even with economic recovery, tariffs continue to be propped up by government subsidies under discretionary and unclear rules.

This reform reversal has resulted in a widespread default on debt payments by energy companies and a loss of shareholder value. After drastic deterioration in service quality, the government has publicly expressed its plan to take back the distribution companies.

Turkey—Turkey transferred operating rights to the state-owned companies and regional companies operating its distribution systems, while assets remained state owned. To encourage competition, discoms were initially not allowed to sell more than 20 percent of the total amount of electricity supplied within their own regions. This limit was removed in 2006 and discoms were permitted to hold generation licenses and become self-suppliers. The transmission sector remains under a single public company, TEIAS, with an integrated model where both transmission grid ownership and operation is independent of supply and trading, which minimizes any tension between the system operator and grid owner, and promotes efficient maintenance and expansion.

The Philippines—Executive Order 215, issued in 1987, permitted the private sector to participate in power generation (FDC 2007). Deteriorating finances in the early 2000s forced reforms to increase PSP. The regulatory agency (the Electricity Regulatory Commission) was established in 2001 to oversee unbundling and privatization of the National Power Corporation (the state utility). The private sector is involved with municipality-owned utilities or electric cooperatives operated through investment management contracts. Joint ventures are also prevalent. The transmission company's (TransCo) assets were privatized in 2009. They are now run by the National Grid Corporation of the Philippines through 25-year concessions. The Electricity Regulatory Commission promulgated a performance-based regulatory framework, and the performance of the transmission sector has markedly improved since privatization.

Europe and Central Asia—Several countries launched power sector reform at the end of the 1990s, notably former Soviet republics such as Georgia, Moldova, Tajikistan, and Ukraine, to varying degrees. In Georgia, after unbundling and urgent rehabilitation of transmission and distribution infrastructure, the discoms were privatized. Ukraine's power sector was unbundled and partly liberalized, and the distribution segment privatized (out of 27 regional discoms, only 14 are majority state owned).

Key Findings

The PSP experience in transmission and distribution in both developing and developed countries has provided many lessons. Across the board, PSP has consistently increased inflows of private capital; improved technical, operational, and financial performance; and motivated the strengthening of the regulatory framework of the country's power sector.

- PSP has played a key role in attracting fresh capital. In Peru, over 1994–2010, the private sector accounted for 87 percent of all investment in transmission and 56 percent of distribution expansion. In Turkey, estimates suggest over

\$5.7 billion in government revenue has been raised from privatization. Private capital has also been used to fund improvements in network operation and maintenance in countries like Brazil and Chile.

- PSP has improved financial and operational performance of transmission and distribution sectors. Losses came down and employee efficiency went up. Quality of service also improved with reliable power and fewer outages. New contracting procedures, network modernization, better customer relationships, and corporate management were fueled by the private sector.
- In successful PSP models in transmission and distribution, private companies act as effective implementers of programs that are systematically planned, designed, and funded by the relevant government agencies. As Brazil, Chile, and Peru discovered during the first phase of reform, even the best-performing private discoms do not initiate service expansion without specific incentives. The private sector does not address issues of energy security either, which is necessary for large-scale and long-term integrated planning.
- Vertical and horizontal reintegration of assets after reform is a concern, as seen in several Latin American countries (Chile, El Salvador, and Peru) and Turkey, where creeping monopolization hampered early progress and made market entry for new players nearly impossible. Clear policies are needed to halt this trend.

The key to attract PSP is to reduce risk and improve the financial viability of the sector:

- PSP requires a sound and transparent policy and regulatory framework/environment and a strong and independent regulatory agency. This can help to improve the credibility of the government and sector by reducing uncertainty, such as political risk (as seen in Argentina), which is imperative to attract private investors.
- Distribution projects tend to be riskier than generation or transmission projects, with threats of contract cancellations and major disputes. Worldwide, 13 percent of more than 250 contracts involving distribution signed in 1990–2005 are no longer operational, almost twice the rate of generation projects.
- Preventing tariff volatility and charging cost-reflective tariffs to end users is critical for promoting high-quality service and for service providers to achieve reasonable profits. Introduction of PBR² and multiyear reviews has been very effective in Latin America (Argentina, Chile, Columbia, El Salvador, Peru, and Brazil) in helping allay investors' reservations.

Sources: Bowman and McKay 2001; FDC 2007; Pond 2006; Woolf and others 2010; ESMAP (forthcoming).

Notes

1. The New Model is being discussed and implemented in developed countries such as the United Kingdom and Australia for developing smart grids.
2. Under traditional cost-of-service regulation, utilities are allowed to recover prudently incurred costs plus a return. This requires frequent regulatory reviews and provides little incentive to increase service offerings or cut costs. Under PBR, price or revenue is capped, providing utilities with the incentive to improve efficiency and reduce costs to improve profit margins. PBR is a more light-handed form of regulation, resulting in reduced costs of regulation, reduced cost of power owing to sharing of utility cost reductions between utilities and consumers, and improved risk allocation between utilities and consumers. Most PBR schemes institute a revenue or price cap adjusted annually to account for input price increases offset by productivity improvements to ensure that customers share in any benefits derived by the utility (Bowman and McKay 2001).

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International Experience in Open Access

Open access (OA) to the power grid is an essential element in introducing competition to electricity markets and thus contributing to their efficiency. The competition permitted by OA allows for multiple and flexible power supply contracts that take advantage of load and time diversity and contribute to more efficient operation, thus potentially reducing tariffs and improving the quality of power supply.

Opening up access to the grid can be seen as a multilayered process: passing OA laws and establishing regulatory agencies constitute just the first step. Countries need to go beyond that by fostering a vibrant marketplace that is sophisticated, efficient, and supported by specification of terms and conditions of access, including pricing arrangements. Countries that have fully enabled OA have experienced an improved competitive environment and better sector performance. Greater transparency has attracted new investments in generation and network development, and countries like Brazil, Peru, and Turkey have seen impressive growth in the wholesale market.

Country Experiences

The United States—Unleashing competition to bring down costs was the main rationale for the U.S. power industry and regulators to embrace the concept of OA. The United States has increasingly relied on OA in its gradual progression toward wider competition, starting with the introduction of a competitive wholesale power market. During the 1980s, the Federal Energy Regulatory Commission (FERC) began to move from traditional cost-of-service rate-making at the wholesale generation level, toward allowing prices to be set by competitive market forces, culminating in the Electricity Policy Act (EPACT) of 1992, which mandated transmission OA. Open access at the retail level varies by state—roughly half the states have retail third-party competition and retail choice.

Canada—Because much of Canada's grid is integrated with that of the United States and many Canadian utilities sell to the United States, the FERC policy of OA has significant influence in Canada. Many of the utilities in Canada are still owned by provincial and local governments, and market structures vary from one province to another. Models include separation of generation and transmission from distribution and retail supply; an open market with retail choice; open wholesale markets; and some forms of competition in generation along with retail choice. The National Energy Board (Canada's national energy regulator) works with a number of provincial and federal agencies to improve the regulatory process.

Brazil—The electricity market model is one of the more advanced with respect to enabling OA, with a detailed and explicit legal framework for OA to transmission and distribution and creation of regulatory institutions. However, the absence of effective and transparent price signals for ancillary services, congestion, and demand response has hampered achievement of full OA and the development of an efficient and competitive power market.

Chile—The enactment of DFL No. 1 in 1982 aimed to make generation competitive and enable OA in transmission, while distribution was to remain a natural monopoly. A market was set up between generation and distribution companies (discoms) for small consumers, and large consumers were enabled to engage in supply contracts with generators or discoms. The Chilean wholesale electricity market comprises a spot market and a contracts market. Dispatch and prices are based on an economic merit order. Prices take account of transmission constraints, so generators directly bear those costs (Pollitt 2004).

Germany—Historically, the German electricity sector functioned as a cartel with biased rules for network access. The sector was restructured in 1996 and nondiscriminatory network access was mandated in 1998. Reforms continued with the formation of the Bundesnetzagentur (sector regulator) in 2005, and ordinances requiring the opening of distribution networks and specifying the general terms and conditions for this were passed. In 2009 Germany adopted incentive-based regulation, rather than cost-based regulation, to spur efficiency. The electricity market comprises a futures market, day-ahead (spot) market, and intraday market (organized by the European Energy Exchange and European Power Exchange) and reserve markets (operated by the transmission system operators).

Australia—The National Electricity Market (NEM) began in 1998, with national prices set by a National Electricity Code Manager while the Australian Competition and Consumer Commission set transmission prices. The Minister for Energy has review powers over certain Commission decisions. Australia has a gross pool system that suppliers bid into. It does not have a nodal pricing system and there are high variations in regional spot prices due to loss factors for transmission and capacity. The development of the NEM has accommodated substantial load growth, while absorbing several thousand megawatts of new merchant plant of various types and sizes. Reasons for the success of the NEM include careful specification and description of network limitations, resulting in a general

increase in network utilization; consistent application of standards for connection and access; and transparent governance strictly adhering to the National Electricity Code and National Electricity Law.

Peru—OA to transmission has been particularly instrumental in the growth of the wholesale energy market, now accounting for almost half the country's electricity consumption, and attracting major investments in power generation. Formerly isolated self-generators have joined the market and have reacted positively to the government's call for building surplus capacity on their sites. A second wave of reform in 2006 highlighted the importance of government leadership in system-expansion planning and fostering competition. A notable element missing from the current model is a provision for independent energy trading intermediaries.

Turkey—OA policy and an active wholesale market led to sharp growth in installed capacity in 2003–11, with private investment accounting for 71 percent of the total increase. Turkey has pursued OA for wholesale and retail consumers alike. The retail threshold, initially set at 9 GWh a year, has consistently been reduced over the past decade. Turkey shows steady progress through the initial institutional and market design phases toward some of the elements of a full OA regime, including market-based wholesale price setting and regulatory provisions for pricing ancillary services.

India—Despite strong emphasis on OA in the Electricity Act of 2003, OA is still poorly implemented, with many problems arising at the distribution level particularly, leading to disincentives and conflicts of interest. First, distribution has not been unbundled from retail, and most states do not have an independent state load dispatch center (SLDC), but one that operates under the transmission company. SLDCs can be biased and resist OA by delaying applications, or deny rights to sell to a third party on technical grounds. States such as Karnataka, Maharashtra, and Tamil Nadu have also invoked Section 11 of the Electricity Act, restricting export of power outside the state. High charges are seriously deterring OA, including the contentious cross-subsidy surcharge (especially high in Punjab, Tamil Nadu, and West Bengal), which is imposed on consumers who trade the discom's retail sale service for those of an alternative supplier. While there is a significant volume of wholesale market transactions through power exchanges, a large part of this is accounted for by own-use or captive generation.

Key Considerations in Designing OA

Finding a suitable model. There is no established rulebook for implementing OA, as both the starting conditions and the political preferences of every country differ. Countries can envisage a minimalist approach by simply establishing legal rights, or can pursue more sophisticated models aiming to put price signals to work and remove arbitrary influences from the marketplace.

Sequencing wholesale and retail OA. The experience of countries with the most open and competitive power systems was to grant OA to the grid starting with the largest market participants and progressively lowering the size threshold of

players eligible to participate; reforms also started with transmission (wholesale) OA and went on to distribution (retail) OA. Retail OA, especially access to distribution grids, poses more challenges, requiring aggressive policy and price signals to incentivize the switch to an alternative supplier.

Unbundling and revenue separation. Before reform, many developing countries had integrated generation and transmission activities (the transmission cost was embedded in the price of energy sold). An effective OA regime requires a clear focus on the provision of network services as a distinct area of business operations, best achieved by unbundling transmission from generation and prohibiting transmission from association with other energy suppliers or traders.

Implementation Issues

Transmission incentives. When the transmission operation receives revenues specific only to provision of grid service, it has an incentive to improve the service, including maximizing throughput. To enhance OA transparency, a real-time website that monitors transmission grid utilization, capacity, and ancillary services should be provided.

Distribution incentives. Discoms should be neutral to energy sales revenues that they enable other parties to receive. Even when energy sales revenues belong to another party (generator, retail supplier), a discom is interested in maximizing its throughput—similar to the case of a transmission owner/operator. The discom's close interface with the end user can be misused to maximize throughput at the expense of socially desirable objectives, such as conservation or demand-side efficiency. Therefore, it is recommended that discom revenues be decoupled from throughput by revenue capping, where the regulator sets a total revenue requirement for the company for a certain period and tariffs are set to attain it. Tariffs can later be adjusted to meet any shortfall.

Default service obligation. In practice, it is difficult to achieve a complete unbundling of the distribution from retail business due to the default (or last-resort) service obligation of the distribution company. Therefore, even under a distribution OA regime, a discom will typically have a double license. To maintain competitive pressure on the default service provider, distributors should be obliged to bid out the last-resort supplier obligation on a parceled, periodic basis.

Product differentiation. In retail access particularly, a more efficient market will emerge if players are given an opportunity to offer differentiated products other than the default product. This may include the energy service company offering a blend of demand-side services as well as energy; or offering a hedged product with a fixed price or, conversely, a variable, time-differentiated market-following price depending on the buyer's preferences.

Large industrial consumers. These consumers are logical candidates for connecting directly to the transmission grid. The policy decision is whether or not to compensate the discom for losing such consumers to OA. The recommended approach is to allow large customers to buy off the local grid but limit their ability to move freely between the regulated and deregulated markets due to the

additional system costs and supply disruption this might cause. In several U.S. states, for example, large customers may return to the regulated market only if they pay all the incremental costs incurred. In Brazil, customers must provide the distributor with five years notice of intent.

Smart grid technology. This technology should be deployed at major sites of large customers and all distributed generators. In retail access, attention should be paid to who owns and operates the metering and billing operations. This capability is designed to enhance market transparency and efficiency, but in some circumstances it can also be exploited to exercise market power.

Sources: Pollitt 2004; ESMAP 2013.

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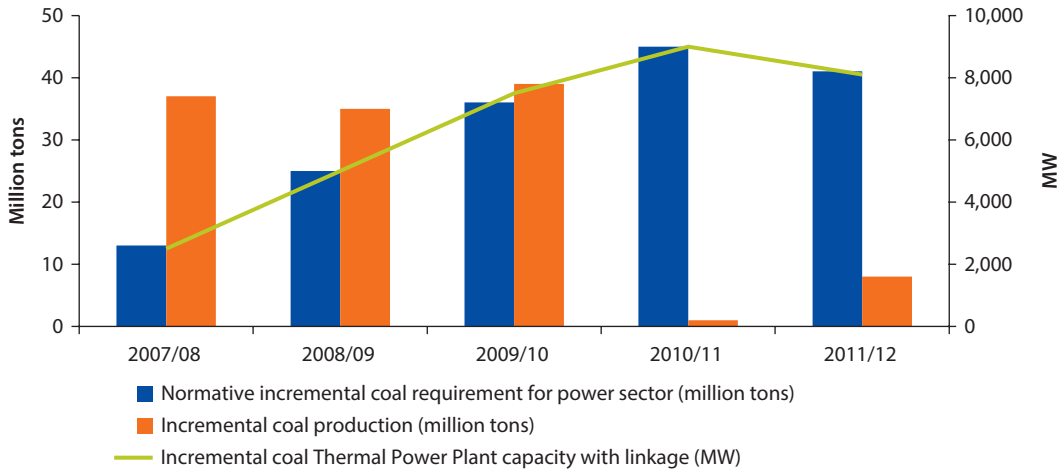
Coal Sector Challenges and the Power Sector

About 76 percent of the coal consumed in India is used by the power sector, and around 60 percent of the electricity generated comes from coal. The coal sector does not appear to have anticipated the rapid increase in commissioning of power plants, mainly led by the private sector, in the 11th Five-Year Plan. Large gaps between the coal requirement (for plants with coal linkages, which were commissioned during the plan period) and the actual increase in coal production (figure H.1), show that increases in production fell well short of demand. Such a discrepancy between incremental demand for coal by power plants with coal linkage (implying that they are known to Coal India) and actual production, particularly in 2010–12, points to a serious lack of coordination between the ministries concerned.

This is further illustrated by figure H.2, which shows that linkages were effectively approved for over 210 million tons per annum (mtpa) in 2009 and 2010 alone, even considering only a partial coal allocation of 3.4 million tons per gigawatt (GW) for power plants that requested the coal linkage (against the norm of 5 million tons per GW). In sharp contrast to the approved amount of 210 mtpa, figure H.2 shows that under the business-as-usual scenario, the total increase in production expected in the entire 12th Five-Year Plan is only 175 mtpa. If all the plants that have received these linkages (for 210 mtpa) are actually commissioned, it is unclear how they will be supplied with coal, or whether indeed some of them will become stranded assets from day one. It is likely that these linkages were used by private power developers to make their projects bankable; that is, cash-flow forecasts were based on them. The implications of granting these unrealistic linkages are now apparent.

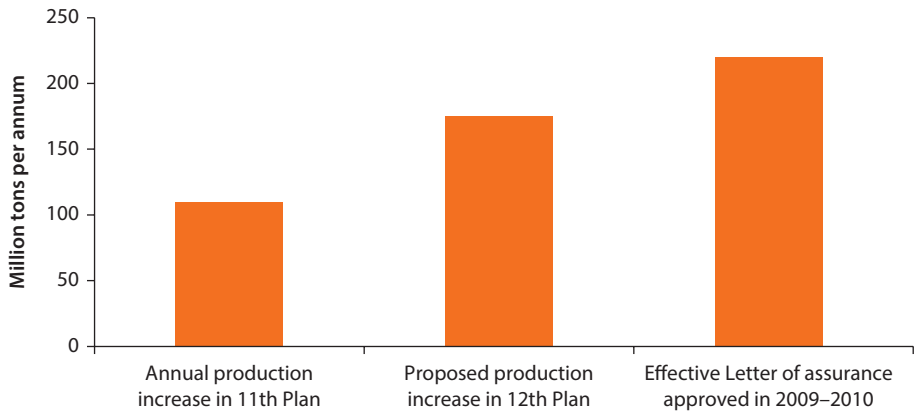
As of July 31, 2011, about 1,500 applications for linkages were pending with the government, including applications for about 600 GW of power plants (or 3,000 mtpa at the normative average of 5 million tons per GW), and a further 650 mtpa for cement and sponge iron plants. Clearly such huge pent-up demand cannot be satisfied, and whatever allocation process is used, winners and losers

Figure H.1 Incremental Coal Requirement and Coal Production, 2007/08–2011/12



Sources: Coal Controller’s Organization 2012; Ministry of Power 2007.
 Note: MW = megawatt.

Figure H.2 Proposed Coal Production and Linkages Granted



Sources: Ministry of Coal 2011a, 2011b.

will emerge. If this process is not transparent and objective, it is likely to unduly benefit some individual private players at the cost of the national interest and the reputation of the sector (witness “Coal-gate” allegations that undue financial gains of about Rs 1.86 trillion (\$40 billion) have accrued to private sector recipients of discretionary and nontransparent allocations).

Increases in production require adequate coal exploration around 10 years in advance to establish mineable reserves. However, exploration in the 11th Five-Year Plan was actually less than what was accomplished in the 10th Five-Year Plan, and only about 70 percent of the target was achieved. Yet despite this, the target for the 12th Five-Year Plan remains very optimistic.

Obtaining all the requisite clearances for mining to proceed often takes years, for reasons such as involvement of multiple agencies, and delays in finalizing terms of reference or in conducting public hearings. More than 15 agencies potentially need to be involved at various stages of the clearance process, such as the Ministry of Environment and Forests, Coal Controller's Organization, and Ministry of Coal, as well as various state agencies such as the mining, revenue, and forest departments, the State Pollution Control Board, and the district authority. Thus it is not so much environmental clearance alone (as often claimed) as the multiplicity of agencies and lack of coordination among them that delays mine development. This is also illustrated by the relatively small increase in coal production from mines that have already been granted environmental clearance (table H.1): mines are expected to be productive about three years after such a grant, but despite clearances being granted for about 96 mtpa of production in 2007, the actual production increase three years later (2009–12) was only about 8 mtpa—just about 8 percent of the capacity granted.

The same holds for captive blocks, that is, those allocated to an entity which is then supposed to apply for a mining lease within three months from block allocation (and finish exploration in two years and three months from allocation). Normative guidelines from the Ministry of Coal state that a captive block is expected to be productive (extracting coal) in 3.0–4.5 years from allocation. However, though 109 coal blocks had been allocated before 2007, only 24 captive blocks had started production by 2010/11 (figure H.3). Of those not yet producing coal, only 24 block allocations have been cancelled so far, while 56 blocks were issued with “show cause” notices as late as May 2012, after captive blocks came into the media spotlight.

The upshot is that over time the number of captive blocks producing coal, as well as the quantity of coal from such blocks, has fallen well short of expectations, pointing to weak monitoring of captive block development by the Ministry of Coal.

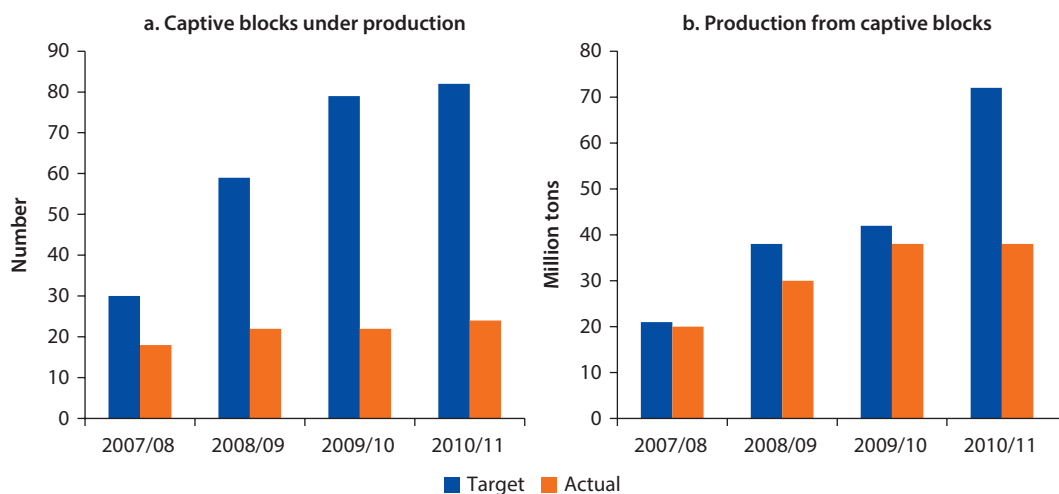
Table H.2 shows that India's coal production target for 2011/12 was lowered during the 11th Five-Year Plan, from 680 million tons to, ultimately, 554 million tons. But even the reduced target was not met and actual production fell short of the original target by about 21 percent. Surprisingly, despite widespread

Table H.1 Environmental Clearances and Increases in Production

Million tons per annum

<i>Company</i>	<i>Clearance granted in 2007</i>	<i>Increase in production, 2009–12</i>
Coal India	63.31	2.58
Singareni Collieries Company Limited	10.13	1.78
Other	22.56	1.59
Total	96.00	7.95

Source: Data from Ministry of Environment and Forests (Ministry of Coal 2011a).

Figure H.3 Captive Coal Blocks, Targets and Actual Production

Source: CAG 2012.

Table H.2 Coal Production, Targets and Actual, 2011/12

Million tons

Original 11th Plan target	680
11th Plan mid-term target	630
Final target	554
Actual production	540

Sources: Coal Controller's Organization 2012; Ministry of Coal 2011a; Planning Commission 2009.

knowledge that large additional power capacity was expected to come on line, the final target for coal production in 2011/12 was lower than the target of 572 million tons for 2010/11. This was likely because the coal sector was unprepared for so much power capacity coming on line, and it raises serious questions about sector planning, the process of awarding linkages, and coordination between ministries.

The inability of domestic coal production to keep pace with power capacity addition has contributed to a sharp increase in coal imports by the power sector. They went up from 10 million tons in 2007/08 to 45 million tons in 2011/12, despite the fact that installed thermal power capacity went up by only 50 percent.

Many coal consumers are not located at pit-heads and therefore increasing demand for coal also translates into increasing need for coal transport. Rail is the primary mode of coal transport. Given the expected increase in coal production and consumption, rail transport links and rolling stock for coal transport should have been augmented. Coal India officials cite the futility of increasing production of coal further without the ability to move it. Pit-head stocks are increasing

much faster than annual offtake. Inefficiencies are also seen in coal linkages, absent an attempt to optimize transportation. There are numerous examples in which either coal linkages or captive blocks have been assigned without consideration for transportation overheads.

Looking ahead, the coal sector's challenges require a comprehensive approach, involving numerous stakeholders, to address many of the issues identified above. An interministerial Apex Committee (coal, power, rail, environment and forests, iron and steel, industry, finance, the Prime Minister's Office, and the Planning Commission) should transparently consult with, and consider suggestions from, all stakeholders including coal producers, consumers, social and environmental activists, academics, coal-washing organizations, consultants, logistics organizations, and anyone else considering themselves interested parties. Agendas and minutes of these meetings and consultations should be in the public domain, and all reports prepared by committees on coal should also be disseminated widely, after incorporating feedback.

The root cause of the current problem is that much more coal has been promised to consumers than is realistically possible for Coal India to supply. All existing coal linkages will need to be reviewed and optimized to reduce coal transportation requirements. Linkages of end-use plants whose progress is unsatisfactory could be reassigned to different end users who have shown greater progress.

One of the options the government has been considering to address the downstream cost impact of imports is the use of pooled prices. In July 2012, Coal India reported plans to import up to 30 million tons of coal in order to meet rising domestic demand and to mitigate power shortages. However, as the imported coal price would be based on gross calorific value, following international trading practice, and Indian domestic coal pricing would be based on useful heat value, it can be assumed that a combined or pooled price would be higher than current domestic coal prices paid by thermal power plants.

In addition, coal imports and their delivery will require considerable logistical capability and planning:

- Coordinated transport arrangements for ports, rail, loading and unloading facilities, etc. are not in place—constraining imported coal movements—and true pooling may not be physically possible. Lessons learned from logistics problems with imported coal in 2012 should be carefully reviewed.
- Domestic coal raises similar logistical challenges due to uneven geographic allocation of India's own coal resources:
 - Most of India's reserves are in the East—Jharkhand, Orissa, and West Bengal. This region has 173.12 billion tons (62.7 percent) of reserves with 293 mines owned by Eastern Coalfield Ltd, Bharat Coking Coal Ltd, Central Coalfield Ltd, Mahanadi Coalfield Ltd and some private players. This region produced around 232.6 million tons in 2010–11.
 - In the Western region coal reserves are in Chhattisgarh, Madhya Pradesh, and Maharashtra. The region has 79 billion tons (28.6 percent) of reserves

- with 186 mines owned by Western Coalfield Ltd, South Eastern Coalfield Ltd, and others. It produced 223.6 million tons in 2010–11.
- The Southern region has 22.01 billion tons (8 percent) of reserves, mainly in Andhra Pradesh. It has 67 mines owned by Singareni Collieries Company Ltd and some others; the region produced 51.333 million tons in 2010–11.
 - While it seems difficult to pool coal in physical terms because of logistical challenges, it is much easier to pool in pricing terms (for example, the weighted average of import and domestic costs). However, the impacts are likely to be highly unequal. Those power generators—generally public—that have access to cheap domestic coal will suddenly face a hike in input costs. And those reliant on expensive, imported coal—generally private—will benefit from a lower average price.
 - Price pooling is a pure redistribution from the state sector (and eventually the consumer) in favor of private power producers.

International Experience with Coal for Power Generation

The organization of the coal-mining sector and its links to power generation vary widely among countries (table H.3). It ranges from a fully privatized coal and power sector where the market decides the demand, supply, and therefore pricing (as in Canada, the United Kingdom, and the United States); to a partially regulated power or coal sector with subsidized end-user prices of electricity (as in China, India, Indonesia, and South Africa); and all the way to a tightly regulated monopoly market of state-owned enterprises (as in Vietnam).

Lack of coordination between the power and coal sectors in many of these countries emanates from ineffective market organization, competition with export markets, transportation bottlenecks, and a feeble institutional setup that lacks regulatory oversight.

In countries rich in coal reserves like Australia, Indonesia, Poland, and South Africa, domestic power plants often have to compete with the coal export market. When the price of coal in the international market is high, coal companies tend to export good-quality coal while providing the power plants with lower-quality coal. In such situations, power plants have to find shorter-term coal contracts at higher spot prices that often increase the cost of electricity. To avoid that, the Indonesian government in 2009 came up with the “Domestic Market Obligation,” which makes it binding for coal companies to supply part of their production to the domestic market.

Similarly, a lack of coordination in planning for the coal sector in the face of increasing power demand leads to supply shortages, as seen in South Africa’s power crisis of 2008. As the production capacity of ESKOM (the state-owned power company) surpassed existing coal contracts, power shortages were imminent. Thus ESKOM launched a forum for government departments and enterprises to work together. A second initiative was the South African Coal Roadmap,

Table H.3 Coal Production, Market Structure, and Regulation: Some International Examples

Country	Coal produced (1,000 tons)	Coal consumed (1,000 tons)	Coal market structure	Power market structure	Coal market regulator	Transportation bottleneck	Country-specific remarks
Australia	402,237	133,650	Competitive: Dominated by 4 big companies	Competitive	Absent	Rail constraints in transporting coal to power sector and for export.	State-level regulations exist for the coal industry. Fragmented and dispersed authorities with limited intervention by central government.
Canada	67,114	43,025	Competitive: 8 publicly traded companies	Competitive	Federal Minerals and Metals Policy by Natural Resources Canada (NRCan) ensures competitiveness in mineral industry.	Coal is transported using rail and roads. No major bottlenecks.	Mineral resources in Canada are either provincially or federally owned. Every year NRCan publishes statistics on coal production, consumption, trade, the market, and prices.
China	3,418,766	3,501,294	Decentralized: Previously state owned and local mines administered by provincial authorities, and individually/ community-owned township and private mines	Partly deregulated: Dominated by 5 companies that emerged from former state power company	State Economic and Trade Commission (SETC) oversees the market. Industrial Management department of SETC coordinates the coal, rail, and electricity sectors.	Rail infrastructure is inadequate leading to accumulation of coal stockpiles at mines.	Power prices are regulated but coal prices are market based, generating tension between the power and coal sectors. The increasing gap between contracts with power plants and spot market prices, and reluctance of power producers to pay the market price makes coal producers hesitant to sign contracts with them.

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Table H.3 Coal Production, Market Structure, and Regulation: Some International Examples (continued)

Country	Coal produced (1,000 tons)	Coal consumed (1,000 tons)	Coal market structure	Power market structure	Coal market regulator	Transportation bottleneck	Country-specific remarks
Indonesia	360,336	59,716	Competitive—6 major producers, including state owned listed company PTBA, account for 75% of production	Regulated—State Electricity Company PT PLN	Ministry of Energy and Mineral Resources imposes a DMO (Domestic Market Obligation) on coal producers to provide a production plan and supply a share (updated annually) of total production to domestic market depending on demand.	Diesel-based trucks and barge inland transport system has relieved bottlenecks.	Although DMO has led to reliable coal supply for PLN, issues around supply shortage of specific coal ranks and non-payment by PLN are common. DMO affects Indonesia's coal export business.
Poland	139,289	146,235	Competitive but not entirely privatized: 6 major companies including 3 state-owned publicly traded companies	Competitive	Absent	Not an issue, except harsh winters. Law requires power plants to maintain three weeks' coal supply.	No formal planning exists for coal sector. Government prepares energy plan for 1–2 years, which indicates coal demand. Imports reduce risk of a supply gap.
South Africa	252,757	186,340	Competitive—5 large private companies dominate production. Also, many small miners.	Monopoly—state-owned power company, ESKOM	Absent	Recent shift to short term coal contracts with mines away from the power plant has led to increased dependency on road transport, thereby affecting road infrastructure.	Given the lack of an explicit coal policy and government inaction over ESKOM's difficulties with assuring long-term coal supply, ESKOM initiated a forum for government departments and enterprises to work together for a solution. The South African Coal Roadmap is another effort to get parties to work together on the issue.

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Table H.3 Coal Production, Market Structure, and Regulation: Some International Examples (continued)

Country	Coal produced (1,000 tons)	Coal consumed (1,000 tons)	Coal market structure	Power market structure	Coal market regulator	Transportation bottleneck	Country-specific remarks
United Kingdom	18,627	51,500	Competitive	Competitive	Absent	Coal is delivered by rail. Except for minor delays, no major bottlenecks. Coal companies have good relations with haulage companies.	The market decides on the supply of and demand for coal. Power companies have confidential commercial negotiations with coal-producing companies (in the United Kingdom and overseas). Assessment of reserves, production, transportation, and trade are matters for coal-mining companies and their customers. The government does not interfere in the commercial market but regulates health, safety, and environmental issues in mining.
United States	1,005,921	920,300	Competitive: 4 major companies produced 52% of coal (500 companies the balance)	Competitive	Absent	None major.	The market decides on the supply of and demand for coal. Power companies have commercial contracts with coal-producing companies.
Vietnam	44,493	27,728	Monopoly: State-owned Vietnam National Coal and Minerals Industries Group (VINACOMIN)	Moving into competitive generation market, but state-owned power company (EVP) has a monopoly.	Absent	Coal is generally transported by road; use of freight cars increases cost of coal in the market.	To meet growing power demand, VINACOMIN is expanding mining activities. The government assigned VINACOMIN to play a leading role in importing coal. The company is also constructing a port for coal transshipment.
World total	7,607,619	7,526,694	–	–	–	–	–

Sources: Eberhard 2011; Lucarelli 2010, 2011; Morse and He 2010; Suwala 2010.

which engages stakeholders to facilitate policy, planning, and strategy development in this sector.

Renewal and renegotiation of long-term contracts between power companies and the coal sector is another area of concern in many countries. Competition from the export market aside, this is also driven by regulated end-user prices of electricity and nonpayment of bills by monopsonist power companies. Since 2002, this has become a significant challenge for China. As the gap between term-contract coal prices and spot market prices widens, tension between coal producers and power generators has heightened. Coal producers have become increasingly reluctant to enter into contracts, fearing that they will be locked into prices that turn out too low, and key power producers are in turn reluctant to pay the market price.

Another sector that affects both the supply and pricing of coal to power plants is transport. For countries with mine-mouth power plants such as Australia, Poland, and South Africa, this transport constraint is insignificant. However, countries that depend on road and rail transportation of coal over long distances bear the impact of heavy vehicles that damage the transport infrastructure. Furthermore, in many cases, development of infrastructure is not aligned or coordinated with development of mining activities. In such situations, companies generally invest in their own transportation facilities (if permitted by law) or tend to develop good relations with freight companies, as seen in the United Kingdom. The Industrial Management department of the State Economic and Trade Commission in China is a good example of an institutional setup that coordinates the coal, rail, and electricity sectors.

Countries with competitive coal and power markets have fewer challenges around coordinating the coal and power sectors, as contracts with domestic or overseas coal companies are commercially driven, and require less government involvement. In almost all the major coal-intensive developed economies (except Canada), there is no specific regulatory body to oversee market performance and prevent abuse of market power. However, as mining is a capital-intensive business, only a handful of companies in Australia, Poland, South Africa, the United Kingdom, and the United States now dominate the market, increasing concerns about the lack of a truly competitive market.

Although regulatory oversight of market performance is lacking in developed countries, there is strong regulatory oversight on health, safety, and environmental issues for coal mining. The Coal Authority of the United Kingdom, Natural Resources Canada, and the Environmental Protection Agency in the United States are examples.

Sources: Eberhard 2011; Lucarelli 2010, 2011; Morse and He 2010; Prayas Energy Group 2013; Suwala 2010.

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Best Practices in Electricity Theft Reduction

Electricity theft at the distribution end is fairly common in India. Though theft is not explicitly measured, aggregate technical and commercial (AT&C) losses of over 26 percent in 2011 suggest high levels of theft. Thieves employ a variety of methods, including tampering with meters and seals, bypassing meters, and damaging or removing meters; hooking directly onto bare wires or tapping underground cables; or tapping terminals of overhead lines on the low-voltage side of the transformer. First generation electronic meters are susceptible to interference from electrostatic discharges or magnetic disturbances close by—and thieves know this. In addition, theft can take the form of billing “irregularities” (often with the connivance of meter readers) and unpaid power bills.

Electricity theft can be tackled through technical and nontechnical means. Technical solutions used in India include the following:

- Implementing high-voltage distribution systems—that is, bringing high-voltage supply as close as possible to point of use. This reduces technical losses, because the higher voltage means there is less current flowing for the same amount of power supplied, and commercial losses as well, because high-tension voltage cannot be directly used by households and small commercial establishments (and it is more hazardous and complex to tap into a high-tension line).
- Covering and bundling low-voltage lines (aerial bunched cables), which makes tapping difficult.
- Using closed distribution boxes for low-voltage lines at the pole end so that they cannot be tapped.
- Installing meters outside establishments (such as homes and buildings) on service poles, which makes tampering visible, and, if theft is detected, painting the meter black to indicate theft to the community.
- Removing the human interface from meter reading by using technologies such as automated meter reading (AMR) and carrying out real-time energy audits

using software. AMR, which is increasingly used for large consumers (industrial, commercial, and some domestic) has the advantage of generating real-time data on consumption that utilities analyze for inconsistencies or sudden changes, which may indicate interference with the meter, prompting timely investigation and corroboration through site visits.

- Installing second-generation meters, which are shielded from interference.¹

Nontechnical theft prevention measures include public outreach to increase awareness of the importance of paying for electricity, better consumer service (on-the-spot billing and collection, establishment of 24-hour call centers to handle complaints), and legal and regulatory steps.

Similar measures have been adopted in other theft-prone areas of the world (including Brazil and Nigeria). In Brazil, initial steps included customer indexation (by geographic location and electrical feeder), regular communication with customers, establishment of service centers (with key performance indicators that include the average time taken to assist customers), and AMR and automated alarm signals when nontechnical losses are detected. In addition, companies like CEMIG in the state of Minas Gerais use information technology (IT) to trigger an inspection when consumption inconsistencies are spotted, when complaints are received (both internal and external), and when data mining indicates losses beyond the norm. AMPLA, a private company in Rio de Janeiro state that distributes electricity in slums dominated by drug traffickers, has adopted AMR for all its residential consumers. As well as bunching low-voltage cables, it uses 10-meter electric utility poles that are hard to climb and ensures that distribution boxes and connections are difficult to reach. Every medium- and low-voltage transformer has a meter, and there are relatively few customers per transformer, making it rather easy to pinpoint and address problems, including theft. These measures led to a 44 percent decline in annual supply interruptions between 2003 and 2004. For large consumers and corporates, moreover, meters are at a distance from the user's premises; multiple "sub"-meters are used to disaggregate the load and enable easier location of the source of any inconsistencies; telemetry is used; and motion detectors/sensors are incorporated into the metering infrastructure.²

The Nigerian utility, NEPA, has followed an initiative known as CREST (Commercial Reorientation of the Electricity Sector: Toolkit) to reduce losses. Ring-fenced "clusters" serving around 50,000 consumers are demarcated and comprise a single network served by a 33/11 kilovolt (kV) substation with about six 11 kV feeders facilitating energy audits (input and use) and presenting a manageable business proposition for outsourcing various activities. CREST involves the following key actions: metering of all customers; a regular increase in the value of the estimated bill until meters have been put in place; electronic and spot-billing of all customers; energy audit of distribution feeders; remote reading of major customers to eliminate fraud in meter reading; high-voltage distribution systems to reduce theft and losses; internet-based customer records

for greater transparency and information; customer service centers for improving utility-customer interface; outsourced rapid response mobile customer service units; outsourced retail areas such as housing estates, markets, and industrial areas on a bulk-metering basis to contain illegal connections, improve service, and increase revenues; and a focus on collecting government receivables.

In India, Tata Power Delhi Distribution Ltd has brought down its AT&C losses from 53 percent to 11 percent over 10 years with various measures, including universal metering in the service area using tamper-resistant electronic meters, often encased in boxes; AMR for high-revenue customers; data analysis to detect theft; high-voltage distribution systems and replacement of bare overhead lines with aerial bunched cables; periodic energy audits of feeders from power-import points to distribution transformers to identify leaks and prioritize actions in high-loss areas; advanced IT applications and process reengineering (enterprise resource planning, Supervisory Control and Data Acquisition, geographic information system mapping, billing and customer relationship management, etc.) to improve commercial processes; and fast-track of settlement of theft cases through public hearings and forums.

Several other Indian states have also been quite successful in reducing electricity losses, partly due to the implementation of theft-prevention measures, including IT and other technical solutions. Of the top 10 AT&C loss-cutting states,³ seven have brought in technical interventions similar to those used by Tata Power Delhi Distribution Ltd and other utilities in Delhi, and five have improved their billing processes using IT. Several states have adopted feeder segregation. Some states such as Haryana have tried nontechnical approaches such as creating incentives for consumers and employees to report theft, but these have shown limited success.

Twenty-two of India's 29 states have received state government support in the form of special courts for prosecuting electricity theft. These courts have expedited processing of cases of theft and recovery of penalties, and have been relatively active. In Madhya Pradesh, for example, they have solved over 25,000 cases since they were set up in 2010 (many of these cases were pending a decision at the time). Evidence is not yet available as to whether the courts have led to a decrease in theft.

Indian states have also established special police stations for handling theft, though the exigencies of maintaining law and order mean that this is often simply in theory. In many states (including Rajasthan and Andhra Pradesh), police stations are partly funded by discoms. In Rajasthan, human resources are deputed from the police department. Haryana has adopted electronic filing of complaints (about theft) by the utility to the police stations. Haryana has also significantly stepped up vigilance activities by setting and notifying targets for checking and recovery of dues and maintaining an electronic record of such activities. In other states, the special police stations have enabled the detection of a large amount (by value) of electricity theft, though the utilities have only been able to collect about half the penalty amount assessed. For example, in Rajasthan in 2010, Rs 949 million (\$20 million) was assessed for electricity theft by the utilities'

vigilance wings, but only Rs 461 million (\$9.9 million) was received by the utility; the situation was similar in Andhra Pradesh in 2008 and 2009.

Theft prevention support can also come from the regulator. For example, the regulator in Madhya Pradesh took *suo motu* action to put in place a procedure for provisional billing in extreme cases of electricity theft. Regulators in Delhi and Gujarat have issued regulations on assessing the size of energy theft, including for calculating the penalty amount. This has increased transparency and consistency of treatment of energy theft.

That said, as of April 2013, the four highest-ranking states in terms of reported numbers of cases of theft over the past four years were Madhya Pradesh, Haryana, Uttar Pradesh, and Delhi.⁴

Notes

1. Since the installed base of meters cannot be replaced overnight, this solution is not easy. To stay ahead, in fact, some utilities, including Tata Power Delhi Distribution Ltd, monitor the technologies used in meter tampering, which lets them revise the meters' manufacturing specifications.
2. Informal presentation (2010) of findings from a staff technical study tour of Brazilian power distribution companies.
3. By percentage reduction in 2003–11 these were Delhi, Kerala, Maharashtra, Gujarat, Rajasthan, Punjab, Karnataka, Tripura, Andhra Pradesh, and Nagaland.
4. The Ministry of Power, cited in *India Today*, April 1, 2013. Delhi is striking in that theft is completely in the domestic consumer category. In the other states theft is also prevalent among industry, commercial, and agricultural consumers.

Reference

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Regulatory Assets: The Delhi Case

In 2002 the Delhi Vidyut Board was unbundled into three (privately owned) distribution companies (discoms), a transmission company, a generation company, and a holding company that held most of the Board's pre-privatization liabilities. A five-year transition period was announced, in which all discoms would provide electricity to their consumers at the same rates, and bring down aggregate technical and commercial losses by 17 percent. During the period all discoms had to buy power from the transmission utility, Delhi Transmission Company Ltd, at subsidized rates and sell it to consumers at a rate determined by the Delhi Electricity Regulatory Commission (DERC). After five years, the subsidy was to be withdrawn and discom tariffs would be set by the DERC based on the utility's cost of service. The pricing mechanism, as worked out by the DERC, is based on the annual revenue requirement, which includes a 16 percent post-tax return on equity as assured profit.

Once the regulator has accepted the expenses leading to an agreed annual revenue requirement, there is an implied tariff hike to be borne by consumers. At this point, the DERC may exercise discretion to create a so-called "regulatory asset": if the regulator recognizes that a discom needs to be paid Rs 100 (\$2) but feels this will burden consumers who can pay just Rs 60 (\$1.20), Rs 40 (\$0.80) is classified by the regulator as a "regulatory asset," which is an outstanding receivable owed to the discoms, on which 13–14 percent interest will be paid the following year, as a carrying cost. Simply put, regulatory assets are dues that have not been paid to the discoms and can be recovered from consumers in the future by way of tariffs.

As of 2013, the regulatory assets of the three Delhi discoms stand at close to Rs 70 billion (\$1.5 billion) with the interest on the principal mounting. While the Appellate Tribunal for Electricity has said the carrying cost of regulatory assets should be paid to utilities every year in order to avoid cash-flow problems,¹ regulatory assets continue to pile up and utilities are unlikely to be able to retire them in the requisite three years. Three further problems are emerging with regulatory assets:

- Delays in "truing up" add up to the size of the regulatory assets—retail tariffs are always awarded at the start of the year on the basis of the discom's expected

- operating costs, but if the costs and revenues are different from what is projected, these additional gaps are fixed by “truing up” the following year.
- In several cases, to keep initial tariffs low, regulators have also been known to assign lower power purchase costs than the figures used by discoms to project their revenue requirements at the beginning of the year. When the “truing up” takes place after a year or two, there is a sudden swelling in the regulatory asset base.
 - Due to cash-flow constraints, discoms have ended up borrowing at high interest rates to finance power purchases. If their regulatory assets are not liquidated soon, the interest burden will continue to mount and their financial positions become untenable, with an increasingly remote chance of recovering the full amount due since this would require unrealistically high tariff hikes to be imposed on end users.² Consumers are now fighting very frequent tariff hikes and demanding greater transparency. They are also seeking to hold the regulator accountable for how it has been assessing “eligible expenditures” within the tariff petitions submitted by the discoms. Tariffs have reportedly increased by 65 percent since privatization, whereas costs of power purchase have increased by 300 percent.

The regulatory asset problem is not confined to Delhi. Nationwide it is estimated that regulatory assets have reached over Rs 700 billion (\$15 billion) and that just the interest cost adds up to around Rs 95 billion (\$2 billion) a year. Tamil Nadu has seen its regulatory assets swell to nearly Rs 200 billion (\$4.3 billion) from Rs 79 billion (\$1.7 billion) in 2010–11. In Haryana, regulatory assets have nearly doubled to Rs 13 billion (\$0.03 billion) from Rs 7.24 billion (\$0.16 billion) in 2009–10. Regulatory assets in West Bengal have increased to Rs 21 billion (\$0.45 billion) in 2012/13 from Rs 1.57 billion (\$433 million) in 2010/11.³

Discoms with mounting regulatory assets are facing increasing cash-flow problems, jeopardizing their functioning. Borrowing against regulatory assets is becoming less feasible: since commercial banks are not sure how to value regulatory assets that may or may not be worth their face value, discoms can no longer borrow up to the full amount of the regulatory assets they own. Proposals that have been floated include three options for raising funds in order to retire the regulatory assets of the Delhi discoms, rather than imposing continued uncertainty on them about when and how fast their state electricity regulatory commission–approved claims (regulatory assets) can actually be recovered from consumers through the tariff:

- Allow the discoms to issue tax-free bonds offering an 8 percent coupon; or
- Allow the Power Finance Corporation/Rural Electrification Corporation (PFC/REC) to issue tax-free bonds offering an 8 percent coupon, and that PFC/REC onlends the proceeds to the discom at 8.5 percent a year for a period deemed adequate to ensure that the full principal owed to the discoms can be recovered through tariff increases; or

- Allow PFC/REC to directly finance (through fresh loans at their regular lending rate) the amounts owed to discoms, which are being held by discoms as illiquid regulatory assets, for a period corresponding to the requirement to reasonably recover these charges from consumers through the tariff.⁴

Assuming that the full amount owed can be reasonably recovered from consumers within the same period (say eight years) under each scenario, the discoms would accrue the highest benefit under the first option, involving the direct issuance of tax-free bonds—of particular interest to investors in the highest tax bracket.

Sources: ICRA 2012; Nair 2013; Sethi 2013.

Notes

1. Appellate Tribunal's Order of November 11, 2011: The recovery of the Regulatory Asset (RA) should be time-bound and within a period not exceeding three years at the most and preferably within the control period. The carrying cost of the RA should be allowed to the utilities in the annual revenue requirement of the year in which the RA is created to avoid the problem of cash flow to the distribution licensee.
2. It has been estimated that consumer tariffs would have to increase more than three times overnight, with electricity consumption remaining unchanged, in order to fully pay discoms what they are owed in the form of RAs.
3. However, in these states the RAs are captured in the package of short-term loans being arranged for SEBs by the center; this does not apply to Delhi discoms.
4. This is actually already the practice for RAs of state electricity boards (with a state guarantee to PFC/REC), but is at present not allowed for private discoms or joint ventures. One of the Delhi discoms has proposed that this distinction be erased, and that PFC/REC also be allowed to bridge finance the uncollected RAs for private discoms, without a state guarantee.

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A Strategic Model to Improve Distribution Performance—Enersis in Chile

In 1982, Chile became the first Latin American country to introduce wide-ranging reforms in its power sector. Its private distribution companies (discoms), such as Enersis, which was originally responsible for distribution in the Santiago metropolitan region, have been pioneers in improving operational efficiency. Enersis has since expanded into generation and distribution in other Latin American countries, including Argentina, Brazil, Colombia, and Peru. Enersis invested about \$1.2 billion taking over Codensa, the discom serving Bogotá, the capital of Colombia, in 1998. It designed and implemented a strategic model and related action plans to restructure Codensa, with impressive outcomes.

Codensa's productivity reached 2,100 customers per employee, through downsizing combined with outsourcing of a variety of services associated with network expansion and maintenance, information technology (IT), and installation of metering devices. The quality of service improved greatly: average interruption time was reduced by more than 70 percent (from 6.3 hours in 1997 to 2 hours in 2002), and the interruption frequency declined by more than 70 percent (from 11.4 hertz in 1997 to 3.1 hertz in 2002).¹ Total distribution losses steadily declined from 22 percent in 1997 to 9 percent in 2007, with a positive impact on the company's bottom line.

The strategic model followed by Enersis to achieve and sustain market discipline comprises actions in regulation, commercial management, technical management, training and management of external contractors (outsourced services), community engagement, and IT—as well as punitive measures. Highlights include Enersis working with sector authorities and the regulator to achieve:

- A tariff structure that would allow financial sustainability of efficiently managed discoms.

- Tariff rates reflecting costs of efficiently meeting service quality standards, assuring a fair and reasonable equilibrium between electricity consumers and service providers.
- Generation of funds to subsidize low-income and other customers through tariff rates and/or additional charges paid by selected categories of customers, government budgets, grants, or a combination thereof.
- Use of technologies that assure environmentally sustainable and low-cost supply.

The main steps to improve commercial management entailed:

- Integrating the management of metering, meter-reading, billing, collection, disconnection–reconnection, and inspection of meters.
- Enhancing customer service and programs for payment of old debts and regularization of connections.
- Increasing the number of points of contact for customer service to move the company closer to its clients.
- Developing marketing programs to create awareness that electricity is a commercial good with a price.
- Transparent communication to provide customers with information on their rights and obligations.

Technical steps included:

- Construction of distribution networks that are less vulnerable to tampering and irregular connections.
- Systematic field assessments looking for irregular connections, tampered or damaged consumption meters, and unmetered consumers (customers and irregular users).
- Use of boxes to ensure that the consumption meters are properly sealed and cannot be tampered with.
- Use of boxes to seal customer connections.
- Monitoring of public lighting services.
- Monitoring of operational condition of installed seals.

Community engagement involved the following:

- Establishing direct, open contact with communities, their leaders, and the authorities involved to create awareness that electricity is a commercial good with a price and that electricity consumption should be rationalized and efficient.
- Designing and executing campaigns on the culture of regular payment of electricity bills, preserving electricity infrastructure, and behaving safely to avoid electrocution.

Investments in IT required:

- Use of management information systems (MIS) to support commercial and technical functions.
- Development of databases for each MIS, with regular updates and field audits to assure consistency with physical reality.
- Progressive application of automated meter reading devices for monitoring consumption of large and medium-sized consumers.
- Systematic field action on irregular service conditions detected through the commercial MIS.
- Regular updates to ensure inclusion of users into the customer database.

Punitive approaches involved:

- Collaboration with the judiciary to ensure effective action in cases of electricity theft.
- Systematic presentation before the courts of law of cases involving large consumers.
- Police action when required.
- Recovery of old debts in selected cases through judicial actions.
- Publicity to instances of electricity theft involving prominent members of society, to promote social condemnation.

Source: World Bank 2013.

Note

1. “Experience in Reduction and Monitoring of Nontechnical Losses in Latin America”. Energis-Endesa. Presentation to government officials of the Dominican Republic by José Inostroza (CEO-Codensa), February 2005.

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Separation of Carriage and Content in Distribution—Potential Benefits and International Experience

The introduction of retail competition in power markets through the separation of carriage and content is expected to generate large benefits. The logic is clear: multiple retail suppliers will compete for customers based on reliability and service, and prices will fall. The distribution network (wires business) will receive investment upgrades because it is accountable for aggregate technical and commercial (AT&C) losses. The Indian case is examined first, followed by New Zealand, the United States, and Europe.¹ Lessons from these international experiences are looked at last.

India

The Electricity Act 2003 foresees competition in the distribution segment, in part through the separation of the wires business (carriage) from the retail supply (content) business. To date however, competition, and the benefits of price discovery and private participation, have been largely confined to generation. Distribution licensees in India, mostly state government–owned distribution companies (discoms), remain “bundled” in the sense that the wires and the supply business are combined. Even under the few urban franchise operations, the retail customer is unable to benefit from competition among retail suppliers.

Through the introduction of contractual agreements for carriage of electricity over the network, the segregation of wires and supply could help achieve a number of objectives. The owner of the network, who receives payment for “carriage,” becomes accountable for losses incurred and discrepancies between the metered quantity of power injected into the system versus the metered quantity of power delivered.

The benefits of segregation include:

- Identifying and containing the wheeling costs of power by focusing on reducing technical losses.
- Increasing the focus on wires system strengthening and development.
- Increasing accountability, transparency, and commercial prudence and thereby reducing and controlling AT&C losses.
- Introducing competition in retail supply and offering consumers a choice of supplier by commoditizing electricity.
- Improving customer service.
- Helping to develop an energy market.
- Achieving long-term commercial viability of the power sector by improving efficiency. With separation of carriage and content, those (likely larger) customers who prefer to directly procure power from the generator would still incur wheeling charges, but no longer need to pay a cross-subsidy surcharge (as they do now) because the erstwhile discom's business model would change to that of a wires business: its revenues would be mainly derived from wheeling charges for the use of its network and it would rely less on earnings from the retail customers it still serves. By contracting directly with generators, the very largest customers (such as 1 megawatt [MW] and above) will thus act as their own retail suppliers. In addition, some retail suppliers could choose to procure additional power directly from a generator, and supply it to customers, for instance, with a reliability surcharge.

One cautionary note here concerns institutional capacity at the state regulator level. Appropriate regulation will be necessary, along with well-designed contractual clauses that penalize poor performance, in order to incentivize the state discom, as the monopoly owner and operator of the network, to upgrade it, i.e. invest in reduction of AT&C losses and strengthening of wires systems. The performance of many state electricity regulatory commissions (SERCs) has not been exemplary even under the bundled model (before separation of carriage and content), and it may be a challenge for them to take on this additional complexity.

Separating Carriage and Content

Segregation needs to be accomplished gradually, while retaining government (state discom) ownership of the monopoly wires network, at least initially. Some ideas are:²

- Because the state discom is not well equipped to handle large investments in loss reduction and upgrading of wires, the discom could competitively select a set of operation and maintenance (O&M) subcontractors for concentric operational circles of the network.
- The O&M subcontractors would have service agreements with the discom, and would be paid by it for improvements made to its wires as well as for the

O&M necessary to achieve the contracted service levels. In their operational circles, they would be responsible for O&M to ensure network availability; network strengthening and expansion; technical and commercial loss reduction; and consumer metering. This is similar to the responsibilities of distribution franchises, although without the direct customer interface, which would be the remit of the retail supplier(s). The discom's role would be relatively hands off. As the "owner" of the wires, its revenue stream would depend on wheeling charges paid by competing retail suppliers.

- To avoid a breakdown of confidence between generators holding 25-year power purchase agreements (PPAs) and the discom (in its new role of network owner and operator without direct access to revenues from retail sales)³ during the transition, a successor entity with the same creditworthiness as the "old discom" is required to "take over" the existing contracts. A bulk procurer for the state is proposed to be created on paper and to inherit all the contractual obligations of the old discom. This would give comfort to generators that their 25-year contracts for power supply would continue to be honored during the transition to full separation of the wires and supply businesses.

Multiple retail suppliers that source their own power, including from the bulk procurer, for sale to consumers should be prequalified, competitively selected, and licensed by the SERC. Initially the SERC should license *and* regulate the retail supply business; over time, as competition takes off among retail suppliers, the SERC may only license them and may deregulate the retail supply business as margins charged by retailers will be better determined by competition. All retailers will still pay wheeling charges for the wire service, which will be passed through to consumers.⁴

The merits of this model are that the wires business is not simply handed over to the state discom without further attention to how AT&C losses will be reduced, but that private O&M operators are proposed to be contracted by the discom in order to bring about loss reduction in operational circles; the bulk procurer provides continuity to the generators while taking the state discom out of being a counterparty to PPAs, in keeping with its new wires-only focus; and retail suppliers gradually increase in number in order to provide consumers with the possibility of choice and benefits of competition among last-mile service providers.

New Zealand

Retail competition is thriving, meaning that separation of carriage and content has been successfully concluded. Most New Zealand consumers have a choice of 20 retail brands selling power. The Electricity Industry Act of 2010 provided for the electricity market to be governed by the Electricity Industry Participation Code (the Code), overseen by the Electricity Authority, with effect from November 2010. The Code promotes retail competition by specifying efficient switching processes (from one supplier to another) and by allowing any party to

be an electricity retailer, provided that minimum standards are met. Retailers and a few large, industrial customers typically buy electricity directly from the spot market.

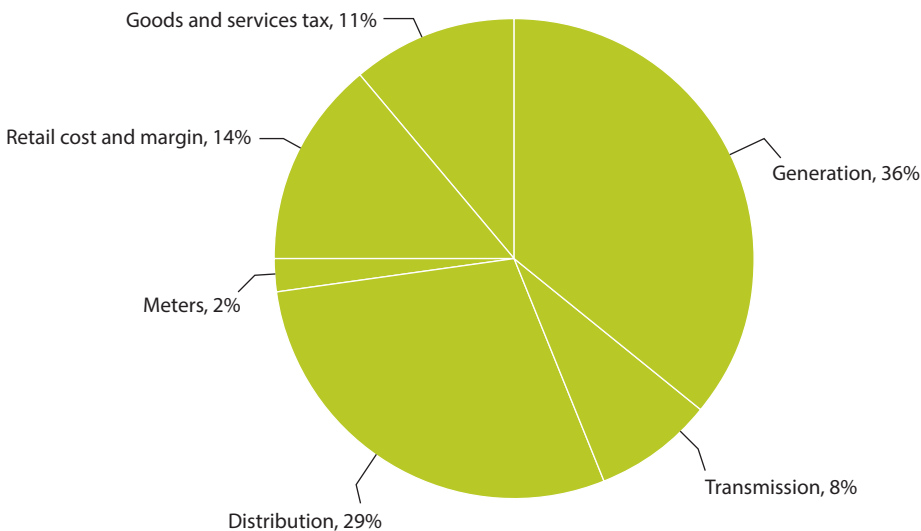
Institutional Underpinnings Are Crucial to Support Smooth Implementation of Retail Competition

- **Consumer Switching Fund:** To help strengthen competition in the retail sector, the Act provided for the establishment of a 3.5 year Consumer Switching Fund, for which the first initiative was an awareness campaign to promote to consumers the benefits of comparing and switching retailers. In partnership with the Ministry of Consumer Affairs and Consumer NZ, the fund aims to improve the flow of information through the system, to increase consumers' readiness to switch suppliers, and as a result to permanently lock in pressure on retailers to produce innovative pricing plans and service offerings. During the first 90 days of the campaign, over 390,000 people visited the website and 128,000 switches took place.
- **Metering:** Metering is a critical part of retail market operations. The Code specifies requirements for meter performance and maintenance including meter suppliers' responsibilities and standards for accreditation of metering test houses. Twenty test houses are currently approved by the Authority to certify that metering systems are operating accurately, and all test houses are audited periodically. The rollout of advanced metering in New Zealand is a significant technological advance being led by retailers. The rollout is voluntary and provided at no additional direct cost to consumers. Advanced metering can allow consumers to analyze expenditures and control costs by running appliances at least-cost times of the day and will play an important part in the uptake of smart appliances and electric vehicles. It also enables distributors and retailers to manage their portfolios more cost-effectively; this eases pressure for investment in new generation, transmission, and distribution assets.
- **Market Administration:** The Authority contracts out the services required to operate the retail and wholesale electricity markets, apart from the market administration function, which it performs itself, such as appointing auditors of metering test houses and metering installations and specifying backup procedures in the event of a failure of market systems. Two separate private contractors handle "registry" and "reconciliation."
 - **Registry:** This is managed by a competitively selected private contractor. The registry is a national database containing information on 2 million points of connection at which electricity is supplied. Referred to as Installation Control Points, each one has a unique identifier which is used in managing customer switching and reconciliation processes.

- **Reconciliation:** Ensuring that industry participants are allocated their correct share is essential to operating an efficient market. To facilitate this, the competitively contracted reconciliation manager receives and processes about 50 million metering data points on a monthly basis, reconciles them against a register of contracts, and passes the data to industry participants.
- **Distribution (“carriage”).** Twenty-nine companies are involved in distributing power to consumers through regional networks of overhead or underground cables. While the distribution network is connected to the national grid, there are 105 secondary, or “embedded,” networks that connect to distribution networks and in turn supply clusters of consumers at specific sites (including airports, major retail complexes, and shopping malls). There is also a growing number of embedded generators that connect directly to distribution networks rather than to the national grid. Currently there are 83 embedded and partially embedded generators with individual capacity of more than 1 MW. Apart from this there are several hundred smaller-scale embedded generators connected to distribution networks throughout the country.

Despite the separation of carriage and content, it seems that the monopoly nature of the wires business (“carriage”) still confers advantages relative to the “content,” which is subject to competition. On average, distribution network costs account for about 29 percent of New Zealanders’ annual expenditure on electricity, whereas retail costs account for just 14 percent (figure L.1).

Figure L.1 Breakdown of New Zealanders’ Annual Expenditure on Electricity



Source: Electricity Authority, Te Mana Hiko 2011.

The United States

Some 20 U.S. states have implemented varying degrees of retail restructuring, in which consumers were given the right to purchase power from nonutility providers. The incumbent—once vertically integrated—utility may continue to serve customers who elect to buy from it, but for customers who choose an alternative power supplier, the incumbent acts solely as a wires and service provider, not as a seller of electricity. In an attempt to prevent incumbent utilities from having a competitive advantage over alternative suppliers, the incumbent was generally required to divest its generating plants, usually to an unregulated affiliate.

Customers who continue to purchase power from the incumbent utility receive what is known as standard-offer or “default” service. While the costs of transmission and distribution remain regulated by state regulators on a cost of service basis, the cost of electricity generation, whether provided by the incumbent utility or an alternative nonutility supplier, reflects the cost of purchasing power on the wholesale market or through bilateral contracts. As a result of separation of carriage and content, a much larger pool of customers is now exposed to the wholesale power rates than would have been the case in the absence of restructuring and retail customer access.

To the extent that the wholesale market for power generation does not appear to be “workably competitive,” all customers, not just those of public power and rural electric utilities, are ill-served. Access to alternative retail suppliers does not solve the fundamental problems of the wholesale market from which those suppliers must purchase power. In 2011 returns on equity for a sample of the largest merchant generators (who previously used to have regulated caps on their returns) ranged from 15 percent to 23 percent, rates far exceeding regulated utility returns. Continued market power was reflected in the difference between fuel costs (falling) and electricity prices (rising) in 2011. Other data for the U.S. electricity market show that the beneficiaries of restructuring have not been consumers, as promised, but owners of formerly regulated—and largely depreciated—generating units.

European Union

While the introduction of competitive retail and generation markets in the 1990s and early 2000s brought about a dramatic restructuring of the electricity industry and regulatory environment, the underlying power sector paradigm changed little. Large, central-station power plants continued to supply the vast majority of electricity, delivered to customers over a hierarchical chain of high-voltage transmission lines and lower-voltage distribution networks (Jenkins 2013).

Today, new forces are upending much of that traditional paradigm, sparking changes at least as profound as those unleashed by the earlier era of industry liberalization. According to Eurelectric (2013), four major trends are reshaping the global power sector, for which Europe is likely to be the bellwether: growth

of renewable energy, a more decentralized system, foundation of the smart grid, and retail competition and new services.

Increasingly competitive retail markets are creating new opportunities—and pressures—for innovative ways of delivering value to electricity users. Greater product differentiation is more possible now than ever before, and consumers are becoming more engaged, looking for ways to get more out of their relationship with their retail supplier. Those retailers who evolve to meet customer demands will thrive, while others will see their market share wither.

With declining profitability in the utilities' core business areas, the future for utilities rests on capturing the growing pool of value associated with renewable and distributed energy generation and other emerging technologies, capitalizing on their existing relationship with customers, and finding novel ways to serve customer needs through new business models and services. While the large-scale renewable energy sector will continue to grow in value, with the European Union adding 135 GW of new renewable energy capacity by 2020 and creating an additional €14 billion value pool, utilities have so far failed to capture a substantial share of these new value pools: Germany's four largest power producers controlled less than 5 percent of renewable energy capacity as of 2012, for example.

Today, electric utilities everywhere need to be cognizant of a variety of disruptive technologies⁵ that are emerging to compete with utility-provided services and that will threaten the centralized utility model—or at the least will reduce the customer base and hence affect revenue expectations of utilities' investors.

Such threats relate particularly to the “carriage” or fixed-line distribution network. Due to the intermittent nature of renewable energy technologies, there has tended to be a presumption on the part of utilities that customers will always need to remain on the grid; however, 10 years ago most people would not have believed that traditional telephone land-line customers could “cut the cord.” If, as seems likely, viable and economic renewable-energy storage technology is not far off, this will sharply reduce the need for carriage, as it will permit the production of power close to where it is consumed.

Threats to the centralized utility model are also likely to come from new technologies or customer behavioral changes that reduce load. Any cost-recovery paradigms and regulations that force cost of service to be spread over fewer units of sales (that is, kWh) serve to enhance the growing competitive threat of disruptive alternatives and will likely lead to pressures to revise tariff structures, such as through a higher fixed-charge component. Customers are not precluded from leaving the system entirely if a cost-competitive alternative is available (in a scenario where efficient energy storage is combined with distributed generation, this could create the ultimate risk to grid viability). Tariff restructuring to restore lost revenues will be only a temporary fix against the threat of customers fully exiting, or at best solely using the grid for backup purposes (as with the telephone landline). An old-line industry with a business model requiring 30-year cost-recovery of investment is clearly vulnerable to threats from disruptive forces.

What can utilities do? Eurelectric (2013) advises utilities to embrace renewable energy technologies and invest in the in-house development and addition of the following value added services in order to remain relevant to customers:

- Ongoing take-up of distributed generation creates business opportunities to provide, install, and maintain new equipment at customers' premises, as well as additional potential services, such as virtual power-plant generation models.
- Continued energy efficiency improvement will create a market for a wide range of technical solutions and, equally importantly, advisory services on new business models to unlock the potential value that energy-saving solutions entail.
- As part of providing system flexibility, the importance of demand response aggregation will grow. A market involving business-to-business customers is already emerging and is likely to extend to the business-to-consumer segment through two-way digital communication enabled by smart grids and the increased penetration of smart appliances and home-control technologies.
- Future adoption of electric vehicles will require e-mobility solutions for private and fleet customers, spanning the development of charging infrastructure (public charging stations and private charging boxes), power supply, and automatic billing and data management.

Concluding Observations

What does the above imply for the debate on retail competition in the Indian context? Two primary considerations stand out, depending on whether one takes a static or dynamic perspective.

For a static view, the New Zealand case illustrates the pressing need for strong institutional support to make retail competition successful. In that country, the public sector took an active interest to make it seamless for customers to switch in and out of hiring various retail suppliers; it therefore set up mechanisms and allocated resources and expertise, with great success. In the United States, retail competition was not similarly supported by the public sector, and communications between retail suppliers and customers were left to individual initiative on both sides. The retail switching rate in the United States has been far lower as a result. A study of the experience with retail competition in 27 European countries (Lima 2003) also concluded that retail competition itself had less to do with customers' tariff rates than did the bulk-procurement strategies of new-entrant retail suppliers, which could pass on savings to customers and thereby entice some switching. Most of the switching was done by industrial customers who had sophisticated procurement departments and were able to analyze the value propositions of alternative offers better than the typical residential customer. European countries where some modest success with retail competition was observed also had dedicated public resources and institutional capacity to support consumers.

From the dynamic perspective, if Europe is indeed taken as a bellwether for the future of the centralized utility model, the relevance of the carriage and content model in the long run would have to be questioned. If there is a disruptive technological innovation in the coming decade that allows distributed generation and power storage at affordable rates and grants complete independence from the grid for a large number of low-tension consumers, this will be a game changer for centralized utilities, their investors, and their regulators (*The Economist* 2013a). There is therefore a risk of new investments by the utility becoming stranded, and revenues being hard to recover.

India is different in one critical respect from the other countries discussed here: it has a shortage of power.⁶ However, this means there is even more risk of customers “leapfrogging” to a new technological paradigm if one becomes available and deserting the utility or using it as backup only.⁷ Utilities that cannot offer quality service to existing customers and that have a large unserved pool of potential customers are very vulnerable to any technological change that lets consumers get reliable power at their own location.

On balance, given the constrained institutional capacity available to provide the required consumer support, the still-developing regulatory capacity at state level, and developments on the distributed generation front, it is probably wiser for India to start with pilot projects for retail competition rather than make a full-scale rollout at present.

Sources: Abbott, Holdaway, and Cohen 2007; Caplan and Brobeck 2012; Electricity Authority, Te Mana Hiko 2011; Eurelectric 2013; Jenkins 2013; Lima 2003; *The Economist* 2013a, 2013b.

Notes

1. New Zealand introduced retail competition in 2010, whereas the United States and Europe did so nearly three decades ago, and are now dealing with a new raft of issues that pose existential threats to their conventional, utility-centric business model.
2. This draws upon ideas put forward by Anil Sardana, Managing Director of Tata Power, in a private communication.
3. The “old discom” was the signatory of the PPA, procuring bulk power (under Case 1 or Case 2 methods), and was responsible for both carriage and delivery of the content to the end user. The proposed “new discom” would be concerned only with the network, and would not necessarily be a good contractual counterpart with the generators because it no longer has relationships with customers, and therefore cannot be sure of secure offtake for the power it purchases. The new discom would therefore want to relieve itself of 25-year obligations to purchase power.
4. Depending on the electricity markets the retail supplier concept is implemented in, there may be limited or no response to the competitive bids seeking interested retail suppliers. In such cases, a single “appointed” retail supplier may be needed, acting as a temporary subcontractor to the public sector for a fee. This could be a transition mechanism for, say, three years, after which the customer database, collection rates, etc. would be published online as updated information provided to potential bidders under a new bidding round, perhaps related to concentric circles so that new retail suppliers would not have to begin by taking on the entire customer base. After another three-year transition, during which customers would have a chance to assess

the performance of different retail suppliers operating in the small circles, various retail suppliers could step “across lines” and acquire customers outside their initially prescribed service territory limits (which were confined to the initial concentric circles).

5. Photovoltaic, battery storage, fuel cells, geothermal energy systems, wind, micro-turbines, and electric vehicle enhanced storage.
6. This also constrains retail competition because entrants cannot easily source power that is not already tied up in power purchase agreements.
7. Again, the analogy with mobile telephony is appropriate: mobile phones were long considered luxury items, and thus the rapid and deep penetration of mobile telephony in developing economies was predicted by very few observers.

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Productive Use of Electricity— Experience from Indonesia and Peru

Productive use of electricity has been promoted as part of rural electrification initiatives in Indonesia and Peru to encourage the adoption of electricity for income generation activities and improve the financial viability of rural electrification. The effort in Indonesia, implemented under the framework of the World Bank–supported Indonesia Rural Electrification Projects I & II in the early 1990s, pioneered the application of Business Development Services (BDS) for productive uses of electricity. The project focused on outreach to small businesses through nongovernmental organizations (NGOs), and developed a marketing strategy for the electricity supplier, which addressed lack of information, tariff barriers, and quality of service. Impact studies show that 66,000 enterprises were assisted and over 20,000 jobs created.

The approach to promoting productive uses of electricity was replicated on a pilot basis in Peru as part of a rural electrification project initiated by the government in 2006. Before the project, rural communities faced multiple barriers to increasing the use of electricity for production including limited technical and management skills of rural producers, inadequate access to capital and financing, and perception of poor quality of grid supplied electricity, which reduced interest in electrical equipment.

The Peru project signed a standard memorandum of understanding with three distribution companies involved in the pilot, establishing the role, responsibilities, and support to be provided by the distribution company and the to-be-contracted NGOs and the coordination arrangements. As in Indonesia, the project implemented an approach based on BDS techniques. The NGOs selected to implement the productive uses activities used BDS methods to assist small and home-based enterprises in gathering information, finding credit, and addressing technology constraints through marketing and assistance campaigns. To promote productive uses of electricity, the NGOs followed a strategy that included

market assessment; preparation of business plans, marketing to the community and potential entrepreneurs, coordination with complementary institutions, and links to the electricity distribution company.

By 2011, pilot project activities had helped over 4,970 families and micro-enterprises adopt electricity and use equipment to process cereals, coffee, cocoa, baked goods, meat products, milk, wood and metal products, and handicrafts, and to pump water for expanded agricultural production and processing. It was expected that by project closing (June 2013), 9,000 families and micro-enterprises would have been supported in adopting productive uses of electricity.

The theme of this project has been integrated into government objectives—Peru’s Ministry of Energy and Mines National Plan for Rural Electrification includes capacity building for productive uses. A follow-up rural electrification project to be implemented by the government will work to make promotion of productive uses an integral part of rural electrification activities of the General Directorate of Rural Electrification rather than a separate pilot activity.

Source: Finucane, Bogach, and Garcia 2012.

Reference

Finucane, James, Bogach V. Susan, and Luis E. Garcia. 2012. *Promoting Productive Uses of Electricity in Rural Areas of Peru: Experience and Lessons Learned*. World Bank, Washington, DC.

APPENDIX N

**Regression Results—Governance
and Performance**

Table N.1 Regression of Utility Performance on State, Utility, and Corporate Governance Variables, 2010

		<i>Dependent variable: profit per unit excluding subsidies (2010)—all utilities</i>				
State-level controls	GDP per capita, 2009	0.454 (0.167)***	0.463 (0.154)***	0.416 (0.147)***	0.421 (0.151)***	0.442 (0.146)***
	Regulatory governance ID index	0.898 (0.255)***	0.751 (0.243)***	1.031 (0.284)***	0.865 (0.275)***	0.948 (0.277)***
	Regulatory governance IM index	0.358 (0.731)	0.391 (0.753)	-0.267 (0.701)	0.372 (0.675)	-0.233 (0.777)
Utility-level controls	Discom dummy	-0.666 (0.195)***	-0.695 (0.180)***	-0.57 (0.186)***	-0.619 (0.191)***	-0.634 (0.181)***
	Net fixed assets, 2009	-0.199 (0.084)***	-0.072 (0.065)	-0.078 (0.076)	-0.094 (0.08)	-0.064 (0.068)
Corporate governance variables	Profit per unit, 2007	0.393 (0.179)**	0.303 (0.169)*	0.31 (0.168)*	0.365 (0.172)**	0.265 (0.16)
	Basic CG index	0.274 (0.467)				
	Share of executive directors on board		-0.83 (0.347)**			-0.688 (0.346)*
	Share of independent directors on board			1.279 (0.566)**		1.088 (0.550)*
	Number of directors on board				0.026 (0.027)	
	Constant	-3.994 (1.444)***	-4.794 (1.491)***	-4.422 (1.488)***	-4.731 (1.463)***	-4.509 (1.480)***
	R^2	0.48	0.48	0.49	0.47	0.51
	N	61	62	62	63	62

Note: CG = corporate governance; discom = distribution company; GDP = gross domestic product; ID = institutional design; IM = implementation of key regulatory mandates. Values in parentheses are White standard errors.

Significance level: * = 10 percent, ** = 5 percent, *** = 1 percent.

Table N.2 Regression of Utility Performance on State, Utility, and Corporate Governance Variables, 2011

		<i>Dependent variable: profit per unit excluding subsidies (2011)—all utilities</i>				
State-level controls	GDP per capita, 2010	0.288 (0.143)**	0.318 (0.137)**	0.289 (0.140)**	0.278 (0.138)**	0.313 (0.136)**
	Regulatory governance ID index	0.638 (0.232)***	0.621 (0.222)***	0.77 (0.256)***	0.701 (0.216)***	0.697 (0.263)**
	Regulatory governance IM index	1.197 (0.885)	0.93 (0.82)	0.745 (0.898)	0.972 (0.829)	0.743 (0.864)
Utility-level controls	Discom dummy	-0.68 (0.126)***	-0.704 (0.123)***	-0.654 (0.123)***	-0.664 (0.125)***	-0.689 (0.122)***
	Net fixed assets, 2010	-0.095 (0.058)	-0.081 (0.054)	-0.094 (0.055)*	-0.103 (0.058)*	-0.081 (0.054)
	Profit per unit, 2007	0.254 (0.122)**	0.206 (0.118)*	0.228 (0.116)*	0.251 (0.116)**	0.196 (0.114)*
Corporate governance variables	Basic CG index					
	Share of executive directors on board			-0.522 (0.264)*		
	Share of independent directors on board			0.507 (0.39)		
	Number of directors on board				0.02 (0.024)	
	Constant	-3.376 (1.694)*	-3.536 (1.549)**	-3.315 (1.661)*	-3.337 (1.601)**	-3.457 (1.555)**
R^2	0.52	0.54	0.53	0.53	0.55	
N	65	65	65	66	65	

Note: CG = corporate governance; discom = distribution company; GDP = gross domestic product; ID = institutional design; IM = implementation of key regulatory mandates. Values in parentheses are White standard errors.

Significance level: * = 10 percent, ** = 5 percent, *** = 1 percent.

Table N.3 Regression of Utility Performance on State, Utility, and Regulatory Governance Variables, 2010

<i>Dependent variable: profit per unit excluding subsidies (2010)—all utilities</i>			
GDP per capita, 2009	0.483 (0.144)***	0.48 (0.141)***	0.535 (0.150)***
Discom dummy	−0.564 (0.169)***	−0.563 (0.168)***	−0.568 (0.169)***
Net fixed assets, 2009	−0.107 (0.069)	−0.104 (0.068)	−0.126 (0.066)*
Profit per unit, 2007	0.371 (0.142)**	0.388 (0.147)**	0.377 (0.146)**
Regulatory governance ID index	0.714 (0.243)***	0.853 (0.268)***	
Regulatory governance IM index	0.724 (0.707)		1.53 (0.752)**
Constant	−5.218 (1.328)***	−4.73 (1.340)***	−5.796 (1.429)***
R ²	0.52	0.51	0.49
N	80	80	80

Note: discom = distribution company; GDP = gross domestic product; ID = institutional design; IM = implementation of key regulatory mandates. Values in parentheses are White standard errors.

Significance level: * = 10 percent, ** = 5 percent, *** = 1 percent.

Table N.4 Regression of Utility Performance on State, Utility, and Regulatory Governance Variables, 2011

<i>Dependent variable: profit per unit excluding subsidies (2011)—all utilities</i>			
GDP per capita, 2010	0.265 (0.144)*	0.251 (0.140)*	0.329 (0.145)**
Discom dummy	−0.582 (0.128)***	−0.575 (0.129)***	−0.591 (0.128)***
Net fixed assets, 2010	−0.089 (0.051)*	−0.074 (0.052)	−0.108 (0.050)**
Profit per unit, 2007	0.388 (0.138)***	0.425 (0.148)***	0.387 (0.141)***
Regulatory governance ID index	0.668 (0.223)***	0.95 (0.250)***	
Regulatory governance IM index	1.495 (0.843)*		2.262 (0.824)***
Constant	−3.595 (1.457)**	−2.57 (1.323)*	−4.301 (1.489)***
R ²	0.59	0.57	0.57
N	80	80	80

Note: discom = distribution company; GDP = gross domestic product; ID = institutional design; IM = implementation of key regulatory mandates. Values in parentheses are White standard errors.

Significance level: * = 10 percent, ** = 5 percent, *** = 1 percent.

Overview of the India Power Sector Review Databases

A major contribution of the India Power Sector Review (IPSR) is the creation of a database that collates data at utility, state, and central levels covering both a time series for 2003–11 and a cross-section at 2011. The data have been either directly extracted from a published source (such as Power Finance Corporation's Performance Report of State Power Utilities, successive rounds of National Sample Survey, and tariff schedules approved by state regulatory commissions of various years); or obtained from interviews with utilities and regulators:

- *Utility-level* data on financial and operational performance, board structures and composition, and indicators of compliance with good corporate governance practices.
- *State-level* data on the functioning and capacity of regulatory commissions; tariff schedules for all states for several years; electrification rates; performance of Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY); and electricity subsidy volumes and targeting.
- *Central-level* data have been aggregated on public-private partnership (PPP) projects in the generation, transmission, and distribution subsectors since 1990.

Table O.1 Summary of India Power Sector Review Data

<i>No.</i>	<i>Component</i>	<i>Description</i>	<i>No. of variables</i>	<i>Data source</i>	<i>Level</i>	<i>Background paper/synthesis report</i>
1	Utility performance	Financial and operational performance of 101 utilities	67	PFC	Utility level	Beyond Crisis: Financial and Operational Performance of India's Power Sector
2	Corporate governance	Corporate Governance practices of 69 utilities	51	Utility interviews	Utility level	Governance of Indian Power Sector Utilities
3	Regulatory governance	Regulatory Governance practices of 28 SERCs	73	SERC websites and interviews	State level	Governance of Indian Power Sector Utilities
4	Access	Electrification rates	10	National Sample Survey	State level	Power for All: Electricity Access Challenge in India
5	Electricity subsidy	Prevalence, size, and distribution of domestic electricity subsidies	18	National Sample Survey, Tariff Schedules	State level	Elite Capture: Domestic Tariff Subsidies, Power for All: Electricity Access Challenge in India

Source: World Bank compilation.

Note: PFC = Power Finance Corporation; SERC = state electricity regulatory commission.

Table O.2 Utility-Level Data: Financial and Operational Performance

<i>Indicator</i>	<i>Description</i>	<i>Unit</i>	<i>Time series</i>	<i>No. of Obs.</i>	<i>% complete</i>	<i>Theme</i>
Total revenue	Revenue from sale of power + Grants & Subsidies Booked + Revenue from Trading + Other Revenue	Rs million	2003–11	722	100	Revenue
Total revenue – Excluding subsidy	Total Revenue – Subsidy Booked	Rs million	2003–11	722	100	Revenue
Revenue from sale of power		Rs million	2003–11	493	68	Revenue
Other revenue		Rs million	2003–11	504	75	Revenue
Collection efficiency	$100 \times (\text{Net Revenue from Sale of Energy} - \text{Change in Debtors for Sale of Power}) / \text{Net Revenue from Sale of energy}$	%	2003–11	458	63	Revenue
Total costs	Operational Cost + Interest	Rs million	2003–11	722	100	Cost
Operational costs	Sum of power purchase, fuel, O&M costs, depreciation	Rs million	2003–11	722	100	Cost
Power purchase cost		Rs million	2003–11	662	92	Cost
O&M costs	Sum of R&M, A&G, employee cost	Rs million	2003–11	696	96	Cost
R&M costs	Repair and maintenance costs	Rs million	2003–11	721	100	Cost
A&G costs	Administrative and general costs	Rs million	2003–11	719	100	Cost
Employee costs		Rs million	2003–11	721	100	Cost
Other costs		Rs million	2003–11	715	99	Cost
Earnings before interest, taxes, depreciation and amortization	Total revenue – (power purchase, fuel, O&M, other, costs capitalized)	Rs million	2003–11	626	87	Cost
Depreciation		Rs million	2003–11	721	100	Cost
Earnings before interest		Rs million	2003–11	627	87	Cost
Interest		Rs million	2003–11	721	100	Cost
Profit before tax	Total Revenue – Total Expenses	Rs million	2003–11	719	100	Profit
Provision for taxation	Provision for taxation	Rs million	2003–11	639	89	Profit
Profit after tax	PBT-Provision for taxation	Rs million	2003–11	722	100	Profit
Profit after tax excl subsidy booked	PAT-subsidy booked	Rs million	2003–11	722	100	Profit
Grants and subsidies booked	Subsidy booked in utility accounts as arrears, with payment promised by the state government	Rs million	2003–11	712	99	Subsidy
Grants and subsidies received	Subsidy that is actually paid by the government to the utility	Rs million	2003–11	712	99	Subsidy
Equity		Rs million	2003–11	719	100	Financing
Reserves		Rs million	2003–11	718	99	Financing
Accumulated profit/loss	Profit/loss that is carried over to the next fiscal year	Rs million	2003–11	719	100	Financing

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Table O.2 Utility-Level Data: Financial and Operational Performance (continued)

<i>Indicator</i>	<i>Description</i>	<i>Unit</i>	<i>Time series</i>	<i>No. of Obs.</i>	<i>% complete</i>	<i>Theme</i>
Net worth	Sum of equity, reserves, accumulated profits	Rs million	2003–11	718	99	Financing
Consumer contribution		Rs million	2003–11	673	93	Financing
Grants towards capital assets		Rs million	2003–11	683	95	Financing
State government loans		Rs million	2003–11	718	99	Financing
Loans from financial institutions (FIs), banks, bonds		Rs million	2003–11	717	99	Financing
Other loans		Rs million	2003–11	712	99	Financing
Total loans	Sum of loans from FIs, other, state	Rs million	2003–11	721	100	Financing
Capital employed	Sum of total loans, net worth, consumer contributions, grants toward capital assets	Rs million	2003–11	722	100	Financing
Net fixed assets		Rs million	2003–11	716	99	Financing
Capital work in progress		Rs million	2003–11	719	100	Financing
Debtors		Rs million	2003–11	709	98	Financing
Others		Rs million	2003–11	474	66	Financing
Total current assets		Rs million	2003–11	388	54	Financing
Creditors		Rs million	2003–11	527	73	Financing
Other current liabilities		Rs million	2003–11	393	54	Financing
Total current liabilities		Rs million	2003–11	390	54	Financing
Net current assets		Rs million	2003–11	476	66	Financing
Total assets		Rs million	2003–11	396	55	Financing
Capital expenditure		Rs million	2003–11	717	99	Financing
Net input energy	Net input energy = Total input energy adjusted for transmission losses and energy traded For Discoms: Total input energy = Energy purchased + Net generation For SEB/PDs: Total input energy = Energy generated – Auxiliary consumption + Energy purchased	MU	2003–11	465	64	Energy
Energy sold		MU	2003–11	465	64	Energy
AT&C losses	$100 \times (\text{Net input energy} - \text{Energy realized}) / \text{Net input energy}$	%	2003–11	459	64	Energy

Sources: Data are from PFC (2006, 2007, 2008, 2009, 2010, 2011, 2012).

Note: A&G = administrative and general; AT&C = aggregate technical and commercial; discom = distribution company; FI = financial institution; R&M = repair and maintenance; O&M = operation and maintenance; PAT = profit after tax; PBT = profit before tax; MU = million units.

Table O.3 Utility-Level Data: Corporate Governance

<i>Indicator</i>	<i>Unit</i>	<i>Total data coverage</i>	
		<i>(69 utilities), %</i>	<i>Theme</i>
Is there a Board of Directors?	Y/N	100	Board composition
Number of Board Members	#	95	Board composition
Number of Executive Directors on the Board	#	94	Board composition
Number of Government (or holding company) Directors on the Board	#	95	Board composition
Number of Independent Directors on the Board	#	94	Board composition
Is Chairman an Executive Director?	Y/N	95	Board composition
Is Chairman from IAS? (or, for holding company, does Chairman work for government)	Y/N	62	Board composition
Is MD from IAS?	Y/N	62	Board composition
Does the Chairman have other government responsibilities?	Y/N	60	Board composition
What is the average tenure of the MD/CMD (over the past five years)?	#	40	Board composition
Does the utility have an Audit committee?	Y/N	99	Board functioning
Does the Board have an HR (or similar) committee?	Y/N	61	Board functioning
Does the utility have other specialized Board committees? If yes, which one?	Y/N	76	Board functioning
Is Audit committee headed by an Independent Director?	Y/N	51	Audit
Does the utility use external auditors?	Y/N	96	Audit
Is the utility audited by Comptroller and Auditor General of India (CAG)?	Y/N	92	Audit
Is the audit published on the utility's website?	Y/N	99	Audit
Is utility prepared to adopt IFRS standards?	Y/N	85	Audit
Are annual accounts published on the utility's website?	Y/N	99	Accounts
Are annual accounts generally prepared on time (i.e., within 6 months)?	Y/N	79	Accounts
Does the utility have ERP or integrated MIS?	Y/N	65	Performance management
Are targets given to employees for performance management?	Y/N	79	Performance management
Is there a regulatory affairs cell?	Y/N	96	External accountability
Is there a well-defined training policy for employees in place?	Y/N	31	Performance management
Are tariff petitions approved by government before filing?	Y/N	78	External accountability
Share of Board that consists of Independent Directors	%	94	Board composition
Share of Board that consists of Executive Directors	%	94	Board composition
Share of Board that consists of Government Directors	%	95	Board composition
Does utility follow Independent Director good practice of at least 33% independent or at least 50% if the Chairman is an Executive Director?	Y/N	94	Board composition
Does utility follow Executive Director good practice of no more than 50% Executive Directors?	Y/N	94	Board composition
Does utility follow Government Director good practice of no more than two Government Directors?	Y/N	95	Board composition

Source: Data compiled from public sources (state utility websites and annual reports) and, in some cases, interviews.

Note: All data are for 2010. CMD = chairman and managing director; ERP = enterprise resource planning; HR = human resources; IAS = Indian Administrative Service; IFRS = International Financial Reporting Standards; MD = managing director; MIS = management information system; # = variable is measured in numbers.

Table O.4 State-Level Data: Market Structure

<i>Indicator</i>	<i>Unit</i>
Has state utility undergone restructuring (vertical unbundling)?	Y/N
In what year was the state utility restructured?	Year
How many separate companies are there in the state?	#
Is there a holding company in the state?	Y/N
Number of generation companies in the state	#
Number of transmission companies in the state	#
Number of distribution companies in the state	#
Number of trading companies in the state	#
Is there a residual company in the state?	Y/N
Is holding company a licensee?	Y/N
Was transition support provided by government during restructuring?	Y/N
Number of transfer schemes issued and implemented	#
Does the industry structure influence the independent functioning of trading and transmission company?	Y/N
Does the presence of board members of successor entities influence the independent functioning of trading and transmission company?	Y/N
How much subvention was provided by government as transition support?	Rs million/x
Is the holding company chairman a government official?	Y/N
Total number of employees	#
Total number of consumers	#

Source: Data are from both secondary (websites, annual reports) and primary (interaction with State Power Departments) sources; data on total number of employees and total number of consumers are from Planning Commission 2011.

Note: All data are for 2011. Y/N = Yes/No; # = variable is measured in numbers.

Table O.5 State-Level Data: Rural Electrification and RGGVY

<i>Indicator</i>	<i>Unit</i>	<i>Year</i>	<i>Source</i>	<i>Theme</i>
Electrification rate, Total	%	2000, 2004, 2010	NSS: http://mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=31	Access
Electrification rate, Urban	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Rural	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Quintile 1	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Quintile 2	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Quintile 3	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Quintile 4	%	2000, 2004, 2010	See Electrification rate, Total	Access
Electrification rate, Quintile 5	%	2000, 2004, 2010	See Electrification rate, Total	Access
Household budget	Rs	2000, 2004, 2010	See Electrification rate, Total	Affordability
Spending on energy	Rs	2000, 2004, 2010	See Electrification rate, Total	Affordability
Spending on electricity	Rs	2000, 2004, 2010	See Electrification rate, Total	Affordability
Number of hours of supply	Hours	2005	India Human Development Survey: http://www.ihds.umd.edu	Reliability
Village electrification rate	%	2013	RGGVY: http://rggvy.gov.in/rggvy/rggvyportal/index.html	Access
RGGVY sanctioned amount	Rs	2013	See Village electrification rate	Financing
RGGVY revised amount	Rs	2013	See Village electrification rate	Financing
RGGVY disbursed amount	Rs	2013	See Village electrification rate	Financing

table continues next page

Table O.6 State-Level Data: Tariff and Subsidiaries

<i>Indicator</i>	<i>Unit</i>	<i>Theme</i>
Average monthly electricity consumption, Total	kWh	Consumption
Average monthly electricity consumption, Urban	kWh	Consumption
Average monthly electricity consumption, Rural	kWh	Consumption
Average monthly electricity consumption, BPL	kWh	Consumption
Average monthly electricity consumption, APL	kWh	Consumption
Share of households in various electricity consumption brackets—and by income quintile	%	Consumption
Share of households that consume no electricity	%	Consumption
Share of total electricity consumption consumed by each income quintile	%	Consumption
Average tariff paid by households—across all households and by income quintile	Rs	Tariff
Average subsidy given on a subsidized kWh of electricity	Rs	Subsidy
Average cross-subsidy paid on an unsubsidized kWh of electricity	Rs	Subsidy
Share of electricity units that are subsidized	%	Subsidy
Average total monthly subsidy received by households—across all households and by income quintile	Rs	Subsidy
Average total monthly cross-subsidy paid by households—across all households and by income quintile	Rs	Subsidy
Share of total subsidies received by each income quintile	%	Subsidy
Share of households in each quintile that receive no subsidy	%	Subsidy
Share of households in each quintile that receive a subsidy on all consumption	%	Subsidy
Share of households that pay more in cross-subsidies than they receive in subsidies	%	Subsidy
Share of households that receive more in subsidies than they pay in cross-subsidies	%	Subsidy
Fiscal cost of subsidies	Rs	Fiscal
Fiscal receipts from cross-subsidies	Rs	Fiscal

Source: NSS: http://mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=31.

Note: All data are for 2010. APL = above poverty line; BPL = below poverty line; kWh = kilowatt-hour; RGGVY = Rajiv Gandhi Grameen Vidyutikaran Yojana.

Table O.7 State-Level Data: Regulatory Governance

<i>Question</i>	<i>Data availability (out of 28 states)</i>
Year SERC was created	28
Has SERC established chairman position?	28
Average tenure of chairman over past 10 years (or since SERC was created, if less than 10 years)	28
Number of filled SERC member positions (including chairman)	26
Number of staff at SERC	27
Number of professional staff at SERC	20
Size of SERC's budget (Rs Lakh)	25
Budget per household connection	20
Primary source of SERC's budget (state, own revenues, or both)	25
% of SERC budget from state	23
% of SERC budget from own revenues	23
Has state established SERC fund?	28
Does the state have a RIMS?	26
Total number of regulations notified	28

table continues next page

Table O.7 State-Level Data: Regulatory Governance (continued)

<i>Question</i>	<i>Data availability (out of 28 states)</i>
Are regulatory decisions published online?	28
Has SERC issued supply code regulations?	28
Year SERC issued regulations on the electricity supply code	28
Has SERC notified trading regulations?	28
Has SERC issued metering regulations?	28
Metering rate	28
Has SERC issued MYT regulations?	28
Has SERC issued intra-state ABT regulations?	28
Has SERC issued OA regulations?	28
Year OA regulations and orders were issued by SERC	28
Has SERC determined OA surcharge?	28
Has SERC determined OA wheeling charges?	28
Has SERC determined OA transmission charges?	28
# of OA applications SERC has received	28
# of OA applications SERC has approved	28
# of OA applications SERC has implemented	28
Has SERC issued regulations on utilities' standards of performance?	28
Do standards regulations have clearly defined penalties for noncompliance?	28
Are results of the standards of performance measurements published online?	28
Does SERC monitor compliance with performance standards?	25
Does SERC issue penalties for noncompliance?	25
Has SERC issued guidelines for setting up consumer grievance redressal forums?	28
Have discoms established consumer grievance redressal forums?	28
Does SERC have a consumer ombudsman?	28
Does SERC have a consumer advocacy cell?	17
Does SERC hold public hearings before issuing a new tariff order?	28
Does SERC hold public hearings before notifying major regulations?	28
Is there an updated schedule of hearings available on the SERC website?	25
Does SERC publish annual reports?	26
Is the annual report published in the local language?	26
Is the annual report published on the website?	28
What is the most recent annual report available on the website?	26
Has SERC issued regulations on RPO of the distribution licensees?	28
Are the RPOs given as technology-specific targets (e.g., solar and non-solar)?	28
Does SERC monitor compliance with RPOs?	25
Does SERC issue penalties for noncompliance with the RPOs?	24
Has SERC issued regulations for energy efficiency and demand side management (DSM)?	28
Does SERC have any measures or incentives to promote consumer DSM?	24
Has SERC determined an FIT for various types of renewable energy generation?	28
Has SERC issued time of day metering regulations?	28
Does SERC have a provision for a differential or time of day tariff?	28
How many years did the SERC NOT receive tariff filings from every utility?	25

table continues next page

Table O.7 State-Level Data: Regulatory Governance (continued)

Question	Data availability (out of 28 states)
Over the past three years, how many times did SERC take more than 120 days to issue a tariff order after receiving the ARR filing from the utility?	26
Average delay in tariff issuance	28
# of tariff orders published over last 13 years	28
# of tariff increases in last 6 years	28
Does 2012 tariff cover average operating cost?	28
How many times has a tariff decision been challenged in the Appellate Tribunal?	28
How many of those challenges were successful?	28
Has SERC ever conducted a cost of supply study?	28
What is the most recent year for which SERC conducted a cost of supply study?	25
MYT order issued?	25
Whether the FPPCA is on annual or quarterly basis	28
Has SERC prepared a time-bound program on reduction of AT&C losses?	28
Has the state established special courts for prosecuting electricity theft?	28
Has the state established a SERC advisory committee?	28
Does the advisory committee have a constitution published online?	26
Does the advisory committee publish minutes of its meetings online?	26
What is the date of the most recent minutes published online?	26

Source: Data were obtained from a combination of secondary sources—websites, annual reports, Tariff Orders, and the website of the Appellate Tribunal and decisions—and supplemented with interviews with selected SERCs.

Note: All data are for 2010. ABT = availability based tariff; ARR = annual revenue requirement; AT&C = aggregate technical and commercial; discom = distribution company; FIT = feed-in tariff; FPPCA = fuel and power purchase cost adjustment; MYT = multiyear tariff; OA = open access; RIMS = regulatory information management system; RPO = renewable purchase obligation; SERC = state electricity regulatory commission; # = variable is measured in numbers.

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APPENDIX P

Background Papers

Background paper 1: Banerjee, Sudeshna G., Doug Barnes, Bipul Singh, Kristy Mayer, and Hussain Samad. 2013. "Power for All: Electricity Access Challenge in India." World Bank, Washington, DC.

Background paper 2: Mayer, Kristy, Sudeshna G. Banerjee, and Chris Trimble. 2013. "Elite Capture: Domestic Tariff Subsidies in India." World Bank, Washington, DC.

Background paper 3: Mukherjee, Mohua. 2013. "Private Sector Participation in the Indian Power Sector: Lessons from Two Decades of Experience." World Bank, Washington, DC.

Background paper 4: Pargal, Sheoli, and Kristy Mayer. 2013. "Governance of Indian Power Sector Utilities: An Ongoing Journey." World Bank, Washington DC.

Background paper 5: Khurana, Mani, and Sudeshna G. Banerjee. 2013. "Beyond Crisis: Financial and Operational Performance of India's Power Sector." World Bank, Washington, DC.

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Two decades after the liberalization of India's economy and a decade after the passage of the forward-looking Electricity Act of 2003, how has India's power sector done? *More Power to India: The Challenge of Electricity Distribution* assesses progress in implementing the government's reform agenda and examines the performance of the sector along different dimensions. The sector has come a long way, as shown in this report, with significant achievements on many fronts. Several states, programs, and utilities could indeed be beacons for others and are worthy of emulation.

Overall, however, the sector's potential remains unrealized. The lack of reliable power is a leading concern and a potential constraint to growth. Annual per capita consumption is low by global standards and 300 million people lack electricity while the peak deficit is more than 10 percent. Unlike 10 years ago, today stakeholders outside of government, specifically the regulator and commercial financial institutions, critically affect the operating environment and thus power utility performance. The incentives of these players and the state government (both as policy maker and as owner) need to be aligned to support utility performance. Support from the center for pilots and experimentation with different models of service improvement, leveraging India's diversity and size, can be an important contribution. The Electricity Act of 2003 and associated policies constitute an enabling policy and regulatory framework for the sector's development—the authors argue that the focus now must be on implementation.

More Power to India: The Challenge of Electricity Distribution will be of interest to policy makers and government officials, academics, and civil society in the fields of energy, governance, and infrastructure economics and finance, as well as private investors and lenders in the energy arena.



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