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DIRECTIONS IN DEVELOPMENT
Energy and Mining

Private Participation in the Indian Power Sector

Lessons from Two Decades of Experience

Mohua Mukherjee

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Foreword

The Indian experience of more than two decades of experimentation and adaptation in attracting private capital to invest in the power sector has much to offer the rest of the world, particularly countries that are still attempting to expand electricity coverage. The passage of the Electricity Act of 2003 represented a landmark for the Indian power sector, and implementation of the act over the past decade also has offered a rich set of lessons in the generation, transmission, and distribution sectors.

Indian power sector authorities and policy makers appreciated early on that the response to a critical shortage of electricity and a supply–demand imbalance should not be limited to an increase in generation only. Accordingly, a steady focus has been centered on increasing the footprint and carrying capacity of the transmission grid, raising voltages, and connecting regional grids to allow power to flow from surplus to deficit regions. Interesting approaches have been tried in the distribution sector. To attract private sector management in that sector, authorities and policy makers have offered incentives to upgrade the distribution network and focus on customer service. An elaborate regulatory apparatus has been set up at the central and state government levels.

Much has been achieved, and the Indian power sector can rightfully take its place among the bold reformers. Yet a large agenda remains, and a more rigorous focus on implementation will be required. Close coordination among various stakeholders and unrelenting attention to efficient execution through decentralized authority to make technical decisions, together with a robust emphasis on monitoring, evaluation, and transparent sharing of data and performance statistics, will help in achieving this objective.

Electricity will remain a crucial underpinning to India’s growth aspirations, and once these are attained, the sector will need to function reliably and continuously to maintain the country’s economic prosperity. This agenda will therefore remain in the forefront for many decades to come. We trust that some of the early lessons of experience, which are captured in this book, will be helpful in moving the debate forward.

Julia Bucknall
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Acknowledgments

This book is a background study for the India Power Sector Review undertaken by the World Bank at the request of the government of India in 2012. The research and data in this book are mostly for the two decades ending in 2012. However, in view of the important developments in the Indian power sector that occurred in 2013, I have added at the end of the book a chapter that summarizes and updates some of the headline developments up to April 2014.

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About the Author

Mohua Mukherjee is a Senior Energy Specialist in the World Bank's Global Energy Practice, working on issues related to distribution utility reform, energy policy, and renewable energy. Most of her career has been at the World Bank, where she has been privileged to work on a variety of development projects in more than 30 countries. Those projects involve the water and sanitation sector, health and education sector, private sector development and microfinance, trade policy and export-led development, financial workouts for countries during the commercial banking crisis in Latin America, agribusiness in Africa, and, for the past several years, the energy sector. She has also worked in the private sector for five years as an investment banker in Nairobi, Kenya, where she headed the corporate finance unit at two international banks and led the introduction and rollout of financial products that were new to the East African market.

Abbreviations

ACQ	annual contracted quantity
AECL	Ahmedabad Electricity Company Ltd.
APDRP	Accelerated Power Development and Reforms Programme
AT&C	aggregate technical and commercial (loss)
BOOM	build-own-operate-manage
BSEB	Bihar State Electricity Board
BSES	Brihanmumbai State Electricity Supply
Bt	billion tons
CAGR	compound annual growth rate
capex	capital expenditure
CCEA	Cabinet Committee on Economic Affairs
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CESC	Calcutta Electric Supply Corporation
CIL	Coal India Ltd.
COD	commercial operation date
CoS	cost of supply
CPSU	central public sector undertaking
CTU	central transmission utility
CZ	Central Zone
DBFOT	design-build-finance-operate-transfer
DF	distribution franchisee
DFA	distribution franchisee agreement
discom	distribution company
DT	distribution transformer
DVVNL	Dakshinanchal Vidyut Vitran Nigam Ltd.
EOI	expression of interest
EPC	engineering, procurement, and construction
EZ	Eastern Zone

FSA	fuel supply agreement
FY	fiscal year
GenCo	generation company
GTD	generation, transmission, and distribution
GW	gigawatts
H1	highest bidder
HVPNL	Haryana Vidyut Prasaran Nigam Ltd.
IPP	independent power producer
IPTC	independent power transmission company
JUSCO	Jamshedpur Utilities and Services Company
JV	joint venture
KESCO	Kanpur Electricity Supply Company Ltd.
kV	kilovolt
kWh	kilowatt-hour
L	lowest bidder
LOI	letter of intent
MNRE	Ministry of New and Renewable Energy
MOP	Ministry of Power
MOU	memorandum of understanding
MSEB	Maharashtra State Electricity Board
MSEDCL	Maharashtra State Electricity Distribution Company Ltd.
Mt	metric ton
MU	million units
MW	megawatt
NPA	nonperforming asset
NPC	Noida Power Company
NSM	National Solar Mission
NTPC	National Thermal Power Corporation
NVVN	NTPC Vidyut Vyaparan Nigam Ltd.
O&M	operation and maintenance
OERC	Orissa Electricity Regulatory Commission
PC	Planning Commission
PFC	Power Finance Corporation
PGCIL	PowerGrid Company of India Ltd.
POC	point of connection
POWERGRID	Power Grid Corporation of India Ltd.
PPA	power purchase agreement
PPP	public-private partnership
PPPAC	Public Private Partnership Approval Committee

PSP	private sector participation
R-APDRP	Restructured APDRP
REC	Rural Electrification Corporation Ltd./renewable energy certificate
R-LNG	regasified liquefied natural gas
RFP	request for proposal
RFQ	request for qualification
RGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RPO	renewable purchase obligation
SBD	standard bidding document
SEB	state electricity board
SECL	Surat Electricity Company Ltd.
SERC	state electricity regulatory commission
SHR	station heat rate
SPPS	single-point power supply
SPV	special purpose vehicle
T&C	technical and commercial
TEC	techno-economic clearance
TPC	Tata Power Company
TransCo	transmission company
TSA	transmission service agreement
UMPP	ultra mega power plant
UPPCL	Uttar Pradesh Power Corporation Ltd.
VGf	viability gap funding
WBSEB	West Bengal State Electricity Board
WZ	Western Zone

Overview

The 2005 National Electricity Policy of the government of India recognizes electricity as one of the key drivers for rapid economic growth and poverty alleviation in the country. Its aim was to achieve the target of electricity for all and the per capita availability of power of 1,000 kilowatt-hours (kWh) by 2012. However, this target was not met for a variety of reasons. Numerous challenges need to be addressed before India can achieve the desired national policy objectives. One of the most important concerns is that despite the 20-year reform process and private sector participation, the rate of resource augmentation and growth in energy supply has been less than the rate of increase in demand. Therefore, India continues to face severe energy shortages. The average per capita consumption of electricity of 704 kWh in India is a fraction of the global average of 3,240 kWh. Irrespective of the expected growth in demand for electricity in the coming years, significant capacity additions need to be made merely to bridge the current demand-supply gap. The peak demand is expected to be 218,209 megawatts (MW) in fiscal year (FY) 2016/17, compared to 97,269 MW of demand in FY2005/06.

The passage of the Electricity Act of 2003 was a signature achievement of the Indian power sector and demonstrated the intent to move away completely from the previous route of negotiated memoranda of understanding with investors to a market-driven situation. The latter would force potential investors to compete aggressively for generation (and later also transmission) contracts. The only two cases of distribution privatization (in the states of Orissa and Delhi) in India preceded the Electricity Act of 2003. The act provided for the appointment of any person (franchisee) to undertake distribution and supply on behalf of the licensee (state distribution utility) within the licensee's area of supply. This approach would, it was hoped, confer the benefits of private ownership through a concession arrangement, but not transfer actual ownership, which was controversial and resisted by most state political authorities. The introduction of reforms and competition under the Electricity Act of 2003 produced a significant private sector response in generation, a limited but respectable response in

transmission (because not many transmission lines were tendered in the first place), and a very limited response in distribution.

Private participation in generation therefore offers about a decade of experience before the Electricity Act of 2003 (1991–2002) and another decade since it was enacted (2003 to the present). A major criticism of the early independent power producer (IPP) policy (in the 1990s), and an illustration of how the risk was disproportionately borne by the public sector and consumers, was that few of the early IPPs were designed to meet peak demand even though that was the most pressing need at the time. Instead, contractual obligations of capacity charges and take-or-pay clauses forced the displacement of cheaper base-load power from state or central generation facilities in the early transactions. State electricity boards were relatively inexperienced because they had previously dealt with only public sector entities and thus were initially not adequately equipped to negotiate highly commercial contracts with private legal teams.

After the enactment of the Electricity Act of 2003, the negotiated approach for generation investments, through memoranda of understanding entitling the investor to a guaranteed 16 percent rate of return, began to be phased out. The act required all procurement of generation capacity to be undertaken exclusively through the competitively determined tariff method starting in January 2010. Both private generation investors and central and state sector generation investors had to go through competitive bidding to be awarded contracts after the January 2010 cutoff date.

The generation segment of the power sector value chain has witnessed the maximum interest from private players, which are primarily Indian companies. A few multinational players such as China Light and Power (CLP) and AES are in the Indian market, but their generation capacity is limited. Since the Electricity Act of 2003 and subsequent clarification of the regulatory framework, borrowing has been relatively easy for private firms, and their interest in the power sector has grown. Not only did private companies in the power and infrastructure sectors participate, but also companies in other sectors (noninfrastructure, but cash rich) displayed great interest in competing for contracts in the generation business. The bulk of companies in the transmission and distribution segments, however, are owned and operated by central and state government-owned entities, respectively.

Table O.1 shows the evolution of private sector generation capacity in MW and in percentage terms from 2006 to 2012. The capacity installed and owned by the central sector remained relatively stable over the period, showing only a slight decline. The capacity installed and owned by the state sector declined more sharply, from 53 percent to 43 percent, while private sector capacity grew almost threefold in terms of MW and slightly more than doubled in terms of percentages. Note that table O.1 shows a final total installed capacity of 199,877 MW as of the end of FY2011/12, whereas the total installed capacity stands at 211,000 MW as of the end of March 2012.

Despite the impressive addition of generation capacity during FY2006/07 through the present, the poor financial health of the power sector is most acutely

Table O.1 Installed Capacity of Indian Power Generation Assets

<i>Fiscal year</i>	<i>Megawatts</i>				<i>Share (%)</i>			
	<i>Central sector</i>	<i>State sector</i>	<i>Private sector</i>	<i>Total installed capacity</i>	<i>Central sector</i>	<i>State sector</i>	<i>Private sector</i>	<i>Total installed capacity</i>
2006/07	45,121	70,096	17,113	132,329	34	53	13	100
2007/08	48,361	74,689	20,011	143,061	34	52	14	100
2008/09	48,971	76,116	22,879	147,965	33	51	15	100
2009/10	50,993	79,392	29,014	159,398	32	50	18	100
2010/11	54,413	82,453	36,761	173,626	31	47	21	100
2011/12	59,683	85,919	54,276	199,627	30	43	27	100

Source: World Bank 2012.

exposed in the distribution segment, where revenues enter the system at the customer interface. The revenues collected from customers should be adequate to cover all costs incurred along the value chain before final delivery to the end user, that is, the costs of bulk power purchase, transmission, distribution, and retailing (metering, billing, and collection). In practice, large amounts of power that have been purchased and paid for by the distribution company (discom) are stolen, and therefore revenues cannot be recovered for those units of power although costs have already been incurred. In addition, the power grid is in disrepair as a result of years of neglected maintenance and causes a portion of the purchased power to be undeliverable to the customer because of technical losses arising from the poor physical condition of the network. Finally, a practice of providing free, unmetered power to agricultural users exists in many states, although this amount of power consumption is unlikely to account for the major share of unaccounted-for power. The discom purchases the power and seeks to recover revenues from sales to its final customers. In some cases, the unit rate at which it bills its customers is lower than the unit rate at which it purchases power, particularly from private power suppliers. This disparity creates a built-in loss even if the discom could account for every unit. Furthermore, a large portion of the power is stolen or otherwise lost and can never be billed. This is the major reason that discoms are dependent on state subsidies to remain afloat and that despite large injections of subsidies, they are still sometimes unable to repay their commercial bank loans.

Most states have not succeeded in enforcing strict mechanisms to reduce distribution losses and curb theft of electricity. In addition, there is a pervasive lack of commercial culture or any sense of commercial pressure; no one is personally accountable for spiralling losses and poor operational efficiency in the bureaucratic setup that defines the operating environment of the state-run power sector. Over one-third (35 percent) of the volume of power purchased by a distribution utility is typically lost and never billed to the final customer, or at least the utility can never account for such revenue. These losses are the aggregate technical and commercial (AT&C) losses, which in India are among the highest in the world.

Clearly the distribution segment is in the most urgent need of the commercial focus and management practices that come through private participation. Yet, possibly primarily related to political interference from the state level (that is, possible condoning of some of the rampant power theft by large industrial customers who are well connected to state authorities), the distribution segment continues to remain in the stranglehold of state-owned utilities with compliant management that is not averse to obeying orders from politicians. Tepid attempts at introducing a commercial focus via limited private participation through franchising of electrically ring-fenced areas have yielded modest results, though they have made important differences in some urban areas where they have been successfully introduced. Nonetheless, franchising has not yet been attempted on a scale that can have a transformative effect. However, this book presents the lessons to be learned from the successes and failures of the handful of franchising attempts over the past few years, with a view to improving future success rates of such private involvement in distribution.

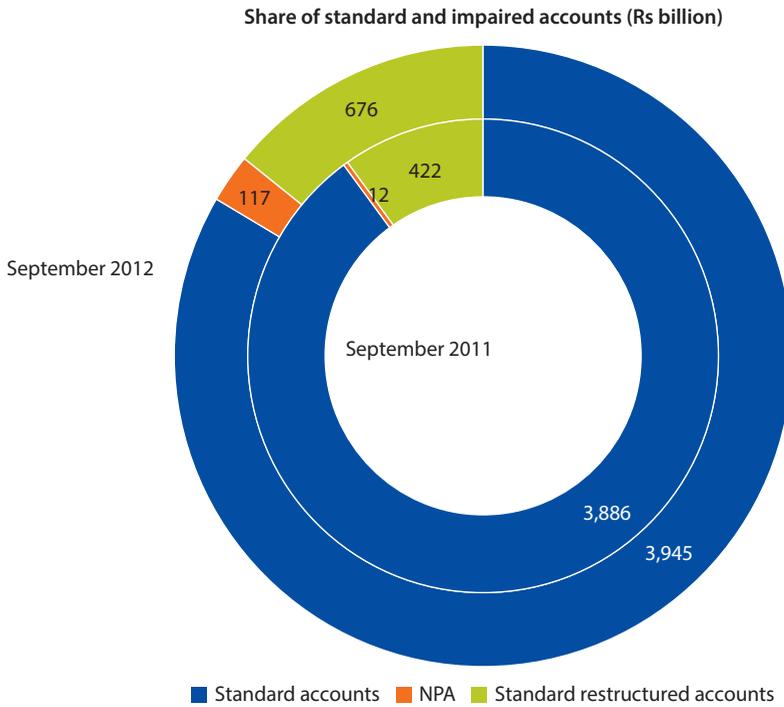
Distribution segment finances have continued to worsen considerably to a level that has been characterized at times as “India’s subprime crisis.” Especially from 2008 to 2013, the problem has attained mammoth proportions with the annual financial gap now at US\$20 billion before subsidies. Even after one considers subsidies paid out to utilities from the State Exchequer (often not paid on time), the deficits are US\$7 billion annually, which means the financial deficits of the distribution segment before subsidies are equal to more than half the aggregated annual budgets of the states of Uttar Pradesh, Maharashtra, Rajasthan, Madhya Pradesh, and Bihar, five of India’s most populous states. The poor shape of finances has several adverse effects, resulting in poor quality of supply on the one hand and inadequate capacity utilization on the other hand in generating stations, because distribution companies lack the purchasing power to buy enough power from generating stations. This further affects sector finances and requires ever-increasing subsidies.

The distribution segment’s losses threaten to derail the power sector and also jeopardize the health of the financial sector, given the high level of commercial bank exposure to power sector risk. The banking sector’s exposure to the power sector has continued to increase in absolute terms, and nonperforming assets (NPAs) increased nearly tenfold between September 2011 and September 2012, from Rs 12 billion to Rs 117 billion, as illustrated in figure O.1.

The growing number of NPAs in the power sector has a number of implications. Among other side effects, it is likely to have accounted for a decrease in commercial lending to the power sector and possibly a long-term reduction in the commercial lending appetite for power sector assets. Figure O.2 illustrates the decrease (see “Infrastructure” in figure O.2).

The macroeconomic outlook beyond 2012 is challenging, and the private sector will increasingly be competing with the government to access declining public savings. The Reserve Bank of India conducted a sample study of 12 corporate entities with high exposure to infrastructure, particularly power, and found (a) sharply increased ratios of debt to equity and debt to earnings before interest,

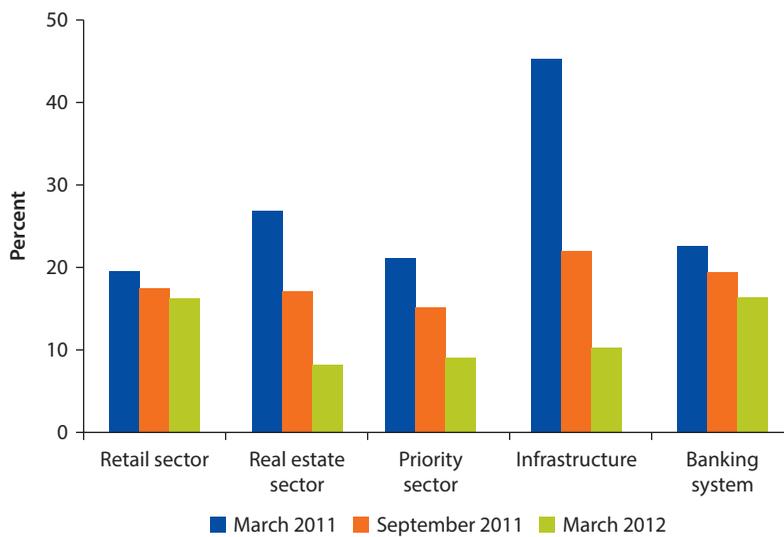
Figure O.1 Bank Exposure to Power Sector



Source: RBI 2012, 32.

Note: NPA = nonperforming asset.

Figure O.2 Growth Rate of Bank Credit to Select Sectors



Source: RBI 2012, 32.

tax, depreciation, and amortization and (b) decreasing interest coverage. These findings point to increasing vulnerability of both the corporate entities and their lenders (table O.2).

Over the past decade, the reaction of the central government to the financial crisis in the distribution segment has been rather muted, although at least two centrally funded no-strings-attached bailouts have been offered to state utilities—in March 2001 and September 2012. Finally, as of March 2013, the Ministry of Power has undertaken leadership on this issue and has released a rating of distribution utilities' financial health to help lenders assess the risks of specific distribution utilities. Utilities have been rated on the basis of seven parameters including financial status and compliance with regulatory norms. The integrated ratings shown in table O.3 use an annualized basis and range from A+ to C (A+ is best, and C is the minimum). The total score is 100.

The integrated grading scale of A+ to C is *different* from the existing, standard rating scale adopted by credit rating agencies (AAA to D), because the standard credit rating measures only the degree of safety for timely servicing of financial obligations *based on probability of default*. In contrast, the integrated grading exercise shown in table O.2 analyzes the operational and financial health of the distribution entities on the basis of the rating framework approved by the Ministry of Power. Furthermore, the standard credit rating for distribution utilities entails comparison with nonspecific "other corporates," whereas the Ministry of Power's newly developed integrated rating exercise is based on a comparison of the entity with other distribution utilities only.

Table O.2 Causes for Increasing Vulnerability of Corporate Entities

<i>Element in decline</i>	<i>Element on the increase</i>
<ul style="list-style-type: none"> • Household savings • Growth 	<ul style="list-style-type: none"> • Inflation • Current account deficit • Rupee depreciation

Table O.3 First Integrated Rating for State Power Distribution Utilities, March 2013

<i>Score distribution</i>	<i>Grade</i>	<i>Number of utilities</i>	<i>Grading definition</i>
Between 80 and 100	A+	4	Very high operational and financial performance capability
Between 65 and 80	A	2	High operational and financial performance capability
Between 50 and 65	B+	11	Moderate operational and financial performance capability
Between 35 and 50	B	10	Below average operational and financial performance capability
Between 20 and 35	C+	8	Low operational and financial performance capability
Between 0 and 20	C	4	Very low operational and financial performance capability

Private investors in generation need to be concerned about the financial health of discoms, because discoms are their customers. The primary source of revenue for discoms to purchase power comes from their ability to efficiently collect revenue from delivery of power to end users. Revenue shortfalls are supplemented by subsidies from state coffers, but this practice is unsustainable over the long term. Discoms must improve revenue collection practices by cracking down on theft and repairing obsolete networks or seek approval of the state regulator to charge end users a retail tariff that is closer to the cost at which they are purchasing power, or both. Despite all the caveats and concerns about discom financial health, one must recognize that the 11th Five-Year Plan (2007–12) coincided with a period of buoyant economic growth in India, a stock market bubble, record tax collections, and high levels of government support to the power sector. In addition, the highest-ever rate of private participation in the power sector occurred, as well as the highest-ever achievement of total generation capacity addition over a five-year period (52,000 MW for the central and state government sectors and private sector combined).

An analysis of private participation in the Indian power sector would not be complete without considering the National Solar Mission (NSM), and the remarkably high levels of private participation (including from international investors) attracted to central and state government efforts to increase solar generation capacity. The NSM, headed by the Ministry of New and Renewable Energy, was launched in January 2010, when the Indian solar energy market had a capacity of only 17.8 MW. By March 2012, the cumulative capacity had grown to 506.9 MW. Of this capacity, 203.4 MW was commissioned under the NSM and other central government schemes. Another 303.5 MW was deployed under initiatives of various states. The targets are bold: the NSM seeks to install 20,000 MW of grid-connected solar power by 2022. Qualifying projects, sourced from private sector investors, are selected through a reverse auction procurement mechanism and are ostensibly technology neutral, employing either solar photovoltaic or solar thermal technology.

Eight states have participated in phase 1 installations (photovoltaic and solar thermal) of the NSM, with Rajasthan by far in the lead in terms of allocations (table O.4). However, Rajasthan's state-level incentive program has been suspended because of worsening financial conditions of the state utilities and doubts about their ability to pay private developers. (The NSM offers the advantage of bundling the solar cost with the thermal power cost and making the blended price more affordable for utilities to purchase.)

Making news headlines in late 2011, competitive bidding for the NSM's second batch of projects in phase 1 drove prices for grid-connected solar energy as low as Rs 7.49 (US\$0.15) per kWh, approaching grid-parity with fossil fuel-powered electricity. Phase 1 also attracted large conglomerates and new players into the solar market. During the mission's first phase, more than 500 bidders competed for 63 projects allocated during two reverse auctions, driving prices to a record low. New solar energy investments in India increased to more than Rs 12,000 billion (US\$2.5 billion) in 2011. This was in a general context of

Table O.4 Allocations of State Capacity under the National Solar Mission
Megawatts

State	Batch 1 (2010–11)	Batch 2 (2011–12)
Rajasthan	PV: 100 ST: 400	PV: 295
Gujarat	ST: 20	—
Maharashtra	PV: 5	PV: 25
Karnataka	PV: 5	—
Tamil Nadu	PV: 5	PV: 10
Andhra Pradesh	PV: 15 ST: 50	PV: 20
Orissa	PV: 5	—
Uttar Pradesh	PV: 5	—

Source: CEEW and NRDC 2012.

Note: PV = photovoltaic; ST = solar thermal; — = not available.

investments in the overall renewable energy markets in India reaching approximately Rs 51,000 billion (US\$10.3 billion) in that year, that is, solar projects accounted for about one-third of the overall investments.

In conclusion, the road to full financial recovery of discoms and high performance of the power sector as a whole remains long. Much has been learned on the way, and many adjustments and modifications have been admirably made. New adjustments are needed to deal with the fossil fuel risks (coal and gas shortages) that have recently emerged and to make better use of private service delivery and new technologies to reduce losses in power distribution. The most important challenges—of providing governance and leadership and of reaching consensus that the power sector should not be treated as a source of political patronage—remain entirely homegrown. There is no imported expertise or technique or reform model that can expedite such political will. Once the political will is in place to fix the “leaking bucket,”¹ in the memorable words of Shri Deepak Parekh, there will be no holding back the power sector. Enough capable and experienced private investors, capital, and expertise are poised to propel the sector forward into the 21st century and put wind in the sails of India’s overall economic growth.

Lessons Learned from Two Decades of Efforts to Attract Private Investment in the Power Sector

What Worked Well in the Indian Power Sector Experience with Private Participation?

With respect to private participation in the power sector in India, the following worked well:

- *The reform process to attract private investors has been evolutionary and has involved “learning by doing” rather than importing any wholesale approach.* Indian states and the central government have attempted to attract private participation through a continuously evolving and action-learning process, starting with

the IPP policy of the early 1990s, which sought to attract new generation investments. The incentives initially offered to potential investors were perhaps overly generous, but ultimately, few companies were able to take advantage of the incentives because of checks and balances contained in a massive bureaucracy. Investors were required to obtain approvals and clearances from numerous ministries that were not necessarily eager to extend special treatment to IPP investors. The unraveling of the Dabhol-Enron power project was a major learning experience for Maharashtra and the rest of the nation. IPPs with take-or-pay clauses would not be allowed to displace lower-cost base-load power procurement arrangements already in place with state and central government generators. No sovereign counterguarantees would be offered again to fast-track projects.

- *Leadership on sector reforms and improvement of distribution performance has come from various initiatives by states governments (Delhi, Maharashtra, Orissa, and others) as well as the central government (Electricity Act of 2003).* Orissa and Delhi privatization experiences are other clear examples of learning by doing and letting future actions be informed by lessons of experience. The Orissa privatization divested entire, large, mixed-load utilities (with external support and timetables to be followed), whereas the Delhi privatization divested parts of an urban utility over a relatively compact customer base into smaller geographic territorial boundaries. The Delhi privatization was done without external support, in a manner that suited the authorities and allowed them to provide discreet transitional support to the winning bidders who had been selected on the basis of their commitment to acceptable loss reduction trajectories. The focus had shifted from simple divestiture of government ownership in Orissa to loss reduction in Delhi and from no transitional support in Orissa to an offer of front-loaded transitional support in Delhi that was designed to phase out as efficiency gains kicked in. These are concrete examples of lessons learned and applied.
- *Passage of the Electricity Act of 2003 was a signature achievement of the Indian power sector and demonstrated the intent to move away completely from the previous route of negotiated memoranda of understanding with investors to a market-driven situation that forced potential investors to compete aggressively for generation (and later also transmission) contracts.* On the basis of the provisions of the act, several policy initiatives were implemented by both central and state governments. The National Electricity Policy, issued by the central government in February 2005, had among its objectives making power available to all households in a period of five years. It also provided guidelines for the commercial turnaround of utilities and protection of the consumer interest. The National Tariff Policy of January 2006 had the objective of ensuring financial viability of the power sector and attracting investments, as well as promoting transparency, consistency, and predictability in regulatory approaches across jurisdictions. Other key initiatives at the central government level include the Rural

Electrification Policy. The state electricity regulatory commissions have also issued their own policies and directives in compliance with the provisions of the Electricity Act of 2003 and other policy initiatives.

- *Private investment in generation under the market-driven competitive bidding scenario did well in the 11th Five-Year Plan (2007–12), and the initial rounds of bidding coincided with a booming economy and a stock-market bubble in which private companies responded in large numbers.* Therefore the competitive bidding rounds resulted in extremely low tariffs being quoted by the private sector and illustrated a very high value for money resulting from the competitive route as opposed to the negotiated route. (In some cases, companies bid too aggressively and are now locked into long-term power purchase agreements [PPAs] that they will be unable to execute owing to a spike in fuel costs, because their hedging arrangements have unraveled as a result of regulatory changes in Indonesia and Australia. This issue remains unresolved, but it raises doubts about whether some of the triumphs of the 11th Five-Year Plan's best deals in terms of lowest bids for multiyear power purchases can in fact ever materialize fully over the 25-year life of the PPA.) Nevertheless, about 27 percent of installed capacity addition is now financed and owned by the private sector, according to competitively awarded contracts, and this is a positive testament to the ability of the government to engender enough confidence in the private sector to invest in generation.
- *Competitive bidding for transmission projects is now the default mode for project execution at both the interstate and the intrastate level.* Two models currently are being used to solicit private participation in transmission: the Ministry of Power model and the Planning Commission model. There are some similarities in the models. Under both models, the private investor arranges financial resources and undertakes construction, maintenance, and operation of the transmission line for an annual transmission charge paid by the beneficiary. This approach suggests that the private investor assumes all project-related risks. However, in terms of eligibility requirements (qualifications of bidders), there is a difference in the way both models treat interested private investors. Whereas the Ministry of Power model does not consider experience in transmission projects to be one of the requirements, the Planning Commission model provides a benefit to private investors who have previous experience specifically in transmission. Once construction is complete, both models also require the private investor to be responsible for the operation and maintenance of the project, though this function can be undertaken by the private investor or a third party hired by the project developer. The major difference is that the private sector retains ownership of the transmission line in the Ministry's model (build-own-operate-manage [BOOM]) whereas the asset is transferred back to the state in the Planning Commission model at the end of a pre-agreed period, such as 20 years (design-build-finance-operate-transfer [DBFOT]).

- *The Central Electricity Regulatory Commission (CERC) has shown leadership in modernizing the transmission sector's operating environment.* A major intervention by CERC during the 11th Five-Year Plan, in pursuit of relieving congestion on the grid, included framing of regulations on point-of-connection transmission charges. This action sought to introduce a scientific approach to transmission tariff determination, based on distance, direction, and quantum of power flow and corrected the shortcomings of the earlier “postage stamp” methodology of allocation of transmission charges among different users.
- *Ultra mega power plants (UMPPs) introduced the relative allocation of tasks in the true spirit of a public-private partnership.* UMPPs, or very large coal-fired power plants generating 4,000 MW or more and using advanced high-efficiency technology, adopted a novel approach to the preconstruction tasks that recognized the relative comparative advantage of the public sector over the private sector in certain areas. The UMPP approach consists of forming a special purpose vehicle (SPV) company that has completed tasks requiring intragovernment coordination such as securing permits, clearances, licenses, and even large tracts of land. Shares in the SPV are then auctioned as part of the bid process, which also contains the levelized tariff as a bid variable. The winning bidder acquires the SPV and begins with a company that has already completed the time-consuming steps involved in up-front project preparation that can often take 18 months or more. In this manner, the private party is able to proceed immediately with activities that correspond to its core competence—design; construction; project management; commissioning; and operations, maintenance, and management.
- *The success of the Bhiwandi franchisee in both the steep loss reduction achieved by Torrent Power Ltd. and the improvement in quality and reliability of supply under the franchisee model has encouraged several utilities and states to undertake such initiatives in areas where the licensees have been struggling to improve efficiency levels.* The distribution franchisee model has evolved since the Bhiwandi model was implemented with only the key terms of the distribution franchisee agreement on hand at the stage of bidding. The distribution franchisee agreement under the present model is more like a management and outsourcing contract because the ultimate responsibility for the area still remains with the licensee. Also, the competitive bidding process by the franchisee affects only the efficiency levels and recovery of the licensee, which continues to file its annual revenue requirement and tariff petition as usual for its overall license area, regardless of whether a distribution franchisee has been appointed. Thus, the distribution franchisee is virtually nonexistent for the regulator with respect to the routine business scenario.
- *The National Solar Mission has rapidly added on-grid solar capacity and has attracted very widespread private sector interest, with sharp drops in tariffs resulting from highly competitive reverse auctions.* For both batches of phase 1 of the

NSM, the central government used the reverse auction as a price discovery mechanism. Reverse auctions have two main benefits. They allow government procurers to select projects based on lowest cost (thereby keeping the burden on fiscal resources and taxpayers low), and they ensure that a price-based selection process will be fair and transparent. Project developers bid on discounted tariffs set by the CERC. A 5-MW parcel-size requirement for batch 1 and a 20-MW maximum parcel-size requirement for batch 2 opened the market to allow a broad range of companies to enter the sector, as long as they met the criteria set out in the guidelines.

In late 2011, competitive bidding for batch 2 projects of phase 1 of the NSM drove prices for grid-connected solar energy as low as Rs 7.49 (US\$0.15) per kWh, which approached grid-parity with fossil fuel-powered electricity. Large conglomerates and new players were attracted to the solar market in phase 1 also. In that phase, more than 500 bidders competed for 63 projects allocated during two reverse auctions, which drove prices to record lows. New solar energy investments in India increased to more than Rs 12,000 billion (US\$2.5 billion) in 2011.

What Worked Less Well in the Indian Power Sector from 1992 through 2012?

With respect to the power sector in India from 1992 through 2012, the following worked less well than anticipated:

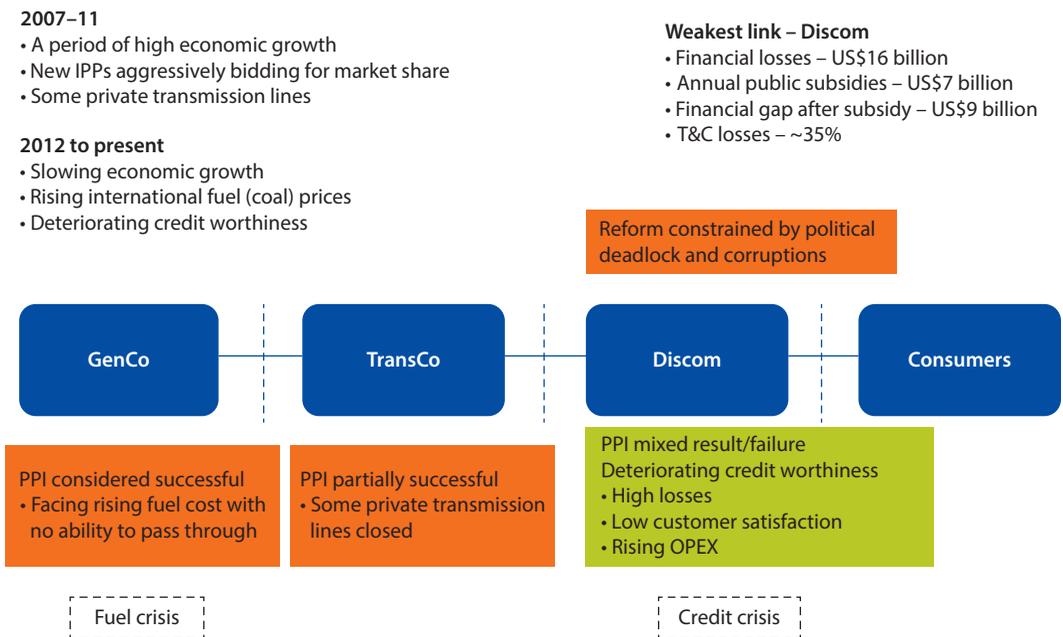
- *Distribution losses have not been adequately addressed over time and are now harming the sector's growth prospects, because other stakeholders' risk perceptions about the ability of utilities to pay for power purchases are causing them to hold back.* The critical importance of distribution reforms has become clear over time, because a utility's revenues to pay for power purchases from private generators are collected through the distribution segment. When distribution utilities incur massive losses, and remain dependent on subsidies from the State Exchequer to pay private investors for power, a point comes when private investors and their commercial lenders reach their risk tolerance threshold and retreat to the sidelines. This response may be in progress at the moment; after the flurry of private investor response to tenders for power generation in the 11th Five-Year Plan, very few new transactions were recorded in 2012. (There are also other reasons for the current lack of private investment in generation, which are discussed further below.)
- *Postponement of distribution reforms while losses have skyrocketed in almost all states has occurred because of the lack of commercial pressures in the state bureaucracy, of which the distribution utility is a part.* Use of the distribution franchisee approach to address the ills of the distribution segment has been notably muted, and very few states that have tried have successfully awarded urban franchises for ring-fenced portions of their distribution networks. Most states have failed in enforcing strict mechanisms to reduce distribution

losses and curb theft of electricity, and a commercial culture or any sense of commercial pressure is absent because there is no personal accountability for the increasing losses and poor operational efficiency in the bureaucratic framework in which the state power sector operates.² More than 35 percent of the volume of power purchased by a distribution utility is frequently lost in some states, and never billed to the end user; for whatever reason, the utility cannot account for that lost revenue. These are the aggregate technical and commercial losses, of which India has some of the highest in the world.

- *Rural access is increasing but not through any large-scale investment efforts by the private sector.* Private involvement in rural electrification has been confined mainly to revenue cycle management and use of private parties for outsourced metering, billing, and collection. A few pilot business models for the private sector have been demonstrated to be commercially viable in the off-grid space, through innovative combinations of renewable energy technology and information technology applications to increase the span of control over multiple power generation sites and to manage demand through mobile phone communication with customers, smart payment systems, and other demand-responsive features. However, these business models, although very encouraging, are still in an early stage of development.
- *Load shedding in the face of both power shortages and customers who are willing to pay but cannot purchase the power from private suppliers is a clear warning sign that resources are not being allocated efficiently.* The only channel in which buyers and sellers of power can meet is the inefficient state discom, because state regulators have not done their jobs in implementing open access that would allow private investors to bypass the discom and sell directly to large customers. When the state discom has no money to buy available power, the power is simply shut off along feeder lines going to customer premises, and customers must deal with a blackout, or incur very high costs of generating captive power. So private generators exist, who would be able to sell power directly to large users through a bilateral contract under the open access arrangement, which is also allowed under the Electricity Act. This is not happening in practice, however. Discoms are afraid to lose their large customers who cross-subsidize the residential customers. They impose financial penalties (known as the “cross-subsidy surcharge”) on industrial customers wishing to purchase power directly from private generators, in order to make it prohibitively expensive to leave the discom. Inefficiencies are compounded on all sides.
- *The lack of distribution segment reforms is the glaring gap in the value chain.* Almost all attempts to attract private investment in generation have been made in the absence of distribution segment reforms, most likely because of the political sensitivities associated with such reforms. Sensitivities include, for example, measures for loss reduction, which in turn require the utility to disconnect practitioners of electricity theft (who may be politically powerful); the

introduction of retail tariff increases before power supply improvement can be felt by long-suffering customers, which may lead to defeat of the incumbent political party if elections are looming; or the necessity of making metering investments in the network for which the utility does not have the funds. As noted several times above, the distribution segment is the power sector’s interface with the final customer. This is the last mile—entering customer premises and collecting customer revenues, which will be used toward covering all costs of power delivery incurred up to the point where power reaches the final user. It is also the segment where governance concerns are often legitimate. (For clarification, the rational decision making by utility heads that was referred to earlier is not a *governance* concern in that sense. Instead, the governance concern here is political patronage using electricity as the handout. Many state politicians use electricity for handouts and favoritism and issue instructions to the distribution utility to comply.) Political interference, high levels of losses and unaccounted-for power, and low levels of transparency about discom finances and subsidy allocations from state coffers persist. See figure O.3.

Figure O.3 Summary of Electricity Value Chain under Pressure



- High commercial and technical losses as well as low collection rates in combination with compromised political economy puts high pressure on DisCos. PPAs with IPP force dispatch of expensive plants, pressuring tariff. Attempts to bring private expertise delivered mixed results.
- The GenCos are facing financial pressure because of tight PPA tariffs and no pass through ability on rising fuel prices, while simultaneously facing reduced credit worthiness of DisCos.

Note: Discom = distribution company; GenCo = generation company; IPP = independent power producer; OPEX = operating expenses; PPA = power purchase agreement; PPI = private participation initiative; T&C = technical and commercial; TransCo = transmission company.

General Observations and a View Ahead

It is too early to comment on the ultimate success of the 11th Five-Year Plan rounds of competitively awarded power contracts, because most of the privately owned power plants and transmission lines are still under construction. Only one UMPP has been commissioned, and it is experiencing some hiccups (Tata Mundra). Other plants are beset by uncertainties about their commercial viability, after changes in the world coal markets have altered the cost assumptions built into very aggressively low-priced bids, as noted above.

Creditworthiness of the distribution segment is not only a power sector issue. It imposes systemic risks to banking sector stability. Several large public sector banks are heavily exposed to discom assets, because they have issued more than 80 percent of discom debt. NPAs have risen from Rs 12 billion to Rs 117 billion between 2011 and 2012. There are now real possibilities of cross-default triggered by the potential failure of big public banks with heavy discom exposure, if discoms do not receive adequate subsidies in time and default on their loans to these banks. It is not yet clear whether the centrally funded bailout of September 2012 has been effective, apart from postponing the immediate threat of defaults, nor whether it will be the last bailout required.

Without distribution segment reforms and a change of the underlying economics of the segment, the pattern of a central government-funded bailout for the power sector every decade looks set to continue. The first bailout (March 2001) was accompanied by unfulfilled promises from chief ministers to introduce metering, demand-side management measures, loss reduction investments, and increased basic rates for agricultural consumption—all in the form of a common minimum action plan.

The second bailout (September 2012) occurred in the face of a far greater exposure by private investors to power sector risk than did the previous bailout. This time commercial lenders and private equity investors were also involved, unlike in 2001 when no private parties had a financial stake. The 2012 bailout was quietly announced and implemented without any of the fanfare or public declarations and promises that occurred in 2001. Implementing regulations had not been fully worked out, and there may have been an element of panic that caused the announcement to be made prematurely (before knowing which states would participate), simply as a mechanism to address the risk perceptions of the commercial banks, which were starting to abandon the power sector. Yet the day of reckoning seems to have arrived, despite the announcement of the bailout to allow banks to address their exposure to the power sector. Now, without substantial introduction of reforms at the state level, particularly to improve governance of the distribution segment, the power sector likely will require a third bailout, probably much sooner than in another decade from now.

The current state of the Indian power sector is an acknowledged constraint to the country's growth aspirations. Power supply in India presents a chronic and acute problem that has refused to go away for the past several decades in spite of a range of policy actions. Going forward, adequate electricity supply will be

crucial to India's success in achieving its previously targeted annual gross domestic product growth of 8–9 percent.

Prospects for private generation investment in the Indian power sector since 2013 have looked less promising than they did during the economic boom of the 11th Five-Year Plan. The pinch is coming from both the generation and distribution segments; the transmission segment's difficulties are less serious by comparison. Three large red flags loom over the power sector for private investors at present, associated with the following:

- *Fuel risks* loom, as well as uncertainties related to both domestic and imported coal, because more than two-thirds of the Indian power sector meets its base load needs through coal-fired generation. Prices have spiked since 2011, while private investors are committed to competitively awarded 25-year PPAs, which affects commercial viability of plants still under construction. Originally there was no provision for a pass-through of fuel price increases. These are now permitted, on a limited basis, but given the financial difficulties of distribution companies, it is not entirely clear how the increased payments for power will be made.
- *Liquidity risks* and declining creditworthiness in the power sector exist because of poor distribution company finances, which affect all parties with exposure to distribution companies. How will distribution companies continue to be able to pay IPPs for power?
- A system of sector governance and *use of electricity for political patronage* in the state distribution utilities has changed little in three decades.

Notes

1. At the time (September 2001), Shri Deepak Parekh was Chairman of the Infrastructure Development Finance Corporation Ltd.
2. For example, utility managers have no personal accountability and no performance penalty for incurring operating losses, which are seen as the nationwide norm for the sector. They are employed at a utility for a limited rotation in their highly prestigious civil service career. They are also typically professional administrators and managers rather than technical specialists in utility matters, so they do not necessarily feel technically competent to sign off on the introduction of major process changes, such as deciding to upgrade from one metering system to another and signing off on all the training that would be required to accompany such a change. They do not want to risk labor unrest at the utility during their tenure. It is also likely that they will not be around to claim credit for future improvements to the utility's bottom line that may (or may not) result from any operational changes they may consider introducing during their tenure. The downside risk is high and immediate, in the sense of personal blame to be assumed if unrest, technology failure, or customer complaints arise from any changes introduced at someone's personal initiative. This is a brief conjecture on how the noncommercial culture at state utilities has resulted in total operating losses of US\$20 billion, before adjustments for various transfers from state coffers.

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Introduction to Private Sector Participation in the Indian Power Sector

This book reviews the major developments in—and the lessons learned from—the 21-year (1991–2012) experience with private sector participation (PSP) in the power sector in India. It discusses the political economy context of the policy changes, looks at reform initiatives that were implemented for the generation sector, describes transmission and distribution segments at different points in the evolution of the sector,¹ and concludes with a summary of lessons learned and a suggested way forward.

The evolution of private participation in the Indian power sector can be divided into different phases. Phase 1 was launched with the opening of the generation sector to private investment in 1991. Phase 2 soon followed—early experiments with state-level unbundling and other reform initiatives, including regulatory reform, culminating in divestiture and privatization in Orissa and Delhi respectively. Next came phase 3—the passage of the Electricity Act of 2003 by the central government, followed by a large increase in private entry into generation and forays into transmission and experiments with distribution franchise models in urban and rural areas during the 11th Five-Year Plan (2007–12) period. In phase 4, at the start of the 12th Five-Year Plan (2012–17), the sector is seeing a sharp reduction in “bid euphoria” and greater risk aversion on the part of bidders, who are concerned about access to basic inputs such as fuel and land. Before tracing the different phases of the reform process, we will begin with a brief assessment of the pre-reform period and consider the condition of the sector prior to its 1991 opening to private entry.

The Prereform Period: From Independence to 1991

At the time of India’s independence in 1947, private companies or local authorities accounted for more than four-fifths of the country’s total generation capacity of approximately 1,400 megawatts (MW). However, the Electricity Supply Act

of 1948 brought all new power generation, transmission, and distribution facilities under state purview.² This law resulted in almost every state and territory creating its own vertically integrated entity or state electricity board (SEB).

When they were first established, most SEBs operated as extensions of the states' energy ministries. They were indebted in perpetuity to the government because they were financially structured entirely through state government loans.³ The 1948 act gave tariff-setting authority to the SEBs.⁴ The act anticipated that the SEBs would function commercially and achieve a minimum 3 percent return on capital. Any operating losses incurred by the SEBs were to be covered through direct subsidies from the state exchequer; there was no provision for SEBs to incur financial losses.

The combination of structural inefficiencies introduced through political interference and forced subsidies required from SEBs without timely or adequate government compensation led to a situation in which most SEBs were often in serious financial trouble. The only way that many of them could meet their statutory requirement of 3 percent annual return on capital was through discretionary state government support. Because SEBs were already faced with serious cash flow problems, the governments often had no option other than to introduce cross-subsidies, such that industrial tariffs were high relative to the average or even marginal cost of supply to compensate for near-zero revenues from a growing agricultural sector (see box 1.1). Yet political considerations did not allow any

Box 1.1 The Green Revolution: Genesis of Free Power to the Agricultural Sector

By the late 1960s, India had launched the Green Revolution in its agriculture sector, which involved the widespread use of high-yielding crop varieties, with significant increases in inputs of water and fertilizer in fields that had hitherto been almost solely dependent on rainfall. In states such as Tamil Nadu and Punjab, this initiative meant that two or three crops per year could be harvested, thereby significantly raising farm productivity and profits. Many early irrigation projects were large and publicly funded, involving surface-water resources. However, groundwater pumping on individual farms using electrical or diesel pump sets became increasingly popular, especially in the 1980s. Irrigation of both forms was widely credited with significant increases in food production in the country. Irrigation had broad appeal because it seemed to be accomplishing two important political goals: achieving food security while increasing the profits of farmers, who could thereby be organized into large vote blocs. Politics were indeed quite crucial in determining events related to the power sector in this period, and subsequently they led to a type of institutional lock-in (free power to farmers) with profound effects on the sector.^a

a. Although the political claims for many agricultural power subsidies are typically made on behalf of poor farmers, several studies confirm that the constituencies at stake are the *kulak*, or landed classes, to whom the bulk of the subsidies are directed. The *kulak* are the classes most likely to invest in irrigation and either use the surplus water to grow high-value crops or sell it to other farmers (Sant and Dixit 1996).

significant withdrawal of subsidies for nonindustrial customer categories, for which political control over SEBs was essential.

Cross-subsidies undoubtedly caused disaffection among industrial consumers who finally found it expedient to set up their own captive generation plants to supplement, if not replace, grid supply, which was also becoming increasingly unreliable. Thus, although industrial consumption had constituted nearly two-thirds of total SEB sales in 1960, by 1991 its share had dwindled to about 40 percent. This decline occurred not only because agriculture experienced rapid growth (its share jumped from about 10 percent to 25 percent), but also because many industrial consumers had cut back on their consumption from the grid and were now supplying themselves. The net result was that cross-subsidies from industrial consumers were not sufficient to compensate for a shortfall in revenues, and SEB financial health went into decline.

Other operational problems appeared as high technical and commercial losses (the former arises from a poorly maintained network and the latter is a euphemism for theft). Also, because many connections that were subsidized were also left unmetered, a growing gray area of the sector was using power but not paying for it. It is important to clarify that most of the theft was occurring outside of the agricultural customer category (often by very large and well-connected industrial consumers), mostly with the connivance of SEB workers who, in turn, claimed that they were being pressured by high-level authorities of the states' political machineries. Unaccounted-for power had risen to between one-third and one-half of the power entering the distribution network by the 1980s; this was power that had been purchased by the SEB from the generator but was lost before revenues could be collected for it from the end user.

By 1991, SEBs controlled more than 70 percent of power generation and virtually all distribution. For some time, broad consensus had been emerging that the power sector was in dire straits and that major reforms were needed to change the way it functioned. There were peaking shortages in many parts of the country, severe financial burdens were being imposed on state governments because revenues did not match costs, and everyone was experiencing the same poor quality of supply from the public grid. This situation, then, was the pre-reform scenario in the Indian power sector.

Phase 1 (1991–95): The Opening of the Sector to Private Investment in Generation—Independent Power Producer Policy

The macroeconomic crisis of 1991 precipitated remarkable external and internal pressure to deregulate, if not privatize, major segments of the economy that had been tightly controlled for nearly a half century under independent democratic governance following colonial rule. For the power sector, reform began in October 1991, when the Ministry of Power (MOP) of the government of India

began to publish a series of notifications seeking to encourage the entry of privately owned generating companies into the electricity sector.

It is important to note that the 1991 power sector reform sought only to add generation capacity and bring more power into the sector,⁵ despite the unsatisfactory underlying performance of the sector as a whole. From the states' viewpoint, the critical problem that needed to be addressed was the peak deficit that led to power shortages and rationing. These government orders at the start of the reform, some of which were later enacted in Parliament to become the Electricity Laws (Amendment) Act of 1991, radically revised prevailing legislation by permitting private entities to establish, operate, and maintain generating power plants of virtually any size and to enter into long-term power purchase agreements (PPAs) with SEBs who remained in charge of distributing power to end users.

The initial government notification also provided generous incentives to these independent power producers (IPPs), the most noteworthy of which was a guaranteed minimum 16 percent (repatriable) return on equity (in any currency) for plants that operated at their rated capacity for at least 6,000 hours in a year (of a total of 8,760 possible hours), with additional bonuses for improved capacity utilization. Other attractions for potential investors included a five-year tax holiday, a two-part tariff (the first part covering fixed costs, including the assured return, and the second covering variable costs), equity requirements as low as 20 percent of project costs, and selective counter-guarantees from the central government to cover payment default by SEBs. The rules were clearly intended to attract foreign private capital into the sector, because they allowed for 100 percent foreign equity but insisted that Indian financial institutions provide no more than 60 percent of the total debt component of any given project. In a typical transaction in which equity would cover only 20 percent of project costs, and the remaining 80 percent would be financed through debt, Indian banks could meet at most 60 percent of the 80 percent debt requirement, and foreign lenders would have to cover the remaining 40 percent.⁶ The Indian project sponsor would have to be strong enough to attract foreign commercial borrowing of 28 percent of project cost in this illustrative example. The rules did not allow Indian bankers to fund all of the debt in these early days of IPPs.

The response to the incentives offered was overwhelming from both domestic and international investors. By mid-1995, there were about 189 offers to increase capacity by more than 75 gigawatts, involving a total investment of more than US\$100 billion. Of these, 95 projects for a total installed capacity of 48,137 MW had reached the stage of memoranda of understanding (MOUs) or letters of intent (LOIs) with state governments. To help these projects reach financial closure, the central government introduced another set of carrots by granting fast-track status to eight of the most promising projects and agreeing to offer them sovereign counter-guarantees. For all the excitement with which it was launched, the reform program turned out to be a dud overall: against a target of more than 40,000 MW in the 8th Five-Year Plan period (1992–97), fewer than 17,000 MW were added.

In the course of trying to implement the 1991 IPP policy, the government lacked coordination between the MOP and other agencies. Investors frequently confronted what they considered to be the recalcitrance of other government departments, but this lack of coordination would be defended by officials as a well-established, if complex, network of rules relating to fuel security, import policy, environmental protection, and the like. There were also instances in which the legacy of older institutions hindered IPP development. For example, the IPPs found it complicated to secure contracts for Indian coal because the vertically integrated SEBs had traditionally defaulted on payments to public companies managing coal and railways. Neither the Ministry of Coal nor the Ministry of Railways was willing to change its procedures radically to accommodate IPPs, because the ministries continued to perceive payment risks. However, many IPPs preferred to seek imported fuel for their projects, in spite of import tariffs, because fuel costs were typically passed through to SEBs purchasing power from them. Without going into further detail, it is clear that IPP developers found themselves confronting an array of government agencies that were stakeholders, but were not themselves promoters of the IPP policy. This situation may account for the fact that such a small percentage of IPP investment targets was actually achieved in phase 1.

Meanwhile, commercial lenders who had been cautious about the bankability of projects, but who were generally satisfied as long as sovereign counter-guarantees were offered, began to seek new ways to finance IPP projects when the central government announced that these guarantees would be limited to only the fast-track projects. Lenders clearly understood that the long-term viability of the new arrangements would depend on stable revenue streams from distribution. They began to seek mechanisms such as escrow accounts for prime distribution areas, limited debt guarantees from multilateral donors, even pursuing (unsuccessfully) use of the Power Grid Corporation of India Ltd. as the prime purchaser to manage and consolidate creditworthiness concerns and, ultimately, started to advocate for the restructuring of SEBs. Escrow quickly began to be seen as the most attractive of these options, allowing lenders to ring-fence revenue streams of SEBs and place a first charge on cash flows that would repay the loans the lenders had extended to IPPs. Against the objections of several planners and bureaucrats who were concerned about the further burden on SEB creditworthiness this would involve, several state governments that wished to satisfy requirements of commercial lenders began to set up escrow accounts for IPPs. However, that too reached its limit very quickly, when those governments realized that most SEB revenue streams were too thin to support escrow requirements of all the IPP projects that were seeking to come on line.

Despite the substantial policy changes and intent demonstrated by the central government, only three of the eight fast-track projects were ever commissioned.⁷ Among these three projects was the first phase of the gas (regasified liquefied natural gas [R-LNG]) Dabhol Power Project, which was planned despite the questionable economics of an R-LNG-based base load power plant in Maharashtra. By the mid-1990s, Enron's Dabhol Power Project had run into several issues with the state government,⁸ with opposition parties in Maharashtra alleging

irregularities and high power tariffs being locked in immediately after the signing of the PPA with the SEB in 1993. After the ruling party was voted out of power in the state's general elections in 1995, the terms of the PPA were renegotiated with Enron in a hostile environment of mutual suspicion. When phase I of the plant was commissioned and the plant started supplying power in 1999, the SEB and Dabhol traded charges over the exorbitant cost of power. Ultimately, the Maharashtra SEB (MSEB) stopped payments to Dabhol in 2001 and sought to cancel its PPA. The Dabhol Power Project marks a watershed in the sector reforms started in 1991.

What were the main lessons of phase 1 of the Indian power sector reforms? The government announced very generous incentives to IPPs and received an enthusiastic response, but may not have initially realized the implications of some of the IPP clauses such as "take or pay." This clause was the source of the problem with power procurement for base load. IPP power is much more expensive and therefore better suited to peaking power requirements, than other alternatives that were previously used for base-load (such as lower-cost state power generation plants or efficiently run large-scale National Thermal Power Corporation power, both of which are cheaper than privately generated power for SEBs). However, to guarantee the IPP investor all the generous financial returns that the IPP policy promised, SEBs would have to buy "all IPP power, all the time," and stand down cheaper base-load plants in order to fulfil their financial commitments. The Dabhol Power Project experience showed that if SEBs believed power costs were too high, a point would come when sanctity of contracts was no longer observed. This realization conveyed a chilling message to other IPP investors, present and future. A major criticism of the early IPP policy, and an illustration of how the risk was disproportionately borne by the public sector and consumers, lay in the fact that few of the IPPs were designed to meet peak demand even though that was the most pressing need of the time. In Maharashtra, the Enron-Dabhol project constituted surplus capacity in the state, and the dilemma for the SEB was how to sell the excess power it had been obliged to buy at very high rates to neighboring states in order to recover losses. SEBs did not have adequate legal and commercial support to enter into negotiations on internationally binding PPAs.

Phase 2 (1996–2003): Restructuring of SEBs, Introduction of Sector Regulators, and Initial Attempts at Privatization in Orissa and Delhi⁹

The call for SEB reforms, though largely unheeded, did not fall on entirely deaf ears during the IPP policy phase. Yet power sector restructuring in India in the mid-1990s was a trip into uncharted waters; restructuring had never been done at the state level, and the central level may have been unprepared to deal efficiently with the complex questions for which it had responsibility. As such, although the basic ingredients of the restructuring model were fairly simple—horizontal and vertical restructuring, privatization, competition, and regulatory reform were well established by then as international best practice of the

time—the state and national contexts in which the reform would be implemented were complex, challenging, and capacity constrained.

It was against this background that, in 1996, the Orissa state government initiated a comprehensive reform and restructuring of the power sector. At the time, the Orissa SEB was the worst-performing SEB of any major state. Blackouts and brownouts were common, and only about 20 percent of the households in the state were connected to the grid. The power sector was a major fiscal burden on the state, and inefficiency, losses, and corruption were endemic. Orissa became the first Indian state to embrace what was then a new and bold power sector restructuring model for India. There was high political commitment: the political leadership had repeatedly emphasized that privatization was inevitable; the only factor to determine was how the transition could be made smoothly. The World Bank supported the reform process through a US\$350 million assistance package.

With the establishment of the Orissa Electricity Regulatory Commission (OERC) in 1996, Orissa became the first state in the country to create an independent regulatory body in the electricity sector that was responsible for regulating and determining tariffs for the sector. In many ways, the formation of successor entities to an unbundled, consolidated SEB through the issuance of statutory transfer schemes by the state government, together with the creation of OERC, were significant contributions to the sector in India. These steps would later be adopted as a tested basis for staff member transfers, formation of electricity regulatory commissions, and so forth, and were finally adopted as part of the Electricity Act of 2003. Following Orissa's experience, many states adopted similar reform approaches. Assam, Delhi, Gujarat, Haryana, Karnataka, Madhya Pradesh, Rajasthan, and Uttar Pradesh adopted state-level legislations to reform their power sectors, with Delhi going as far as privatizing distribution under a performance-linked, benefits-sharing model.

What were the main lessons of phase 2 of the Indian power sector reforms? The privatization of utilities in Delhi rested in large measure on lessons learned from the Orissa experience: the most important design feature of Delhi's approach was use of a realistic trajectory for the reduction of aggregate technical and commercial losses as the bid variable, rather than an emphasis on the outright sale price as in the case of the Orissa divestiture. In addition, the government's continued engagement in the Delhi case, through provision of transitional support over five years to the private owners, helped the process by overcoming the cash flow crunch of early years before network improvements and loss reduction measures started yielding results.

Phase 3 (2003–12): Enactment of the Electricity Act and Subsequent Policy Initiatives to Introduce Competition and Create a Market in Generation, Transmission, and Distribution

In addition to the experience with divestiture in Orissa and privatization in Delhi, several states passed legislation to reform their power sectors in the wake of weak commercial and operational performance of their power utilities and the

fiscal burden imposed by their need for budget support. The Electricity Act of 2003, which followed, was the first comprehensive attempt to create an enabling environment for fundamental reforms in the sector.

The Electricity Act of 2003 was a key milestone in the history of India's power sector. The act addressed competition at various levels in a coordinated manner, thus providing the enabling framework to overcome barriers to private participation. The act resulted in significant improvements in the risk perception of the sector and once again whetted the investment appetite of investors who had hitherto been deeply skeptical of the structure and operations of the Indian power sector. The greatest effect was felt in the generation sector.

The following provisions of the legislation (and policies under it) represented the most substantial changes from the reform process as it was intended to function:

- The act did away with the need for techno-economic clearances (TECs) by the central government for thermal power projects and retained this requirement only for hydro projects above a given threshold of investments.
- The act provided for unbundling of the SEBs and for independence of the transmission function from all forms of trading. This independence created a new route for private capital to enter the power sector, that is, through investment in privately owned transmission lines that could be tendered by states.
- The act introduced open access at the transmission level from the first day and accorded choice of power suppliers to consumers above 1 MW, from no later than January 2009. Together with independence of transmission, the provisions for open access made a significant contribution to diminishing the purchasing power of erstwhile SEBs. Open access also created an alternative route to supply to third parties, including other state-owned utilities or third-party end consumers in case of default by a particular state-owned distribution utility under a PPA.
- The act made a decisive move toward competition in procurement of power and transmission services (and contracting with generators and transmission companies) through the provisions of Section 63 of the act. Guidelines were framed by MOP under the act and were adopted by states to procure power through tariff-based competitive bidding.
- In the critical distribution segment, the act provided a framework for the appointment of franchisees that is currently being pursued in a handful of states in both urban and rural areas. This, in many ways, provided a politically acceptable way forward on private participation in distribution, which had otherwise come to a standstill after the Delhi experience for lack of political willingness in other states.

The above policy and legislative provisions contributed significantly to changing private sector appetite toward investing in the sector. A conscious,

coordinated procurement of power on a very large scale, initiated by the central government, also allowed the industry to leapfrog to advanced technologies (for example, supercritical thermal generation technology for ultra mega power projects that were designed to supply 4,000 MW from a single plant) and offered much higher levels of efficiency and lower levels of emissions. Similar technological considerations are also integral now to interregional independent transmission projects, which include several 765-kilovolt-level projects on a regular basis.

The 11th Five-Year Plan (2007–12) coincided with a period of buoyant economic growth in India, a stock market bubble, record tax collections, and high levels of government support to the power sector. The plan also witnessed the highest rate ever of private participation in the power sector, as well as the highest achievement ever of total generation capacity addition (52,000 MW for the central sector, state sector, and private sector combined). Last but not least, the 11th Five-Year Plan also coincided with a rare global financial meltdown in late 2008, which sharply constrained (and still continues to constrain) investment in other parts of the world but seems to have had a less dampening effect on domestic private investment in the Indian power sector.

What then, has been learned from phase 3 of the Indian power sector reforms? Promulgation of the Electricity Act of 2003 unquestionably brought a new paradigm into the development of the power sector. The act helped outline bold and radical changes in the sector and its structure with the mandatory unbundling of SEBs, thereby helping the sector move away from negotiated MOUs (with guaranteed rates of return to the investor) for power procurement and introduce competition across the value chain, usher in open access in transmission and distribution, and take a differentiated approach to handling generation and supply in rural areas in the country. The 11th Five-Year Plan showcased the best performance to date of PSP in the power sector. Today, it represents a unique window for the study of private sector involvement. It is the first time that the effect of the reforms ushered in under the Electricity Act of 2003—and primarily the effect of competition among private bidders—can be studied. Without question, achievement of generation investment targets was substantially higher than in previous five-year plans.

Another lesson is that the only two cases of distribution privatization (Orissa and Delhi) in India preceded the Electricity Act of 2003. With the promulgation of the Electricity Act of 2003, the legitimacy of so-called distribution franchisees became well established, because the act provided for appointment of any person or entity to undertake distribution and supply on behalf of the distribution licensee within the licensee's area of supply. The central government hoped that this approach would confer the benefits of private ownership through a concession arrangement, but not transfer actual ownership, which was controversial and resisted by most state political authorities. However, as discussed in chapter 3, only a limited number of private sector distribution franchisees were established during the phase 3 reform period.

To sum up the momentous events of phase 3 and the lessons learned, one must recall that the introduction of reforms and competition under the

Electricity Act of 2003 brought forth a huge response in generation, a limited but respectable response in transmission (because not that many transmission lines were tendered in the first place), and a very limited response in distribution. Yet the distribution sector appears to be in the most urgent need of commercial focus and management practices that come with private participation. Many of the financial woes and shortfalls in operational performance that continue to haunt the distribution sector can be traced to the pre-reform period. Despite all the reforms, the political economy context for power sector distribution at the state level has, in fact, remained surprisingly unchanged over three decades.

Phase 4: Investor Uncertainty at the Start of the 12th Five-Year Plan

Despite the initial success of tendering more than 50,000 MW of new generation projects under the processes established in 2005 pursuant to the Electricity Act of 2003, the period since 2012 has highlighted significant structural and policy issues that, if unaddressed, are likely to sharply reduce future PSP in power generation. New capacity addition has already experienced a marked slowdown since 2011, with several aspects of the risk-sharing arrangements in the existing framework coming to the fore. The challenges ahead arise primarily from fuel risk (the spike in imported coal prices or the lack of supply for those generators who are relying on domestic coal) and liquidity risk (the negative net worth of the state utilities that are the primary customers for private generation investors). Governance concerns in the sector are an additional red flag.

In September 2012, the central government bailed out the state distribution companies through rescheduling of commercial debt to lighten their liquidity crunch.¹⁰ However, the fundamental economics of the sector remain unchanged and do not inspire confidence among investors. Many utilities suffer from a shortage of cash flow and cannot buy power for customers, so the utilities prefer to use rolling blackouts and cut off power instead. A private investor in power generation capacity therefore faces the increasingly real prospect that it will be unable to sell its power despite an environment of acute power shortages, because its primary customer, the distribution company, cannot afford to buy power. At the same time, third-party customers with a load of 1 MW or higher are entitled to buy directly from the generator through the open-access mechanism. However, there have been implementation delays on the part of state regulators in operationalizing this mechanism of the Electricity Act of 2003, and therefore the pool of customers for a private generation investor is still largely limited to the distribution companies.

What then has been learned so far from phase 4, which started in mid 2012? At present, the private investor community in generation is gripped by uncertainty over how to deal with shortages of domestic coal and highly volatile imported coal prices. A number of private investors who bid aggressively for contracts in the 11th Five-Year Plan are now locked in to 25-year PPAs with a near-bankrupt power procurer (that is, the distribution company). A looming, unanswered question preoccupying both lenders and investors is related to

whether the private sector can recover its required rate of return from selling services to bankrupt state distribution companies. State distribution companies, regardless of what they are paying for power to the generation companies, have not been able to commensurately increase their tariffs to the end users (although some have sharply increased tariffs very recently after a long interval), and there is a growing gap between average cost of production and average revenue realized for every unit of power. More to the point is the persistent problem of inefficient performance (high levels of losses and unaccounted for power) in state distribution companies that are still under substantial political control by state authorities and, therefore, far from operating on commercial principles. Thus, a dilemma exists: how to create the political will needed to implement far-reaching distribution reforms that will force utilities to deal with their performance problems; decrease technical losses to international standards (which are about one-sixth of present Indian averages); substantially reduce theft; collect all the revenues that the utilities are entitled to collect under the existing tariff regimes; and then (after demonstrating that in-house inefficiencies and distortions are being successfully addressed) make a case to the state regulator for any adjustments in tariff, if required. Until there is political will among state politicians, or until there is sustained public pressure to undertake drastic reform of the poorly performing distribution sector, the distribution situation is unlikely to change much.

Private Participation in Generation, Transmission, and Distribution

The following chapters examine the generation, transmission, and distribution segments of the power sector value chain in detail. Generation capacity is now procured and contracted by the state distribution utilities under the case 1 and case 2 methods, depending on whether the state distribution utility specifies the particular land and fuel to be used. For PSP in transmission, state transmission companies or the central power transmission company can use three modalities if they want to invite private investment: the MOP model, the Planning Commission model, and the joint venture route. For PSP in distribution, the option of outright privatization of utilities no longer appears to be on the table. Instead, a distribution franchise is the preferred approach to attracting private investment in a geographically ring-fenced part of a state utility's distribution network. All of these modalities of private participation throughout the power sector value chain will be presented and analyzed through the respective chapters on generation, transmission, and distribution.

Notes

1. Appendix A contains a summary description of the sector's institutional structure.
2. Legacy private distribution companies exist in Mumbai, Kolkata, Surat, and a few other cities. The companies were originally set up with private ownership at the turn 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 one of the private distribution companies and also has its own generation facility). Legacy private power companies are well managed but are few in number, and they predate the reforms that are discussed in this book by almost a century.

3. Under the Indian Constitution, electricity is a concurrent subject, meaning that both the central and state governments have jurisdiction over the sector. Administratively, therefore, central government organizations and the states have traditionally regulated different aspects of planning, sector policy, financing, and operations through a fairly noncontentious division of labor. Appendix A contains figure A.1, showing the institutional setup of the Indian power sector.
4. An exception occurred when central generators supplied electricity to one or more states, in which case the central government prescribed a tariff that was based on a negotiated power purchase agreement with the SEBs.
5. The reforms did not include any measures that would have diluted the state governments' control over the politically powerful distribution sector, where patronage coexisted with toleration of high levels of power theft, generous subsidies, and inefficient networks.
6. In such a case, therefore, foreign equity would fund 20 percent of project cost, foreign debt would cover 32 percent, and Indian debt would finance 48 percent of project costs. Foreign parties would have a total of 52 percent exposure against Indian lenders' exposure of 48 percent. To take a different example, where the equity investor was Indian and mobilized, for example, 30 percent of the project cost as equity, the debt requirement would be 70 percent. The Indian banks could meet at most 60 percent of the 70 percent debt requirement, that is, 42 percent of the total project cost. In this case, Indian parties would have 30 percent equity and 42 percent debt exposure, and the remaining debt of 28 percent would still have to come from foreign parties.
7. The three fast-track projects commissioned were (a) phase 1 (740 MW) of the 2,184-MW combined cycle gas-based Dabhol Power Project in Maharashtra (phase 2 was 90 percent complete when Enron exited India); (b) the 235-MW combined cycle gas-based Jegurupadu Power Project in Andhra Pradesh; and (c) the 250-MW Lignite-Based Power Project of ST-CMS in Tamil Nadu.
8. Appendix B contains the milestones and timeline of Dabhol project developments.
9. Appendix C contains a summary of the Orissa and Delhi privatization experiences. More detailed accounts of the Orissa and Delhi cases will be found in a forthcoming companion volume to this report that will contain case studies.
10. This was the second such taxpayer-funded central-sector rescue of the power sector in about a decade. The first bailout in March 2001 had been accompanied by unfulfilled promises from chief ministers to introduce metering, demand-side management measures, loss reduction investments, and increased basic rates for agricultural consumption in the form of a common minimum action plan.

Reference

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Private Sector Participation in Thermal Generation

Key Messages

- Growth in India's available power generation capacity has not kept pace with Indian demand.
- India continues to face severe energy shortages that will constrain economic growth rates; power supply is unreliable for those with access to the grid, and universal access objectives are far from being met (over 300 million Indians had no access in 2012).
- Various approaches to attract private investment in power generation have been tried since 1991; tariff-based competitive bidding introduced through the Electricity Act of 2003 has yielded the highest response and occurs through two approaches that contain different risk allocations to the private sector (cases 1 and 2).
- Ultra mega power plants introduced the relative allocation of risk and responsibilities based on perceived comparative advantages of the public and private sectors.
- Today, private sector investment in power generation accounts for about 27 percent of overall power generation capacity in India.
- Coal India Limited (a state-owned monopoly) has been unable to supply adequate coal for power generation since 2012, and this inability has dampened prospects for future private investment in thermal generation.
- Substitution of domestic coal with higher-priced imported coal raises power generation costs that cannot be passed on to customers (power utilities) because of the latter's weak financial situation and inability to charge higher retail tariffs to their customers who are the end users of electricity. Imported coal is also not always suitable to boilers and other power generation equipment that has been manufactured for use of domestic coal, which has different calorific and ash content relative to imported coal.

- Future allocation of limited low-cost domestic coal availability is a key short-to medium-term policy choice: should it be allocated to new plants owned by private generation investors or to fully-depreciated government-owned plants?
- Current projections indicate a drop in imported coal from fiscal year (FY) 2018 onward. If the projections turn out to be correct, then domestic coal non-availability may be an interim problem because coal production is supposed to increase with additional mines being contracted out and three main railway trunk routes under construction. Interim policies are therefore more likely to be focused on managing the blending of imported coal with domestic coal in the interim under a price-pooling mechanism, until annual contracted quantity picks up gradually for the power plants.

Importance of Power Generation

The National Electricity Policy document of the government of India recognizes electricity as one of the key drivers for rapid economic growth and poverty alleviation and had aimed to achieve the target of electricity to all and per capita availability of power of 1,000 units (that is, kilowatt-hours [kWh]) by 2012. This target, however, has not been met. Several challenges need to be addressed before India can achieve this objective. One of the most important concerns is that despite the reform process and private sector participation, the rate of resource augmentation and growth in energy supply has been less than the rate of increasing demand; therefore, India continues to face severe energy shortages. The average per capita consumption of electricity of 704 kWh in India is a fraction of the global average of 3,240 kWh. Irrespective of the expected growth in demand for electricity in the coming years, significant capacity additions need to be made even to bridge the current demand-supply gap. The peak demand is expected to be 218,209 megawatts (MW) in 2016/17 compared to 97,269 MW in FY2005/06.

Placing the Indian Power Sector in an International Context

After the United States, China, Japan, and the Russian Federation, India has the fifth-largest installed electricity generation capacity in the world. However, per capita availability of power in India is a negligible fraction compared to all the countries listed in table 2.1.

Power generation, which ensures supply of power and therefore validates other objectives such as energy access, is the first link in the value chain. For two decades, the government has been trying to attract a growing share of private capital for investment in power generation, in the hope of alleviating shortages. Continued robust economic growth in India will depend on, among other things, an adequate and reliable supply of electricity to the economy. The 12th Five-Year Plan (2012–17) envisages the addition of 100,000 MW of capacity by the private sector, which would represent a doubling of the capacity addition that was achieved in the 11th Five-Year Plan (2007–12).

Growth of Private Sector Participation in Power Generation in India

Figure 2.1 depicts the growth of private sector investment in power generation since 1991. Private sector installed capacity in 1992 was 2.85 gigawatts (GW) and grew to 46.11 GW in 2012, at a 15 percent compound annual growth rate (CAGR).

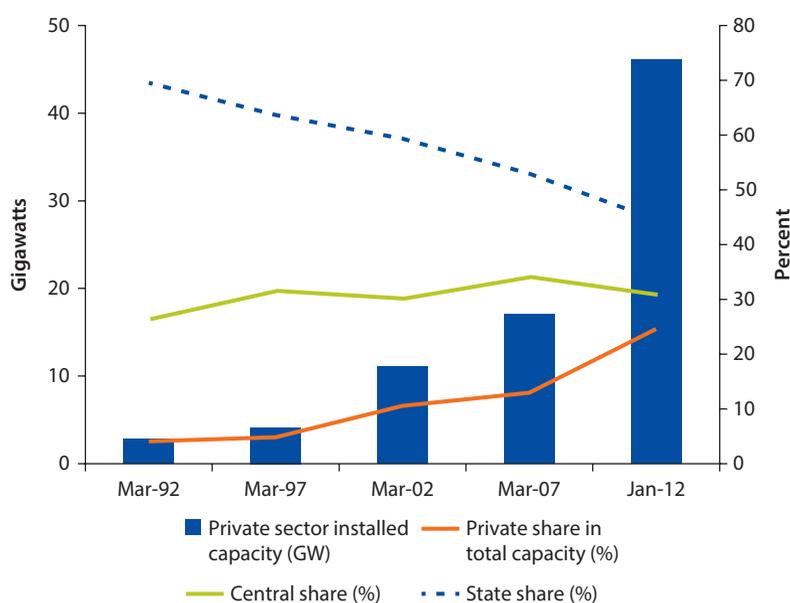
The overall share of private installed generating capacity was only 4 percent during FY1991/92 and substantially increased to 25 percent in the span of

Table 2.1 Installed Electricity Generation Capacity of the Most Populous Countries

Country	Population	Installed power generation capacity (gigawatts)	Primary fuel
China	1,347,000,000	1,140	Coal
India	1,241,000,000	212	Coal
United States	312,000,000	1,190	Coal
Brazil	197,000,000	115	Hydro
Russian Federation	143,000,000	230	Gas
Japan	128,000,000	245	Nuclear + hydro + coal
Mexico	115,000,000	59	Gas, fuel oil, and diesel
Turkey	74,000,000	55	Gas + hydro
United Kingdom	62,700,000	94	Gas

Source: Based on U.S. Energy Information Agency and International Energy Agency data.

Figure 2.1 Growth of Private Sector in Power Generation Segment



Source: World Bank 2012.

Note: GW = gigawatts.

20 years. The major growth occurred in 1997–2002 and again in 2007–12, with almost 22 percent CAGR.

Figure 2.1 also indicates how the state governments' share in total generating capacity declined over the period, while the share of the private sector grew significantly and that of the central government increased only marginally.

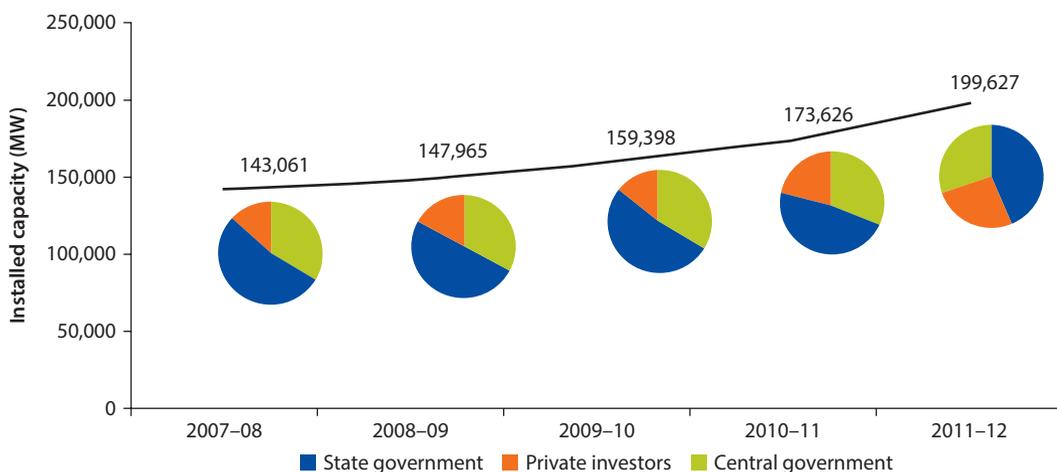
The generation segment of the power sector has attracted the most interest from private sector players, largely dominated by Indian companies. A few international firms such as China Light and Power (CLP) and AES figure in the market, but their generation capacity in India is limited. Over the years, India has built a private developer base not only from companies in the power and infrastructure sectors, but also from companies in other sectors that have come forward to submit bids for investment in the power sector. Table 2.2 and figure 2.2 illustrate again the growth in private investment and shrinkage of state and central sector investment in the growing installed capacity of power generation assets, specifically during the 11th Five-Year Plan (2007–12).

Table 2.2 Installed Capacity of Indian Power Generation Assets

Fiscal year	Megawatts				Share (%)			
	Central sector	State sector	Private sector	Total installed capacity	Central sector	State sector	Private sector	Total installed capacity
2006/07	45,121	70,096	17,113	132,329	34	53	13	100
2007/08	48,361	74,689	20,011	143,061	34	52	14	100
2008/09	48,971	76,116	22,879	147,965	33	51	15	100
2009/10	50,993	79,392	29,014	159,398	32	50	18	100
2010/11	54,413	82,453	36,761	173,626	31	47	21	100
2011/12	59,683	85,919	54,276	199,627	30	43	27	100

Source: World Bank 2012.

Figure 2.2 Evolution of Ownership of Power Generation Assets, 2007–12



Source: Central Electricity Authority.

Note: MW = megawatt.

Independent Power Projects Policy of the Early 1990s

Private participation in generation started with the Electricity Laws (Amendment) Act of 1991 amid a serious financial crisis at central and state levels, when public coffers had limited or no surplus to invest in power generation projects. The amendment allowed private parties (including foreign investors) to establish, operate, and maintain electricity generation plants as independent power producers (IPPs) with up to 100 percent ownership and to enter into long-term power purchase agreements (PPAs) with state electricity boards (SEBs). The amendment was supported by the independent power projects policy implemented in 1992 that established new financial arrangements for private producers. Key features of the policy were as follows:

- Sale of power at a structured two-part tariff covering fixed costs and variable costs (capacity charge and energy charge).
- Assured 16 percent return on equity in the currency of investment, at 68.5 percent plant-load factor for thermal power projects and 90 percent availability for hydropower plants.
- Foreign currency risk allowed as a pass-through in tariffs, to be borne by the SEBs.
- Incentive scheme based on capacity utilization of power plants.
- Provision of counter-guarantee by the central government on a case-by-case basis to the private power companies, backing the payment obligations of SEBs upon specific request by the concerned state government.

The above incentives were initially applauded by the private sector; by 1995, around 189 offers worth US\$100 billion in investment and potential capacity addition of 75 GW had been put forward. However, only a handful of projects ultimately moved to a stage of financial closure. Many administrative hurdles emerged in gaining required clearances from states and the central government authorities—besides challenges in obtaining the Central Electricity Authority's (CEA) techno-economic clearance (TEC) and negotiating the various project agreements such as the PPA, fuel supply agreement, and fuel transportation agreement—which quickly dampened the mood of several investors.

For accelerated implementation, the government declared eight of the most promising projects to be fast-track projects with expedited statutory clearances and provided a four-tiered payment security against nonpayment of dues by SEBs, including letter of credit, escrow accounts, state government guarantees, and counter-guarantees by the central government (table 2.3).

Despite the substantial policy changes and intent demonstrated by the central government, only three of the eight fast-track projects were commissioned.¹ Among these three projects was the first phase of the Dabhol Power Project,² which was planned despite the questionable economics of a liquefied natural gas-fired base-load power plant in Maharashtra. By the mid-1990s, Enron's Dabhol Power Project had run into several issues with the state government,

Table 2.3 Eight Most Promising Fast-Track Projects

<i>Project</i>	<i>Capacity (megawatts)</i>	<i>State (developers)</i>
Dabhol Power Project (LNG)	2,184 (740 + 1,440)	Maharashtra (Enron, Bechtel, General Electric)
Jegurupadu (CCGT)	235	Andhra Pradesh (GVK Reddy)
Neyveli Thermal Power Station	250	Tamil Nadu (ST-CMS Electric Company Private Ltd.)
Bhadravati (coal)	1,072	Maharashtra (Central India Power Company Ltd. by Nippon Denro Ispat Ltd.)
Godavari (CCGT)	208	Andhra Pradesh (Spectrum Power)
Visakapatnam	1,040	Andhra Pradesh (Hinduja National Power)
Mangalore Power Project	1,000	Karnataka (Cogentrix, China Light and Power)
Ib Valley	420	Orissa (AES Transpower)

Source: World Bank 2012.

Note: CCGT = combined cycle gas turbine; LNG = liquefied natural gas.

including high power tariffs being owed by the state immediately after the signing of the PPA with the SEB in 1993 and opposition parties in Maharashtra alleging irregularities. After the ruling party was voted out of power in the state general elections in 1995, the terms of the PPA were renegotiated with Enron in an environment of mutual mistrust and recriminations. When phase 1 of the plant was commissioned and the plant started supplying power in 1999, the SEB and Dabhol traded several charges against each other over the exorbitant cost of power, and ultimately, the Maharashtra State Electricity Board stopped payments to Dabhol in 2001 and sought to cancel its PPA. The complete Dabhol case study is provided in a companion volume to this book (volume 2, Case Studies).

Key Issues in Implementation of the IPP Policy

The following were significant issues in the implementation of the IPP policy of the 1990s:

- The SEBs were in poor financial health and were not perceived as reliable counterparts to IPP contracts, either by prospective developers or by their financiers. Guarantees by the state governments and counter-guarantees by the central government were available only to the fast-track projects and not commonly to other projects.
- The cost-plus negotiated method³ of project development, with tariffs determined on the basis of capital costs, meant that private parties had no real incentives to be efficient. It was not surprising, therefore, that a majority of developers proposed investments that translated into tariffs well above the benchmarks existing in the public sector. Moreover, the pass-through in tariffs of foreign currency risks added to the risk perception on the part of state governments.
- Except for the fast-track projects, obtaining statutory clearances on power projects was arduous and time consuming in the 1990s. Procedures for environmental clearances in particular have subsequently undergone a fair degree

of standardization,⁴ and today they are reasonably time-bound for thermal projects in particular. All thermal projects in the 1990s also required a TEC, which was an added due diligence in the absence of competitive measures to determine capital costs or tariffs. The requirement of a TEC was abolished later upon enactment of the Electricity Act of 2003.

- Delays in finalization of contracts (power purchase, fuel supply, fuel transportation, and so forth) were routine. SEBs were left to negotiate contracts on their own with little or no prior knowledge of international contracts (for example, “take or pay” clauses) and their implications. Lack of standardization in approach meant that each project was treated differently, and it was not uncommon for fully negotiated contracts to be reopened after a change in management within the SEB or in political leadership in the state government. The lack of transparency in this approach also allowed for allegations of corruption and malfeasance to be leveled more easily, making civil servants wary of finalizing contracts involving such large investments during their tenures.
- The cost of power from private projects was much higher than that from public sector generation projects. Several factors led to a higher capital cost: (a) the absence of competition and therefore a lack of any real effort by the private sector to optimize costs; (b) the use of imported equipment, resulting in increased foreign exchange exposure; and (c) the overall higher risk perception of such projects, resulting in higher cost of capital. All these factors contributed significantly to making IPP power very expensive relative to what had prevailed before, when most power was purchased by SEBs from public generation companies.

Despite the initial euphoric interest among Indian and foreign investors, the actual implementation of projects (because of the factors outlined above) was dismal. It also became clear over time that SEBs, being weaker financially, had little bargaining power in the process. The procurement process was inefficient and costly because of a lack of competition and transparency.

Intermediate Policy Initiatives for Private Sector Participation in Generation

Following the initial experience of the private power policy of 1991, the central government made several additional isolated attempts to attract the private sector into generation projects. Some of the significant efforts were as follows:

- To meet the demand-supply gap faster, the government promoted liquid fuel-based generation (because of its relatively shorter gestation period) through the Liquid Fuel Policy (1995). This resulted in some existing gas-based power plants stepping up their plant utilization through the use of naphtha, but no new capacity was planned for liquid fuel, because of its high cost of generation (from high fuel charges).

- State governments were postponing critical renovation and modernization requirements. This, in turn, resulted in decreased efficiency in state-owned coal-fired generation plants in particular. The central government created policy guidelines for private sector participation in renovation and modernization of existing plants, but not a single project to date has actually been implemented through private participation in renovation and modernization.
- In 1998, the central government issued the Hydropower Development Policy, intended to exploit the huge hydroelectric potential in the northern and northeastern regions of India. A few medium-size and large hydro projects have been developed since then.
- With the growth in generation, the central government also felt the requirement for substantial additional investment in transmission lines. The Electricity Laws (Amendment) Act of 1998 was passed to recognize transmission as a distinct activity, thereby enabling private investment in the transmission sector through issuance of transmission licenses at interstate and intrastate levels.
- The Ministry of Power issued a Mega Power Policy in 1995 to allow investors to benefit from economies of scale by setting up large-scale power projects directly at coal mines (pit-head) and supplying coal to load centers through appropriately planned, dedicated transmission infrastructure. The policy sought to award projects through competitive bidding, and the central agencies—namely, the CEA, National Thermal Power Corporation (NTPC), and Power Grid Corporation of India Ltd. (POWERGRID)—were to provide catalytic support through project identification, feasibility, and transmission access arrangements. The policy later factored in certain fiscal concessions to pass on the benefits of scale to consumers. The fiscal benefits were in the nature of waiver of customs duty and “deemed exports” benefits.

Most of the above attempts met with limited success. The Electricity Act of 2003 replaced the legal framework for the sector that had hitherto been governed by the Indian Electricity Act of 1910, the Electric Supply Act of 1948, and the Electricity Laws (Amendment) Act of 1998. Promotion of competition in the electricity industry in India has been one of the key objectives of the Electricity Act of 2003.

Post-Electricity Act of 2003: Tariff-Based Competitive Bidding

Three sections of the Electricity Act of 2003 provide for tariff regulation and determination across different segments of the industry. Sections 61 and 62 of the act provide for those aspects for generation, transmission, wheeling, and retail sale of electricity by the “Appropriate Commission.” Section 63 of the act states that “notwithstanding anything contained in Section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through

transparent process of bidding in accordance with the guidelines issued by the Central Government.”

The central government issued tariff-based competitive bidding guidelines in 2005 for procurement of power by distribution licensees (state utilities, also referred to as distribution companies). This issuance was done under Section 63 of the act to create competition in generation and to reduce overall power procurement cost by distribution companies. Distribution companies had previously purchased power under contracts on a case-by-case basis with IPPs, assuring the IPPs of a 16 percent return on equity. Thereafter, the competitive bidding guidelines were applicable for long-term procurement (seven years and above) and medium-term procurement (one to seven years) of base-load, peak-load, and seasonal power requirements.

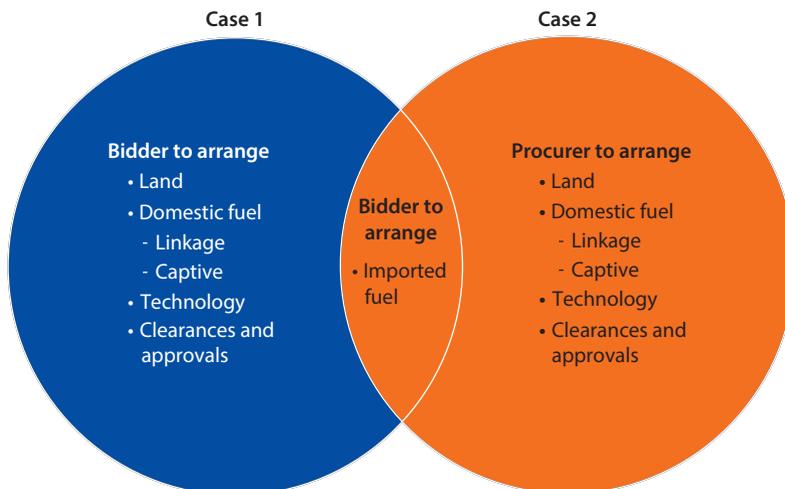
Two routes are available for competitive procurement of power by distribution licensees—case 1 and case 2. These routes are compared in table 2.4 and figure 2.3 (note that the procurer is the distribution company).

Table 2.4 Competitive Procurement Characteristics by Case

<i>Case 1</i>	<i>Case 2</i>
<ul style="list-style-type: none"> • Procurer is not to specify the location, technology or fuel and is interested only in the power to be procured. • Bidder takes on the responsibility for all clearances, approvals, and so forth. • Case is relevant for states with limited feasible sites for power generation projects. 	<ul style="list-style-type: none"> • Procurer must specify the location, technology, and fuel and shall make the land available for project development along with clearances and approvals. • Procurer shall make the fuel available for the project in all cases except for imported fuel situations. • Case is relevant for states that can identify feasible sites for power generation and provision.

Note: Procurers may, subject to approval of the appropriate commission, use terms different from the competitive bidding guidelines; for example, for the Lakhisarai and Pirpainti thermal power projects in Bihar (case 2), the bidders were able to arrange for fuel for the entire term of the power purchase agreement, a deviation approved by the Bihar Electricity Regulatory Commission.

Figure 2.3 Competitive Procurement



Bid Process

For long-term procurements under case 2, a two-stage bid process with a separate request for qualification (RFQ) and request for proposal (RFP) stage is to be adopted. The procurer (distribution company) may adopt a single-stage bid process for long-term or medium-term procurement under case 1, combining the RFP and RFQ processes.

Tariff Structure

The guidelines specify a two-part tariff structure comprising separate capacity and energy components. The energy charge and capacity charge can, in turn, be quoted on the basis of escalable and nonescalable components. Table 2.5 summarizes the possible tariff structures for case 1 and case 2 projects.

Selection of bidders is on the basis of lowest levelized tariff. Nonescalable components are to be quoted year-on-year for each contract year from the commercial operation date, over the term of the PPA. Escalable components are to be quoted only for the first year and are then automatically escalated by using the relevant Central Electricity Regulatory Commission (CERC) index over the term of the PPA. The evaluated tariff for any contract year is then computed as the summation of all escalable and nonescalable components for the contract year. The quoted tariff stream over the term of the PPA is then levelized by using the CERC specified discount rate to arrive at the quoted levelized tariff for each bidder.

Payment of the escalable components over the term of the PPA is based on payment indexes revised semiannually by CERC. Nonescalable components are paid as quoted for the contract year without any adjustments.

Table 2.5 Possible Tariff Structures for Case 1 and Case 2 Projects

<i>Tariff</i>	<i>Case 1</i>	<i>Case 2</i>
Capacity charge	<ul style="list-style-type: none"> • Bidder can quote escalable capacity charges and nonescalable capacity charges. 	<ul style="list-style-type: none"> • Bidder may quote firm capacity charges for the PPA term with "Nil" escalable quoted charges.
Energy charge	<ul style="list-style-type: none"> • Bidder can quote escalable energy charges and nonescalable energy charges. The escalable or nonescalable components may include the following elements, depending on the type of fuel: <ul style="list-style-type: none"> – Inland transportation charge – Overseas transportation charge – Fuel handling charge 	<ul style="list-style-type: none"> • Bidder may quote firm quoted energy charges for the PPA term with "Nil" escalable quoted charges.
Transmission charges and losses	<ul style="list-style-type: none"> • Applicable only when quoted tariffs must be adjusted for transmission charges and losses to arrive at the cost of procurement at the state interface 	<ul style="list-style-type: none"> • Not applicable

Note: PPA = power purchase agreement.

Response of the Private Sector to Case 1 and Case 2 Procurement through Competitive Bidding

Since the introduction of tariff-based bidding guidelines, procurement of 19,527 MW of power has been concluded through the case 1 approach. Gujarat and Maharashtra are the leading states, having procured 5,810 MW and 5,154 MW of power, respectively, during 2007–10. The highest level of total case 1 procurement occurred in 2010, with 8,410 MW, followed by 7,613 MW of power procured through case 1 in 2007. Table 2.6 presents a summary of all case 1 bids, showing amounts and prices in Indian rupees per kilowatt-hour.

As of 2012, there were seven state-level bids for procurement of power through the case 2 approach, aggregating to 10,440 MW of power procured. (This excludes the four ultra mega power plants [UMPPs] for which contracts have been awarded, totalling 15,880 MW; see following paragraph for more information on this program.) The major procuring states under case 2 are Uttar Pradesh (three projects totalling 4,500 MW) and Punjab (two projects totalling 3,300 MW). Among all state-level case 2 bids, the lowest tariff recorded was Rs 0.81/kWh for the 1,320-MW Bhaiyathan Thermal Power Project in Chhattisgarh that was awarded to Indiabulls Power Limited. The maximum selected tariff was Rs 3.02/kWh for the 1,980-MW Phase 1 of the Prayagraj–Bara Thermal Power Project awarded to Jaiprakash Power Ventures Ltd. (JPVL) in Uttar Pradesh. Table 2.7 provides the summary of all the case 2 bids (note that apart from Jhajjar and Anpara C, none of the other projects have, as yet, been commissioned).

Table 2.6 Summary of Case 1 Bids

Year	Procurer	Quantity of power (megawatts)	Winning bid prices (Rs/kilowatt-hour)	
			Minimum	Maximum
2007	Gujarat Urja Vikas Nigam Ltd. (GUVNL)	3,200	2.2498	2.8900
2007	Haryana Power Generation Corporation Ltd.	2,113	2.3600	2.9400
2007	Madhya Pradesh Power Trading Company	2,300	2.3400	2.9500
2008	Maharashtra State Electricity Distribution Company Ltd.	2,304	2.6424	2.7286
2009	Rajasthan Rajya Vidyut Prasaran Nigam Ltd.	1,200	3.2483	3.2483
2010	Gujarat Urja Vikas Nigam Ltd. (GUVNL)	2,610	2.3450	2.8000
2010	Bihar State Electricity Board	450	2.6400	2.6400
2010	Power Company of Karnataka Ltd.	2,180	3.7570	3.8890
2010	Maharashtra State Electricity Distribution Company Ltd.	2,850	2.8790	3.2800
2010	Reliance Infrastructure Limited	320	3.4210	3.4210

Source: World Bank 2012.

Table 2.7 Summary of Case 2 Bids, Other than UMPPs

<i>Project</i>	<i>Quantity of power (megawatts)</i>	<i>Developer</i>	<i>Winning bid prices (Rs/kilowatt-hour)</i>	<i>Project status</i>
Bhaiyathan Thermal Power Project	1,320	Indiabulls Power Limited	0.81	Forest clearance for captive coal mine rejected by Forest Advisory Committee; project construction doubtful
Anpara C Thermal Power Project	1,200	Lanco Kondapalli Power Ltd.	1.56	Commissioned in November 2011
Sangam–Karchana Thermal Power Project	1,320	Jaiprakash Power Ventures Ltd.	2.97	Promoter reportedly expressed unwillingness to construct this project
Prayagraj–Bara Thermal Power Project	1,980	Jaiprakash Power Ventures Ltd.	3.02	Expected COD by July 2014
Jhajjar Power Station	1,320	China Light and Power India Private Ltd.	2.99	Commissioned in 2012 but ongoing problems at plant with supply of domestic coal
Talwandi Sabo Thermal Power Project	1,980	Sterlite Energy Ltd.	2.86	Expected COD by January 2014
Rajpura Thermal Power Project	1,320	L&T Power Development Ltd.	2.89	Expected COD by May 2014

Source: World Bank 2012.

Note: COD = commercial operation date; UMPP = ultra mega power plant.

Ultra Mega Power Plant Projects

UMPP projects have a capacity of about 4,000 MW each, use advanced high-efficiency technology, and aim to derive economies of scale in generation as well as transmission of power. These projects are developed with supercritical technology to achieve high fuel efficiency, resulting in fuel savings and lower greenhouse gas emissions. The projects have been conceived either as pit-head projects (using dedicated captive coal blocks) or as coastal projects using imported coal to be arranged by the bidders themselves.

UMPPs adopted a novel approach to the preconstruction tasks that recognized the relative comparative advantage of the public sector over the private sector in certain areas. The Power Finance Corporation (PFC) is the focal point (nodal agency) entrusted with the responsibility of coordinating and conducting the competitive bid process for selection of a developer for each project through tariff-based competitive bidding. PFC sets up a special purpose vehicle (SPV) as a 100 percent-owned subsidiary for each identified UMPP. It completes all the groundwork, including acquisition of land, acquisition of environmental clearance and water allocation, and allocation of the captive mine (in the case of a captive coal mine-based UMPP) in the name of the SPV, before bidding out the project. Once a successful bidder is identified, the bidder buys 100 percent equity in the SPV. The UMPP modality is designed to allocate responsibilities based on comparative advantage; that is, as a public sector nodal agency, PFC should be more easily and more efficiently able to undertake steps involving government clearances and interface, and this leaves the tasks of designing,

financing, constructing, and operating the plant to the private sector. In this manner, the private party can proceed immediately with the activities that correspond to its core competence and does not spend 18–24 months up front trying to put in place the preconstruction arrangements.

Response of the Private Sector

Twelve proposed UMPPs have been identified, of which four have already been awarded to developers on the basis of the two-stage competitive bidding process (RFQ + RFP) outlined earlier. Table 2.8 provides the status of identified UMPP projects. Most of the awarded projects are still in the construction stage, and the first unit of Mundra UMPP has been commissioned recently. The private sector's

Table 2.8 Status of Identified UMPP Projects

<i>Project</i>	<i>Developer</i>	<i>Fuel source</i>	<i>Selected bid (Rs per unit)</i>	<i>Status of project commissioning (COD)</i>
Coastal Gujarat Power Limited, Mundra UMPP, Gujarat (5 × 800 MW)	Tata Power	Imported coal (arranged by developer)	2.26	First unit COD: February 2012 Project COD:- February 2013
Sasan Power Limited, Sasan UMPP, Madhya Pradesh (6 × 660 MW)	Reliance Power	Allocated domestic coal mine	1.196	First unit COD: March 2013 June 2014
Coastal Andhra Power Ltd., Krishnapatnam UMPP, Andhra Pradesh (6 × 660 MW)	Reliance Power	Imported coal (arranged by developer)	2.336	February 2015 ^a under the signed PPA
Jharkhand Integrated Power Ltd., Tilaiya UMPP, Jharkhand (6 × 660 MW)	Reliance Power	Allocated domestic coal mine	1.77	June 2017
Orissa Integrated Power Ltd., Orissa UMPP, Sundargarh District		Allocated domestic coal mine		Bid process restarted in 2014 under revised standard bidding documents
Chhattisgarh Surguja Power Ltd., Chhattisgarh UMPP, Surguja District in Chhattisgarh		Allocated domestic coal mine		Bid process restarted in 2014 under revised standard bidding documents
Coastal Tamil Nadu Power Ltd., Cheyyur UMPP, Tamil Nadu				Bidding yet to commence
Coastal Maharashtra Power Ltd., Maharashtra UMPP				Bidding yet to commence
Coastal Karnataka Power Ltd., Karnataka UMPP				Bidding yet to commence
Tatiya Andhra Mega Power Ltd., Andhra Pradesh 2nd UMPP				Bidding yet to commence
Sakhigopal Integrated Power Co. Ltd., Orissa Additional UMPP 1				Bidding yet to commence
Ghogarpalli Integrated Power Co. Ltd., Orissa Additional UMPP 2				Bidding yet to commence

Source: Power Finance Corporation.

Note: COD = commercial operation date; MW = megawatt; PFC = Power Finance Corporation; RFQ = request for qualification; UMPP = ultra mega power plant.

a. Since June 2011, the developer has halted construction work at the project site, citing new regulations by the government of Indonesia that imposed a tax on the sale of coal, based on a benchmark price, irrespective of actual sale value. The procurers have served a termination notice on the developer, and the matter is in court.

response to UMPP projects was enthusiastic, in terms of both participation and overall reduction of tariffs. Reliance Power won three of the first four UMPP projects with Sasan UMPP, resulting in the lowest bid (Rs 1.196/kWh), whereas the highest bid is for the imported coal-fueled Mundra UMPP (Rs 2.260/kWh).

Comparison of Case 1 and Case 2 Bids with Noncompetitively Awarded (by Memorandum of Understanding) Projects

Under the National Tariff Policy of 2005, a five-year exemption was provided for public sector projects to contract with distribution utilities without going through a competitively bid process pursuant to Section 63 of the Electricity Act of 2003. In effect, the tariff of public sector projects continued to be negotiated and determined by appropriate commissions under Section 62 of the act on a cost-plus basis. In September 2010, when this five-year exemption came up for review, the CERC issued statutory advice to the central government not to defer the deadline. In effect, this advice initiated a transition of the public sector to also take part in competitive tariff-based bidding beginning January 6, 2011.

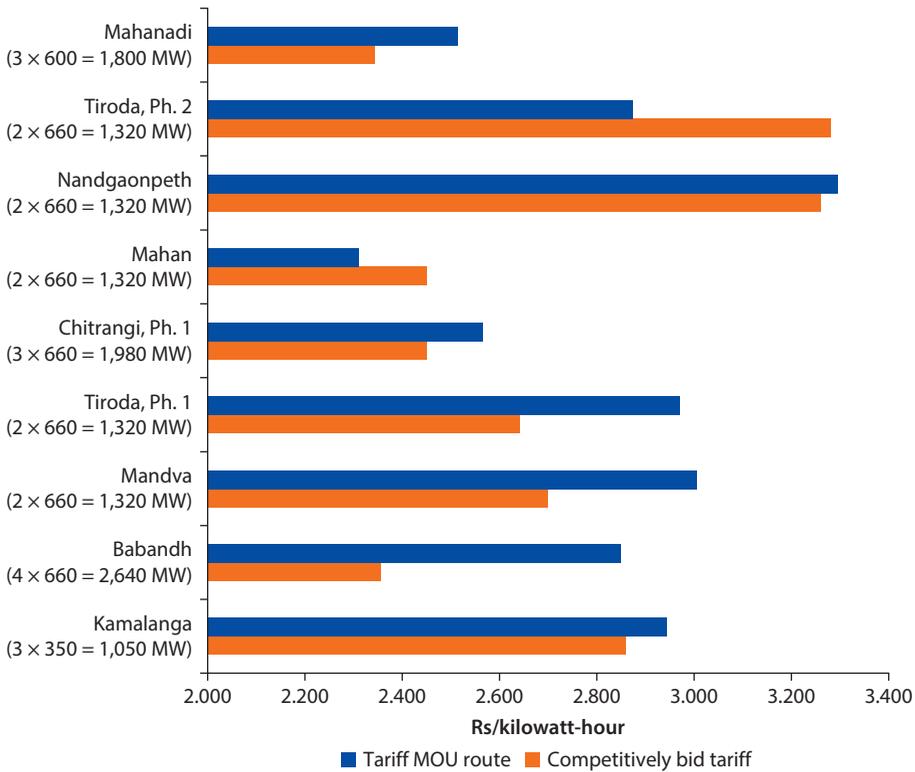
Before making its recommendation, the CERC carried out a detailed exercise⁵ of comparing tariffs realized on competitively bid projects, with an assumed construction of an equivalent plant contracted as a memorandum of understanding (MOU) plant (with tariffs determined through the negotiated route by the appropriate commission). The hypothetical MOU plant was assumed to be no more efficient than the most efficient NTPC plant, in effect yielding a public sector comparator for the project; that is, the CERC compared the bidding pattern for each project with an equivalent tariff, assuming that the plant was built with the same degree of efficiency as an NTPC plant. The hypothetical comparator is referred to as the *MOU route* as opposed to the *competitive bidding route*. The CERC accepted 14 projects, which had recently participated in case 1 and case 2 tenders. Figure 2.4 shows that, in the majority of cases, the competitively bid case 1 tariff was substantially lower than the expected tariff that would have resulted from the MOU route. For case 2 bids, as shown in figure 2.5, all of the results are significantly lower than under the MOU route.

On the basis of this comparison with public sector projects, which were still using the MOU route under their five-year exemptions, the CERC reiterated its advice to the central government to transition all public sector projects to a competitive basis of procurement under case 1 or case 2. This approach would effectively remove any regulatory determination of tariffs for projects for which developers signed PPAs after January 5, 2011.

In general, certain other factors can be concluded for case 1 and case 2 projects as follows:

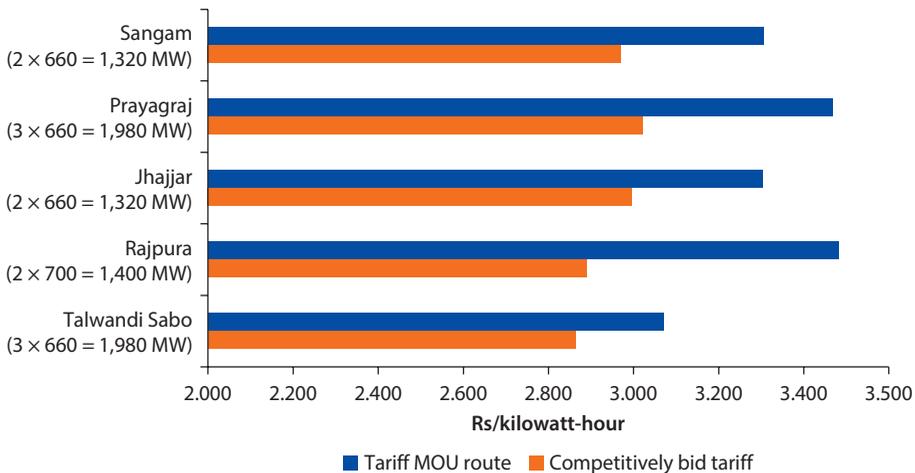
- Comparable case 1 project quotes appear to be significantly more expensive than case 2 project quotes (Tiroda phases 1 and 2 are differently priced, for the very same project, under case 2 and case 1, respectively). This outcome is not

Figure 2.4 Case 1 Bids



Source: Central Electricity Regulatory Commission.
 Note: MOU = memorandum of understanding; MW = megawatt.

Figure 2.5 Case 2 Bids



Source: Central Electricity Regulatory Commission.
 Note: MOU = memorandum of understanding; MW = megawatt.

surprising, because case 1 projects leave all risks of obtaining consents and clearances, including exposure to fuel-related uncertainties, to the bidder. This higher risk is reflected in a higher price quoted by the bidders.

- In most cases of coal-linked projects (that is, case 2 projects), when the procurer has the obligation to supply domestic coal, the linkage provided by Coal India Limited (CIL) or its subsidiaries is only for 70 percent of the requirements of the plant. It is assumed that the balance has been sourced by the developer through the CIL e-auction process⁶ or through imports. Shortfalls are therefore extremely costly, and they are being increasingly factored into case 2 bids in a gradual manner (that is, case 2 prices are starting to rise). Even more disturbing are the instances in which CIL is failing to meet its commitment to supply the basic 70 percent of the fuel required by coal-linked case 2 projects, such as the recently commissioned 1,320-MW Jhajjar Power Station.

Prospects for Future Private Participation in Power Generation: What Is Holding Back Private Investors?

Although the initial private sector response to case 1 and case 2 projects was overwhelming, it has now dropped sharply on account of the uncertainties in the sector. Prospects for continued private sector investment in generation will depend largely on how and when the following three primary concerns of private generation investors are resolved:

- *Fuel Risks—Domestic and Imported Coal–Related Uncertainties for Private Power Developers.*⁷ As explained above, in the case 1 power procurement model, the private developer is expected to arrange the fuel requirements for its project and assumes the entire risk on this account. Case 1 technical qualifications require the bidder to have linkages (supply contracts) for the entire capacity for which it is bidding. However, CIL has resorted to providing coal linkages for substantially lower capacity utilizations for projects, even where it has signed on to firm fuel supply agreements. This is both a risk and a concern for developers, who are not sure of the amount of coal that would actually be made available by CIL, even though they have uncovered commitments under the case 1 PPA to ensure plant-load factors and availability of the order of 80 percent. Bidders must then procure the shortfall of coal through e-auction or blend with imported coal, but both may lead to substantially higher tariffs (over the life of the contract) after a PPA is entered into on the basis of a competitively bid tariff. Bidders who have chosen to rely on imported coal (to avoid interacting with CIL) are also facing massive difficulties. These difficulties are due to unexpected regulatory changes in Indonesia and Australia that have unravelled the bidders' hedging strategies and sharply raised the cost of imported coal, while the bidders also remain locked into 25-year PPAs.

- *Liquidity Crisis in the Sector:* This topic will be analyzed in detail in chapter 4 on distribution sector issues.
- *Governance Issues:* The power sector has transitioned from outright state ownership of vertically integrated SEBs in the 1990s to a more unbundled scenario for generation, transmission, and distribution, with a state regulatory commission in attendance. However, realities at the project level (and political interference at the state level) have not changed significantly from the SEB days. Governance remains a challenge. There is often a sense of excessive camaraderie and common purpose among state politicians, state regulators, and the heads of the state distribution utilities. Use of electricity as a tool of political patronage (mentioned earlier) remains widespread.

The Coal Crunch and Choices Facing Policy Makers

India's annual thermal coal demand is expected to climb to 730 million metric tons by 2017, compared to a demand of 650 million metric tons and production of about 440 million metric tons today. A study by Prayas Energy Group (2013) notes that 42 GW of planned capacity have been mothballed as of January 2012 because of coal supply bottlenecks and price curbs. Private investors had won rights to build plants by bidding prices at which they would sell electricity. Power companies that have put additional coal-fired capacity construction on hold had bid to sell electricity at an average of Rs 2.50 (US\$0.05) per kilowatt-hour, while current fuel prices put the cost of producing power at about Rs 3.00 per kilowatt-hour, thereby slowing the growth of coal-fired plants.

According to the New Coal Distribution Policy (amended July 26, 2013), all plants to be commissioned between January 4, 2009, and March 31, 2015, will have fuel supply agreements signed with annual contracted quantities of 65 percent, 65 percent, 67 percent, and 75 percent, respectively, over the remaining years of the 12th Five-Year Plan. The option of preference in coal distribution is thus addressed only through curtailing supply to these plants. Recent projections indicate that production and transportation bottlenecks should ease beyond 2017 to result in a nominal reduction in coal imports (see box 2.1).

Imported coal price is still about 25–35 percent higher than Indian domestic coal prices based on heat content. Thus, one could assume that a combined or pooled price would be higher than current domestic coal prices paid by thermal power plants.

Logistical Difficulties with Physical Pooling of Imported and Domestic Coal

In July 2012, CIL reported that it planned to import up to 30 million metric tons of coal in 2012 to meet rising domestic demand and mitigate power shortages. However, imports are only a first step. Coal imports and delivery of the imports to intended destinations require considerable logistical capability and planning. Coordinated transport arrangements at ports and railways, as well as suitable

Box 2.1 What If the Coal Availability Projections Are Too Optimistic and There Is Still a Coal Shortage in 2018?

Fast forward to a scenario in 2018 where coal shortages persist. Who should receive the scarce domestic coal? The following is one scenario, of two radically different, alternative approaches that are presented for discussion purposes:

- First priority could be given to the old vintage central sector and state sector power generation plants that are fully depreciated (commissioned in 1993 and earlier).
- Next priority could be given to newer central and state sector plants (commissioned from 1994 to 2004).
- Next priority could be given to private sector plants that have sourced their equipment to be able to function on Indian coal only and would face hardship if they had to use other grades of coal, and thus they need access to Indian coal even if they cannot achieve 80 or 85 percent plant-load factor.

In an alternative scenario, which may be focused on reviving waning private sector interest in generation investments and rescuing half-built private plants that risk becoming stranded because of the coal shortage, the following could be a likely way forward:

- UMPPs may be first in line because they are highly visible and attract significant amounts of private sector capital per plant (about Rs 20,000 billion). Future UMPPs are expected to have a full pass-through of fuel price risk, but existing ones have asked for and received some relief (Tata Power as well as Sasan coal for Chitrangi by Reliance Power Ltd.).
 - Next in line would be large subcritical plants that were recently commissioned, particularly those linked to private transmission lines, so that two categories of private investors (generation and transmission) would be placated with the coal allocation policy, and overall investor confidence in the power sector would increase.
 - Central and state sector plants would come last in this scenario, which would be focused on wooing the private sector with the coal allocation policy.
-

loading and unloading facilities, may not be in place, meaning that imported coal movements may be constrained by on-ground realities and limitations and that true pooling may not be physically possible.

Domestic coal raises similar logistical challenges because of the uneven geographical allocation of India's coal resources:

- Most of the reserves are found in the eastern region and are mostly vested with states such as Jharkhand, Orissa, and West Bengal. This region has 173.12 billion tons (Bt) (62.7 percent) of reserves in its inventory and has 293 mines owned by Eastern Coalfields Ltd., Bharat Coking Coal Ltd., Central Coalfields Ltd., Mahanadi Coalfields Ltd., and some private players. This region produced around 232.554 metric tons (Mt) of coal in FY2010/11.
- In the western region, coal reserves are found in Chhattisgarh, Madhya Pradesh, and Maharashtra. The region has 78.97 Bt (28.6 percent) of coal reserves with

186 mines owned by Western Coalfields Ltd., South Eastern Coalfields Ltd., and others, and the region produced 223.631 Mt of coal in FY2010/11.

- The southern region ranks third with 22.01 Bt (8 percent) of coal reserves found mainly in Andhra Pradesh. It has 67 mines owned by Singareni Collieries Company Ltd. and some others, and the region produced 51.333 Mt of coal in FY2010/11.

Although pooling seems difficult in physical terms (because of logistical challenges), pooling is much easier in pricing terms (for example, weighted average of import and domestic costs). However, the effects are likely to be highly unequal. Power generators—generally public sector generators—that currently have access to cheap domestic coal will suddenly face a hike in their input costs. And generators currently reliant on expensive, imported coal—generally private-sector generators—will benefit from a lower average price. Price pooling is a pure redistribution from the state sector (and eventually the consumer) in favor of the private sector power producer.

One way of mitigating the across-the-board negative effect of pooling could be a requirement that power plants that actually received the physical supplies of blended imported and domestic coal (meaning that the plants did not suffer from logistics constraints) should pay the blended price. Other plants that were logistically unable to receive blended coal should not face the pooled price.

Otherwise, as an extreme example, pit-head-based power plants that face no logistics costs and have no need for imported coal would be subsidizing plants that are entirely dependent on imported coal. Pit-based-plants would be forced to give up their cost advantage and pay a higher cost of fuel, so that the plants importing coal could pay a lower cost.

Ninety percent of domestic coal supplies used in the power sector are estimated to be consumed by plants that were commissioned before March 2009. Presumably these plants also supply the majority of electricity consumers, because only a handful of plants were commissioned in 2010 and 2011 (and almost none in 2012). Pooling would likely suggest fuel price rises (and tariff hikes) for the majority of power consumers.

Some order of magnitude of the problem to be confronted is provided by the following statistics:

- In August 2011, a study by Prayas Energy Group (2011) found approximately 590,000 MW of coal projects in the pipeline that had received or were expecting imminent environmental approval. However, since the release of the Prayas study, a major slowdown has occurred among planners of new coal capacity.
- As of May 31, 2012, 41,650 MW of projects had been deferred (that is, progress was on hold), and an additional 22,420 MW of projects had been cancelled.

The reasons for the slowdown were multiple: (a) dramatic rises in the cost of imported coal in 2012; (b) insufficiency in domestic coal output; (c) an

unfolding domestic crisis over the integrity of the coal allocation process, known as “Coalgate”; and (d) difficulties in obtaining financing. Nevertheless, 87,122 MW of projects were still under construction as of May 31, 2012, and an additional 68,200 MW of projects were in advanced development, having achieved most milestones (permits, water, land, coal, and financing).

Allocation of the scarce low-cost domestic coal among multiple claimants is complicated. Avoiding difficult choices in doing so is impossible.

Notes

1. The three fast-track projects commissioned were phase 1 (740 MW) of the 2,184-MW combined cycle gas-based Dabhol Power Project in Maharashtra (phase 2 was 90 percent complete when Enron exited India); the 235-MW combined cycle gas-based Jegurupadu Power Project in Andhra Pradesh; and the 250-megawatt lignite-based Neyveli Thermal Power Station of ST-CMS Electric Company Private Ltd. in Tamil Nadu.
2. Appendix B contains a chronology of events in the Dabhol Power Project.
3. The cost-plus tariff is determined on the basis of total project capital cost and the norms specified in the terms and conditions of tariff. The tariff has two components: (a) annual fixed charges consisting of interest on loan, depreciation, operation and maintenance cost, return on equity, and interest on working capital; and (b) energy charges covering fuel cost based on plant-load factor norms. The anticipated lower tariffs as a result of efficient private generation actually were higher than for the state-run plants because the costs were well above the benchmarks.
4. For example, procedures for ash utilization have undergone significant amendments over the years, with mandatory use of fly ash required in user industries within a given radius of power plants, permission for commercial sale of fly ash, and so forth.
5. The statutory advice is available at http://www.cercind.gov.in/2010/Advice_Gov/timeframe_tariff_based_16-09-2010.pdf. For a detailed analysis, visit the CERC website, <http://www.cercind.gov.in/>.
6. CIL introduced coal distribution through e-auction to provide access to coal for buyers who are unable to source coal through an available institutional mechanism (Spot e-Auction) and for buyers who wish to have an assured supply over long periods (forward e-auction). For this purpose, 10 percent of the annual production of CIL is marked for e-auction.
7. Appendix D contains a detailed analysis of fuel risks.

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Private Sector Participation in Transmission

Key Messages

- The private sector has a limited presence in the Indian transmission sector, which is dominated by the national company PowerGrid Company of India Ltd. (PGCIL) for interstate lines, and by state-owned transmission companies for intrastate lines.
- Apart from the joint venture (JV) approach, there are two optional modalities for a state seeking private investment in transmission on a competitive basis: the Ministry of Power (MOP) model and the Planning Commission (PC) model.
- The MOP model is design-build-own-operate, and the line is owned by the private sector in perpetuity; the bid variable is the levelized tariff. Prior transmission experience is not required.
- The PC model is design-build-finance-operate-transfer (DBFOT) and includes a tariff that is specified by the state transmission utility, with a viability gap grant from the central government, which is the bidding variable (that is, reverse auction where the winner requires the least viability gap grant). Prior transmission experience is preferred.
- For intrastate projects, a line built under the PC model has been commissioned in Haryana, whereas the line tendered out in Rajasthan under the MOP model has experienced delays on account of Rajasthan Electricity Regulatory Commission (RERC) setting aside the bid process initially, because it deemed that due process had not been followed under Section 63 of the Electricity Act of 2003. RERC revised its order in June 2012 and cleared the projects subsequent to direction from the Appellate Tribunal for Electricity based on an appeal by the Bid Process Coordinator.
- Some transmission investors' projects are negatively affected by fuel shortages upstream at generation plants, which is causing uncertainties around the possibility and timeframe for commissioning of such projects, thus threatening the feasibility of associated transmission evacuation projects.
- Overall, it is too early to judge the experience of private sector investment in transmission, because most lines (other than JVs) have been operational for a short time or are not yet complete.

Chronology of Private Sector Participation in Transmission

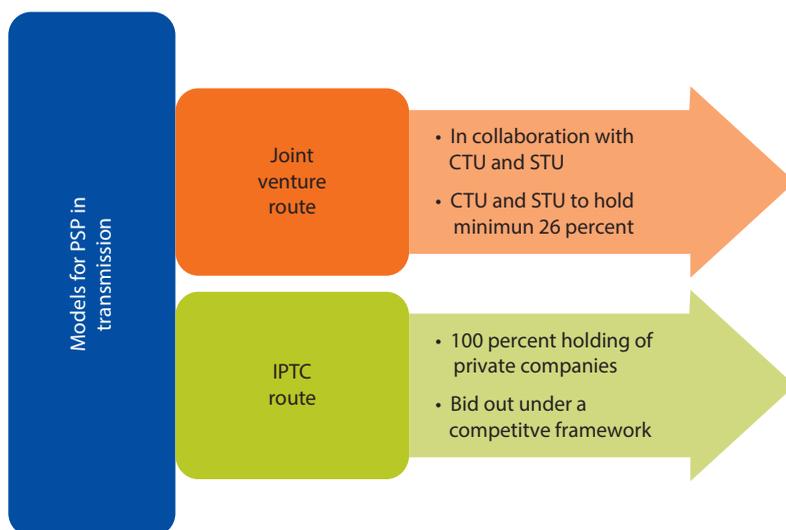
Given the scale of capacity additions planned in generation, particularly in the private sector, private participation in transmission is a logical corollary. With the success achieved in generation through ultra mega power plants (UMPPs), which were procured by using tariff-based competitive bidding, the central government envisaged attracting private investment for certain identified new transmission projects on a similar basis, in keeping with Section 63 of the Electricity Act of 2003. Guidelines were framed for interstate transmission projects, with the expectation that these could later be adopted by the state governments as well for their intrastate projects.

Legal Framework for Transmission Business

The Electricity Rules (Amendment) Act of 1998 for the first time authorized transmission to be a separate activity, making way for a transmission license, and brought in the legal framework enabling private sector participation (PSP). To pave the way for private sector investment, the central government issued guidelines in January 2000 for two routes of PSP in transmission (figure 3.1):

- *Joint venture*: The central transmission utility or the state transmission utility shall own a minimum of 26 percent of the equity in the JV, with the private participant holding the balance.
- *Independent power transmission company*: Transmission projects are bid out under a competitive process with the private developer holding 100 percent of the equity in the project.

Figure 3.1 Models for Private Sector Participation in Transmission



Note: CTU = central transmission utility; IPTC = independent power transmission company; PSP = private sector participation; STU = state transmission utility.

The Electricity Act of 2003 outlined provisions for a transmission license to be granted by the Central Electricity Regulatory Commission (CERC) for all interstate transmission projects and by the state electricity regulatory commissions for all intrastate transmission projects. Sections 61 and 62 of the Electricity Act of 2003 also provided that, where the tariff had been determined through a bidding process, the appropriate regulatory commission “shall adopt the tariff so determined.”

The National Tariff Policy of 2006 refers to private investment in the transmission space through a competitive bidding process. To further the intent of the National Tariff Policy of 2006, the MOP, in exercise of its authority under Section 63 of the Electricity Act of 2003, issued guidelines for tariff-based competitive bidding in transmission, which included model bidding documents containing a model project agreement. The guidelines issued by MOP provide for the appointment of a bid process coordinator by the central or state government to manage the bidding process. In October 2010, the PC, which had developed a series of model contracts for various public-private partnership (PPP) transactions, published its own model transmission agreement that was envisaged to be used for intrastate transmission projects.

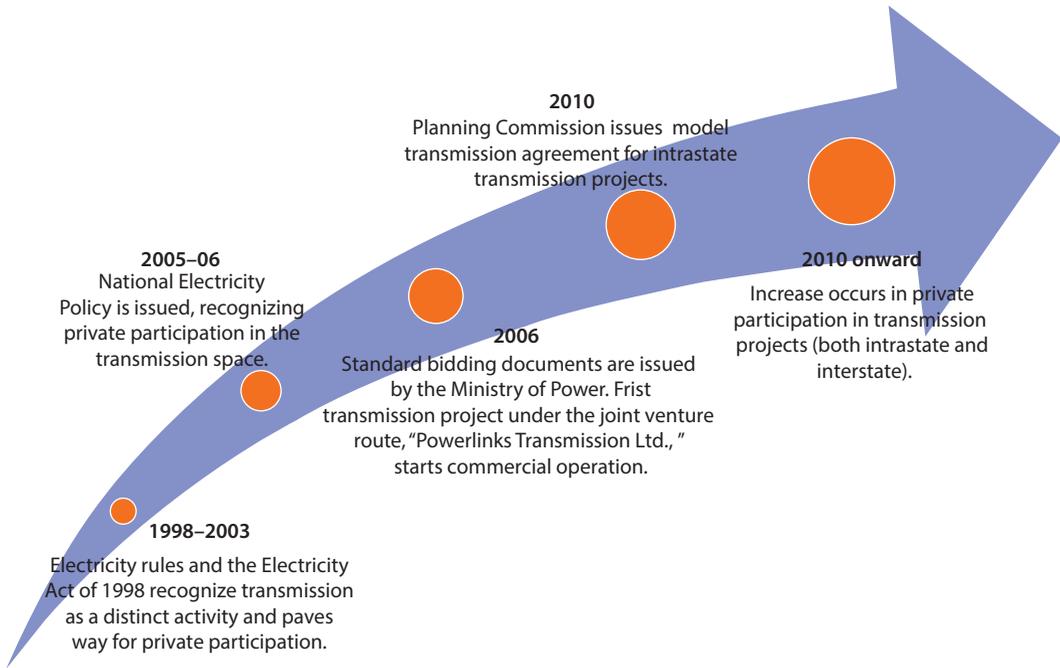
Both models (MOP and PC) have a similar scope, that is, attraction of private participation to transmission investment; however, the models vary in their approaches to achieving their objectives and in their perceptions of the transmission sector. Whereas the MOP model considers private participation to be commercially viable, the PC model envisages the use of viability gap funding (VGF).

The two models treat project ownership differently. The PC approach requires the title in the transmission assets to revert to the relevant utility at the end of the concession period. The MOP model does not provide any express provision for change in asset title beyond the concession period, that is, the private investor continues to own the transmission assets in perpetuity.

Besides the MOP and PC models, the JV route (which is a classic PPP arrangement) has also been explored. A few utilities have chosen the JV route with positive results. Figure 3.2 provides a summary of milestones for PPP in the power transmission sector.

Private Participation Experiences

The first transmission line investment through private participation took place in 2006 as a JV between Tata Power and Power Grid Corporation of India Ltd. (POWERGRID) for implementing the Indo-Bhutan power transmission line (Powerlinks Transmission Limited). The project partner was chosen by the PGCIL, through an international competitive bidding route; although Powerlinks was very successful in meeting its objectives, PGCIL did not take up a second project under this mode. In yet another variation of the JV model, POWERGRID entered into several project-specific JVs with generation project developers for joint development of transmission evacuation projects associated with specific generation projects. The latest development is in the form of tariff-based

Figure 3.2 Private Sector Participation in Transmission

competitive bidding for transmission projects, which has been made mandatory for interstate projects bid after January 5, 2011 and for intrastate projects after January 5, 2013.

Projects Using the Joint Venture Approach

A summary of the JVs entered into by PGCIL is outlined in table 3.1. The ownership stakes (percentage) outlined in table 3.1 are the ownership portion controlled by PGCIL.

In addition to the above six transmission projects under the JV route initiated by PGCIL for interstate transmission, state-level examples of JV partnerships between the public and private sectors also exist. Maharashtra State Transmission Company has developed two projects under the JV route, and its holdings in each of these are outlined in table 3.2.

Projects Using the Independent Power Transmission Company Approach

Pursuant to Section 5.1 of the National Tariff Policy, the IPTC route (that is, no public ownership and tariff-based competitive bidding) has also been tried in several interstate and intrastate transmission projects. Table 3.3 summarizes the outcomes of the bid process for interstate IPTC projects, showing the lowest levelized tariff quotes of the winning bidders.

Table 3.1 Summary of Joint Ventures Entered Into by PGCIL

<i>Company</i>	<i>Ownership as of March 31, 2011 (%)</i>
Powerlinks Transmission Ltd.	49.0
Torrent Power Grid Ltd.	26.0
Jaypee Powergrid Ltd.	26.0
Parbati Koldam Transmission Company Ltd.	26.0
Teestavalley Power Transmission Ltd.	26.0
North East Transmission Company Ltd.	24.9

Source: World Bank 2012.

Note: PGCIL = PowerGrid Company of India Ltd.

Table 3.2 Projects Developed under the Joint Venture Route by Maharashtra State Transmission Company

<i>Company</i>	<i>Ownership (%)</i>
Jaigad Power TransCo Ltd. (with JSW Steel Ltd.)	26
Maharashtra Eastern Grid Power Transmission Company Ltd.	26

Source: World Bank 2012.

Projects Using the Planning Commission Approach

In 2010, the Haryana state utility company, Haryana Vidyut Prasaran Nigam Ltd. (HVPNL), used the PC's model transmission agreement in the process of awarding an intrastate transmission project to Jhajjar KT Transco Private Ltd., an India-based special purpose vehicle (SPV). The project involves approximately 100 kilometers of a 400-kilovolt (kV) direct-current transmission line, plus two 400 kV substations. Because the tariff levels were prescribed in the bidding documents, the main bidding parameter was the extent of VGF to be provided to the SPV. At the end of the concession period, ownership of the transmission assets will revert to HVPNL.

Current Models for Private Participation

As indicated, two models exist for awarding projects to private sector participants under a competitive bidding framework:

- PC model (which has been used for the HVPNL intrastate project)
- MOP model (all inter-state projects and two intra-state lines in Rajasthan)

The PC has been responsible for furthering the concept of PPP infrastructure projects. In 2005, the Cabinet Committee on Economic Affairs (CCEA) issued detailed guidelines for the approval of PPP projects. The guidelines apply to all PPP projects in all sectors that are sponsored by the central government, central public sector undertakings (CPSUs), and statutory authorities or entities under their administrative control. This process requires projects to be approved by the

Table 3.3 Summary of Bid Process Outcomes for Interstate IPTC Projects

<i>Project</i>	<i>Award year</i>	<i>Bidder</i>	<i>Levelized tariff (Rs, millions/year)</i>	<i>Estimated project cost (Rs, millions)</i>
East North Interconnection Company Ltd.	October 2006	Sterlite Technologies	1,188.00	8,000
		Lanco Deepak Consortium	1,676.90	
		Reliance Power Transmission Ltd.	2,400.00	
Talcher II Transmission Company	April 2010	Reliance Power Transmission Ltd.	1,440.00	14,000
		L&T Transco Private Ltd.	2,094.00	
		Bidder (name unavailable)	2,510.00	
		Sterlite Technologies	2,279.90	
North Karanpura Transmission Company	May 2010	Reliance Power Transmission Ltd.	2,580.00	27,000
		Lanco Deepak Consortium	3,831.00	
		L&T Transco Private Ltd.	4,432.00	
		Sterlite Technologies	5,376.00	
Raichur Sholapur Transmission Company Ltd.	January 2011	Patel Engineering, Simplex Infrastructure, and BS Transcomm	294.00	3,000
		Lanco Infratech	315.90	
		Sterlite Transmission Projects Ltd.	367.20	
		Reliance Power Transmission Ltd.	479.90	
Bhopal Dhule Transmission Company Ltd.	February 2011	Sterlite Transmission Projects	1,995.30	9,000
		Ashoka ICOMM Consortium	2,184.80	
		Lanco Infratech	2,448.90	
		Soma Enterprises	2,590.20	
		L&T Transco Private Ltd.	2,807.50	
Nagapattinam Cuddalore	March 2012	PGCIL	987.02	11,000
		L2	1,529.44	
		L3	2,082.51	
		L4	2,085.92	
		L5	2,389.54	

Source: World Bank 2012.

Note: IPTC = independent power transmission company; L = lowest bidder; PGCIL = PowerGrid Company of India Ltd.

Public Private Partnership Approval Committee (PPPAC), comprising secretaries of the Department of Economic Affairs (in the chair), PC, Department of Expenditure, and Department of Legal Affairs and the secretary of the department sponsoring the project.

The MOP has maintained that projects under Section 63 of the Electricity Act of 2003 fall outside the requirements for being referred to the PPPAC. This position is based on two contentions. First, the MOP argues that the provisions under the Electricity Act of 2003 provide for specific guidelines to be issued by the central government for projects that are bid out under Section 63 of the Electricity Act of 2003 and that as long as projects are bid out in conformance with these guidelines, the projects need not follow the PPP guidelines outlined by the CCEA. Second, the MOP has also noted that the CCEA guidelines apply to projects sponsored by the central government, CPSUs, or statutory authorities

under the central government. In the case of projects bid out under Section 63, the concession agreements are signed with distribution utilities and these projects are neither sponsored by the central government nor concessioned by any of the central government authorities or CPSUs. As such, the MOP has followed an approach independent of that specified by the CCEA as far as approval by the PPPAC is concerned.

There are some similarities in the models. Under both models, the private investor arranges financial resources and undertakes construction, maintenance, and operation of the transmission line for an annual transmission charge paid by the beneficiary. This approach suggests that the private investor takes all project-related risks. However, in terms of eligibility requirements (qualifications of bidders), both models treat interested private investors differently. Whereas the MOP model does not require experience in transmission projects, the PC model provides a benefit to private investors who have previous experience specifically in transmission. Once construction is complete, both models also require the private investor to be responsible for the operation and maintenance of the project, though the private investor or a third party hired by the project developer can undertake this operation and maintenance. A comparison of the models is summarized in table 3.4.

To date, attracting private investors for either model has not been difficult. The Rajasthan project used the MOP guidelines to award its IPTC transmission lines competitively, whereas the Haryana project used the PC approach. Although it is too early to tell whether there is any difference in performance or outcome based on the approach selected, significant procedural difficulties in the Rajasthan case have resulted in delays and unexpected costs for the developer. In contrast, the line constructed under the PC model has been successfully commissioned. However, two cases alone do not permit any conclusions to be drawn. The provision of central government VGF for projects adopting the PC model is an obvious attraction for state governments to opt for this route, because it results in a lower burden for the state government and the utilities. However, how long the central government VGF provision can continue is unclear, given that it is provided only for transmission projects, along the electricity value chain straddling generation to distribution. Transmission in general has traditionally been viewed as the least risky portion in the electricity value chain and has not struggled to recover its full costs from beneficiaries. The provision of VGF for transmission in isolation thus raises doubts on its continuity over a longer period, given in particular the demands for VGF from so many competing PPP projects across the country.

At present, the primary drivers for private interest in bidding are affected by uncertainties in the generation sector; revenues for transmission become risky when the generation project, which will need the transmission line to evacuate power, itself faces delays or uncertainties. Also, only a limited number of projects are completed, and they have not been in operation sufficiently long for comment on their performance. Nevertheless, appendix E contains some lessons learned on some emerging issues for transmission investors.

Table 3.4 Comparison of MOP and PC Models

<i>Parameter</i>	<i>Development model</i>	
	<i>Planning commission</i>	<i>Ministry of Power</i>
Regulatory approval	Prior regulatory approval is required, because the model sets a prescribed tariff for the transmission project.	No prior approval is required if the MOP standard bidding documents have been used.
Viability gap funding	The procuring utility provides support to the construction and the operations and maintenance costs of the project through viability gap funding (VGF).	VGF is not deemed necessary for the project. The MOP model requires all construction costs and the operation and maintenance costs to be borne by the private developer.
Asset ownership	At the end of the concession period, the asset is transferred to the procuring utility. The project is developed under the DBFOT (design-build-finance-operate-transfer) model.	There is no provision for transfer of the asset. The project company always owns the asset. Project is developed under the BOOM (build-own-operate-manage).
Bidding criteria	The bid parameter is the lowest financial grant (VGF) required by bidders to the project.	Levelized annual transmission charges are quoted by the bidders to the project. This annual transmission charge is inclusive of project capital cost and the operation and maintenance cost for the project life. Bidders have the option of quoting the transmission charges on a split basis, reflecting variable and fixed costs.
Eligibility	A natural person, single entity, or group of entities in consortium can bid for the project.	A company or a consortium of companies can bid for the project.
Project cost	The bid coordinator indicates estimated project cost.	Project cost indication is not provided.
Timeframe for completion of RFQ stage	150 days	75 days
Number of bidders	No more than six bidders are to be considered.	There is no restriction on maximum number of bidders. Minimum number of bidders prescribed for ensuring competitiveness is two.
Noncore revenue	Revenue from real estate development or use of transmission poles for advertisement is considered.	Such provisions are not included.

Source: World Bank 2012.

Note: MOP = Ministry of Power; PC = Planning Commission; RFQ = request for qualification.

Private Sector Participation in Distribution

Key Messages

- Financial weakness of the distribution segment has threatened private investment in power in India along the entire value chain since the early 1990s, because distribution companies (discoms) have remained dependent on subsidies, which has, in turn, made generation investors nervous about discoms' future ability to pay for power.
- Poor operational efficiency, high levels of theft, and obsolete network equipment have led to average levels of aggregate technical and commercial (AT&C) losses of around 27 percent, among the highest in the world. This level means that nearly one-third of power purchased by the discom from the generation company is lost before revenues can be collected.
- On average, an estimated one-third of customers do not pay (because of theft) and close to another one-third do not have to pay (because of free electricity provided to agriculture). Therefore, only an estimated one-third of customers are paying for the two-thirds of power that is supplied relative to what is purchased by the discom.
- In this scenario, raising tariffs for full cost recovery from the few customers who are paying would be a politically sensitive and difficult approach.
- Although a few discoms are performing well, the majority are in poor financial health; discoms in five states account for more than 60 percent of the total losses. Total financial losses by utilities are estimated at US\$20 billion before subsidies; and after an allowance of US\$7 billion in subsidies from state coffers, there is still a US\$9 billion financial gap.
- Commercial banks are already heavily exposed to the distribution sector; the Ministry of Power introduced a rating system for discoms in March 2013 to provide guidance to commercial banks and to limit further exposure.
- Distribution privatization occurred in Orissa and Delhi before passage of the Electricity Act of 2003. Subsequently, private involvement has been

competitively invited through a distribution franchise arrangement instead of outright privatization.

- There has been rich experience with distribution franchising in urban and rural areas, and much has been learned despite a relatively limited number of attempts. Important lessons have been learned—particularly from failed urban distribution franchising efforts—and such lessons can be built into the future design of bids to attract private participation in distribution.
- A further model, developed at the Planning Commission, is currently at the discussion stage. It would offer viability gap funding to a competitively selected concessionaire, with exclusive use of the distribution network for 25 years, appropriate incentives and penalties, and recognition of two categories of customers (open access and regulated).

Distribution Performance and Chronology of Private Sector Participation in Distribution

Starting with the reforms in the 1990s, through to the latter half of the 11th Five-Year Plan (2007–12), the weak financial performance of the distribution segment in India has threatened repeatedly to derail private sector investments across the entire value chain. The distribution segment is the intake point for revenues from customers; it must be used to cover costs and provide a return on investment to all parties in the value chain. Discoms pay to purchase bulk power and then sell it to retail customers. If discoms are unable to cover their costs, they must be granted subsidies to cover the gaps, and this practice is perceived as unsustainable in the long term (and therefore risky) by private investors and their lenders.

Probably largely because of political interference from the state level, the distribution segment continues to remain in the stranglehold of state-owned utilities. Tepid attempts at introducing private participation through franchising have yielded modest results across the board, though the attempts have made important differences in some urban areas where they have been successfully introduced, because of political will. In any case, franchising has not yet been attempted on a scale that can have transformative effect. Because the introduction of franchising automatically excludes the continued use of electricity as a tool of political patronage within the franchise area, there is a strong connection between the political will to reform the sector and the introduction of a competitively awarded distribution franchise.

The most acute problem facing the Indian power sector is the weakening finances of distribution utilities, particularly in the larger states,¹ and the widening gap between their average tariff to end users and their cost of supply. The key causes of this problem are as follows:

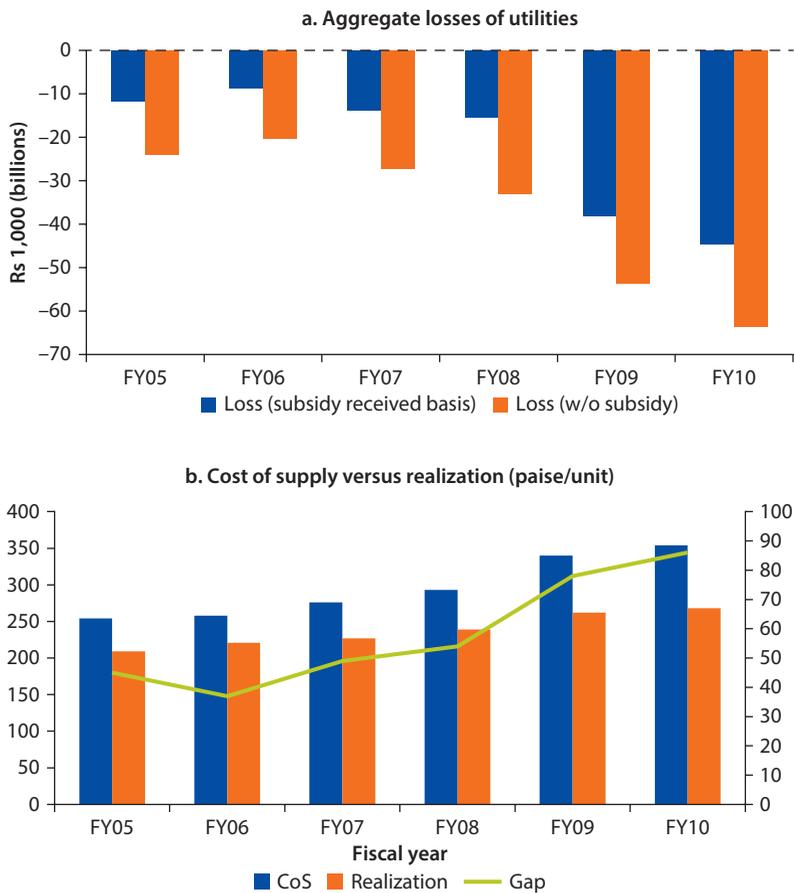
- Nonapproval of expenses by state regulators because of shortfalls by utilities in achieving efficiency targets
- Populist and politically influenced tariff determination (some states have gone without tariff revisions for years)

- An inability by utilities to collect the full amount of revenues that are owed to them, because of commercial inefficiencies (that is, even when the tariff is too low, utilities cannot manage to collect all revenues they are entitled to collect at that low tariff)
- Inability of utilities to incur necessary capital investments for efficiency improvement and loss reduction as a result of poor financial health

In combination, these factors have produced a vicious cycle of financial decline.

With increasing costs of power and continued poor operational efficiencies, the accumulated financial losses of distribution utilities have been on the rise since fiscal year (FY) 2005/06 and had already reached Rs 928 billion (US\$15 billion) by FY2011/12 (without considering subsidies). By FY2011/12, the accumulated losses had crossed more than Rs 1,000 billion (US\$16 billion). Also, as can be seen in figure 4.1, the gap between the average cost of supply and

Figure 4.1 Average Cost of Supply and Average Revenue Realization per Unit Sold



Source: Power Finance Corporation Ltd. 2013.

Note: CoS = cost of supply; FY = fiscal year.

the average revenue realization per unit sold at the national level had worsened to 107 paise (US\$1.73 cents) per unit (from a low of 37 paise [US\$0.60 cents] per unit over the corresponding period). Such an increase in the per-unit revenue realization gap for distribution utilities is mainly attributable to continued high technical and nontechnical (AT&C) losses, an increase in costs (especially power purchase costs), and noncommensurate adjustments in tariffs.

The increase in costs was primarily led by the sharp increase in the price of fuel for generation toward the end of the previous decade. The Central Electricity Regulatory Commission has approved a substantial increase in wholesale tariffs for central generation plants for the period 2009–14. The second important reason for the sharp increase in costs is the revision of pay for all government (and government enterprise) employees, in accordance with the recommendations of the Sixth Pay Commission. Although passing on the increased costs for the generation and transmission utilities to the distribution utilities has been easier because of the lower sensitivities involved (that is, all public agencies charging each other a higher price), the tariff for the distribution segment where all costs converge—and must be recovered from the end users—has not been revised commensurately, mainly because of political pressures. This situation has led to exponential growth in losses for the distribution utility.

There is a valid reason, other than political pressures, for distribution utilities to hesitate about approaching the regulator for permission to increase tariffs. One may well ask why the burden for high levels of inefficiency and losses should be borne by the end users. Conversely, if a utility acknowledges that it loses about one-third of the power purchased on the way to delivering it to the final customer, how can anyone be sure that a higher price paid by the customer would not lead to bigger governance problems—that is, to more of the customer's money finding its way into the leak? Serious distribution reforms resulting in improved commercial and operational performance, and higher technical efficiency (loss reduction), should be implemented at once, rather than allowing distribution utilities to consume ever higher subsidies from state coffers to balance their books. However, despite the worsening financial situation of the distribution utilities, distribution reforms have taken a back seat in several states. Most state governments are reluctant to permit tariff revisions and are also unable to enforce sustainable efficiency improvements under government ownership in situations where performance and remunerations have traditionally not been linked.

The economic success of India and the associated buoyancy in the fiscal condition of many of its states during the latter part of the 10th Five-Year Plan (2002–07) and the early part of the 11th Five-Year Plan (2007–12) made it possible for state governments to sustain higher levels of financial (subsidy as well as equity) support to the utilities. This support, along with high levels of financial support under the Accelerated Power Development and Reforms Programme (APDRP) and Restructured APDRP (R-APDRP) from the central government, contributed to state governments and utilities postponing or backtracking on essential bold and radical reform measures. As a result, India is faced with a veritable “lost decade” of distribution reforms during which inefficiencies have

become chronic and private participation in this segment has been overlooked in all but a few cases of distribution franchisees (DFs) over the past 10 years.²

The central government continued the APDRP program over the 11th Five-Year Plan period in the form of the R-APDRP initiative by making provisions for capital investment-led efficiency improvements in the power distribution segment with a total outlay of more than Rs 550 billion (US\$8.88 billion). R-APDRP consists of two main parts. Part A focuses on the introduction of information technology initiatives and creation of reliable baseline data for measuring efficiency improvements. Part B focuses on actual network interventions to bring in the targeted efficiency improvements. R-APDRP projects undertaken by the various state utilities are mostly in the part A stage at present. The weak institutional endowment of distribution utilities in several states imposes constraints on the efficacy of the program. Private distribution utilities (such as North Delhi Power Ltd., Brihanmumbai State Electricity Supply (BSES) Rajdhani Power Ltd., BSES Yamuna Power Ltd., Calcutta Electric Supply Corporation, Tata Power Company Ltd., and Brihanmumbai State Electricity Supply, which have much better institutional capacity and incentives) in places such as Delhi, Kolkata, and Bhiwandi are not covered under the R-APDRP program.

Additionally, the central government initiated an ambitious program for achieving 100 percent village electrification under the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) scheme, launched in April 2005, with a revised total outlay of Rs 439.54 billion (US\$7.1 billion) spread over the 10th and 11th Five-Year Plan periods. Under this program, 112,228 villages and 27,755,314 households have been electrified to date—the grid has reached the villages. The program requires that at least 10 percent of the households in a village have access to an electricity connection, but it does not specify how many hours a day power must be available. In fact, the central government considers that its responsibility is to extend the grid, while noting that the states' responsibility is to supply power to that grid (but because of severe power shortages at the state level, those rural connections remain unenergized for large periods of time). Yet the sudden increase in access to electricity connections in the rural areas, owing to the large-scale electrification (capital expenditure) undertaken as a part of the RGGVY scheme, has led to rapid growth in the number of subsidized consumers in several states. This growth has added further to the immediate need for revenue enhancement or subsidy support mechanisms for the state distribution companies.

Private participation in distribution has long been considered one of the most effective solutions to resolving the efficiency issues in distribution. The private distribution utilities in Kolkata, Mumbai, Surat, and Ahmedabad, (which have been in private hands since before Indian independence and are hence referred to as the legacy private companies), with their exemplary performance in efficiency and customer service measures, have been recognized as obvious examples of private efficiencies in the Indian environment. In this context, despite immense opposition from employees and unions and certain sections of the political community, privatization of power distribution was taken forward first in Orissa and then in Delhi.³ The outcomes of the privatization experience (as set out

Figure 4.2 Outcomes of the Privatization Experience

Prereform	1997	2002	2007	2009	2010–11	2011–12
CESC, AECL, SECL, BSES, NPC, TPC	Orissa privatization	Delhi privatization	Bhiwandi and Nagpur DFs	Kanpur and Agra DFs	Nagpur, Aurangabad, and Jalgaon DF	Ujjain, Sagar, Gwalior in MP, Jamshedpu, and Ranchi in Jharkhand
Private utilities have been existence even before the reforms.	Orissa was the first state to privatize the distribution utilities in postreform era.	Delhi privatized its distribution utilities in 2002.	Bhiwandi was the first DF to be awarded in January 2007. Nagpur DF bid process was scrapped.	Recently, UPPCL awarded its Kanpur and Agra circle to TPC; TPC started operation in Agra.	Spanco Ltd., GTL Infrastructure Ltd., and Crompton Greaves Ltd. awarded Nagpur, Aurangabad, and Jalgaon.	Essel Infra Projects Ltd., declared winner for 3 DF areas in MP, Ranchi, and Jamshedpur awarded to CESC and Tata Power.

Note: AECL = Ahmedabad Electricity Company Ltd.; BSES = Brihanmumbai State Electricity Supply; CESC = Calcutta Electric Supply Corporation; DF = distribution franchisee; NPC = Noida Power Company; SECL = Surat Electricity Company Ltd.; TPC = Tata Power Company; UPPCL = Uttar Pradesh Power Corporation Ltd.

in figure 4.2) have been mixed, and other state governments have lacked the political will to pursue an ownership transition from the public sector to the private sector systematically, despite the well-known problems of the status quo.

In view of the reluctance of states to proceed with outright privatization, following the experiences of Orissa and Delhi, another approach was needed to secure private involvement in distribution. With the promulgation of the Electricity Act of 2003, the legitimacy of the distribution franchisee (DF) concept became well established, because the act provided for appointment of any person to undertake distribution and supply on behalf of the licensee (that is, the state utility) within the licensee's area of supply.

Maharashtra, driven by the distribution losses being suffered in certain areas of the state, was the first to test the input-based franchisee approach in the Bhiwandi area. The success of this experience made Bhiwandi a good example for DFs. Unfortunately though, few distribution franchises have been pursued subsequently. Although Bhiwandi was a success, there were several failures too, highlighting the urgent need for a set of standardized approaches to franchisees based on the insights and lessons learned from these examples.

Comparative Highlights of the Privatization Experience of Orissa and Delhi

The Orissa and Delhi experiences of privatization for ailing discoms resulted in different outcomes and have been extensively cited as examples both for and against privatization in recent times (see appendix B for more information and volume 2 for a full case study of each). Unlike private participation in generation or transmission, which are typically greenfield ventures, private participation in

distribution involves taking over an existing system of networks, employees and customers (“brownfield”), and is therefore vastly more complex and sensitive. The expectations of existing customers must be managed, as well as those of existing workers in the utilities who perceive that they may be displaced by the new arrangements (and will therefore resist). The investors may require some initial hand-holding to prevent disruptions to either set of stakeholders that will create difficulties.

Specifically, the Orissa privatization experience has been widely studied⁴ and compared and contrasted with Delhi’s experience. Some of the key lessons are as follows:

- Private participation in an operating business, like distribution, requires all key public sector stakeholders to be aligned on the key expectations and risk-sharing arrangements with the private party. In Orissa, there was a wide disconnect between, on the one hand, the expectations of the regulator (the Orissa Electricity Regulatory Commission) and, on the other hand, the privatized distribution utilities (and, presumably, the state government, which managed the privatization process).
- The crucial period in a private participation process is the first few years immediately following handover to the new owner. Recognizing the complexity of the distribution business, both the state government and the regulator need to demonstrate flexibility and should be ready to provide all possible support to the private party to bring about changes, which have not been possible for years under public ownership or control. This point underscores the importance of transition period support, in the form of a safety net from the state government and the ability of the regulator to recognize realities on the ground and be flexible in adjusting the tariff regime.
- The Orissa privatization experience also outlines the need to structure as many controllable parameters up front as part of the transaction and through a bidding process, rather than leaving that aspect to the discretion of the regulator or the state government. The Delhi privatization process incorporated this lesson.
- Finally, for distribution, which is a public utility business, transaction frameworks need to provide for alternatives to replace an operator, in case the private operator should fail to discharge its duties or fail to meet the commitments integral to its bid. This was not present in the Orissa case, and the government had to take over operation of one of the discoms following privatization, upon the departure of the private operator.

Orissa versus Delhi Privatization Experience

The key benefit for the Delhi government when it undertook the electricity sector reforms was the live example of Orissa, which showed clearly that mere transfer of ownership to a private party was no guarantee for efficiency improvements and improved customer service levels. Nevertheless, it is essential to

Table 4.1 Outcomes and the Process Followed by Delhi and Orissa

<i>Parameters</i>	<i>Delhi</i>	<i>Orissa</i>
Targets	Yearly loss reduction targets were provided.	No targets were provided.
Bid parameter	Yearly AT&C loss reductions were for five-year period.	Highest bid was for 51 percent equity.
Financial restructuring	Clean balance sheets were provided to new entities.	Clean balance sheets were provided to new entities.
Transition support	Government provided subsidy for power purchase for five years.	Government did not provide any subsidy post-privatization.
Pre-privatization liabilities	Government retained all pre-privatization liabilities.	Pre-restructuring liabilities were held back in Gridco.
Tariff Setting	Government made the bid conditions binding on the regulator, the Delhi Electricity Regulatory Commission, which determined the tariff as per regulations.	The Orissa Electricity Regulatory Commission set tariffs based on aggressive loss reduction targets.
Return	Regulated return of 16 percent return on equity was subject to achieving loss reduction target. Transition to MYT began after the end of the five-year period.	Regulated return on equity is 16 percent on all investment. Transition to multiyear tariff regime occurred from 2004 onward.
Outcome	The loss level was reduced considerably, with high consumer satisfaction.	One investor in the four privatized distribution companies abandoned it after two years. The loss level continues to be high, with low consumer satisfaction.

Source: Deloitte research.

Note: AT&C = aggregate technical and commercial; MYT = multiyear tariff.

understand the difference in terms of the outcomes and the process followed in these two cases for any future initiatives (as outlined in table 4.1), because the outright privatization model has not been subsequently attempted in India.

What Occurs Next on Distribution Reforms?

There have been no privatizations since those in Orissa and Delhi, and there has been limited distribution reform overall since passage of the Electricity Act of 2003. Yet utility finances have continued to worsen considerably to a level that has been characterized at times as India's sub-prime crisis. Especially in the past three to four years, the problem has attained mammoth proportions with the annual financial gap now at approximately US\$16 billion prior to subsidies (Ghosh, Majumdar, and Kadam 2012). Even after one considers subsidies paid out to utilities from the state exchequer (most often not paid on time), the deficits are approximately US\$7 billion per annum. For an overall perspective, the financial deficits of the sector before subsidies are equal to more than half the aggregated annual budgets of the states of Uttar Pradesh, Maharashtra, Rajasthan, Madhya Pradesh, and Bihar, five of India's most populous states.

The poor shape of distribution finances has several adverse effects. At the first level, it affects the utilities that are unable to pay for their costs and to make the investments that are required to serve customers. Utilities are also not able to pay

for power purchases even when electricity is available in the markets (preferring to resort to power cuts instead), resulting in poor quality of supply on the one hand and inadequate capacity utilization on the other in generating stations. This poor supply and utilization further affect sector finances.

The distribution utility bailout of October 2012 (Financial Restructuring Scheme of State Distribution Companies) is unlikely to resolve the long-term fundamentals of the liquidity crisis in the power sector. Although the states of Tamil Nadu, Rajasthan, Haryana, Uttar Pradesh, Jharkhand, Bihar, and Andhra Pradesh are likely to benefit under the scheme, at best, the bailout will benefit private investors' risk perceptions temporarily by reducing the debt loads of the utilities in the short term and improving cash flows. However, without fundamental changes in how business is done, it is likely to be only a matter of time before another bailout is required.

Distribution franchising seems to be the only innovation in distribution that seeks private sector involvement in an area that has substantially remained in the purview of state distribution utilities. However, the franchise approach has significant drawbacks, some of which are attributable to the fact that the franchisees are not license holders. Instead, the licenses remain with the state utility companies, which grant the franchises on a competitive basis (just as the private generators are competitively selected by the distribution utilities acting in their capacity as power procurers).

This book has devoted the bulk of its analysis to DF models because distribution is the cutting-edge segment of the power sector value chain for which the most work is still needed to improve overall performance. In view of the resistance by state authorities to wider adoption of outright privatization, it is important to ensure maximum value addition through the DF approach. There have been some successes and failures, all of which contain important lessons for successive rounds of bidding for franchisees. There are still far too few success stories of distribution franchising, and the author believes that the key to improving sector performance lies in creating more and better franchise agreements. The remainder of this chapter on distribution is, therefore, devoted to a detailed presentation and analysis of DF models for rural and urban areas.

DF Models

Although the urban Bhiwandi transaction has become the byword for this model (see appendix H, box H.1), one must recall that the DF model found its genesis in India in the context of improving access to electricity for rural communities. Rural areas were the focal point for attracting private parties, because the utility had limited reach in this area. It was thus envisaged that local community organizations (considered to fit the description of private parties) could take responsibility for small segments of the distribution system in rural or remote areas and carry out activities such as metering, billing, collection, and so forth. The distribution licensee would remain the state distribution utility, and the franchisee would essentially serve as the subcontractor to the licensee.

Table 4.2 Selected Provisions of the Electricity Act of 2003

<i>Provision</i>	<i>Extract from Electricity Act of 2003</i>
Section 14 (c)	"Provided also that in a case where a distribution licensee proposes to undertake distribution of electricity for a specified area within his area of supply through another person, that person shall not be required to obtain any separate licensee from the concerned State Commission and such distribution licensee shall be responsible for distribution of electricity in his area of supply"
Section 2 (27)	"Franchisee means a [person] authorized by a distribution licensee to distribute electricity on its behalf in a particular area within his area of supply"

Source: Ministry of Power, Government of India, New Delhi, http://www.cea.nic.in/reports/electricity_act2003.pdf.

The relevant provisions of the Electricity Act of 2003 (table 4.2) set out the legal position of DFs. The definition of franchisee under the act provides a considerable amount of flexibility in the choice of the scope of the activities that may be undertaken by the franchisee. Therefore, the range of services that can be delegated by the licensee to the franchisee can vary from any single role (for example, collection) to the full range of distribution activities in any particular area. Notwithstanding the extent of delegation of scope to the franchisee, the distribution licensee remains completely responsible to the state regulatory commission in the exercise of its duties and obligations for its entire license area of supply.

There is no discrimination between rural and urban franchisees with respect to the definition in the Electricity Act of 2003. However, different models are emerging, according to their suitability to a particular area (rural or urban) and also depending on the relative willingness of distribution utilities across the country to engage with franchisees. The basic different types of models being deployed in rural and urban areas are elaborated here.

Rural Distribution Franchisee Models

A decisive push toward rural franchisees was achieved because of the precondition in the RGGVY (centrally funded rural electrification) scheme that defines a franchisee as an entity empowered by the state either to develop or operate a generation and distribution system or to be ready to distribute electricity within an identified contiguous area for a prescribed duration and collect revenues directly from consumers. The basic objective of such franchisees is to ensure revenue sustainability and to help state utilities with the management of rural distribution networks that have significantly expanded under the RGGVY scheme (although most often there is insufficient power in the system to supply the networks that have been created in rural areas).

The rural areas, with characteristics that differ from those of the urban areas (which have high consumer-load density), call for a differentiated franchisee model. The consumer mix in rural areas is generally dominated by low-income households with nominal amounts of power consumption (because of a lack of appliances that require electricity). The utility's reach and physical presence in rural areas, especially in newly expanding networks, is limited, and billing and

collection are therefore often neglected. In many cases, state-owned utilities are content to recover only the government subsidy corresponding to their sale of electricity to subsidized consumers in rural areas, whereas the amount recoverable from consumers themselves is not acted upon because of high transaction costs. Therefore, the concept of franchisees is, in fact, welcomed by utilities in rural areas. The approach creates scope for the involvement of village- or town-level intermediaries as partners in metering, billing, and collection and also activities related to operation and maintenance (O&M) in which the required numbers of skilled workers are available.

In general, the lack of the requisite skill sets and financial capability at the rural or village level is a constraint that sharply limits the range of activities that can be outsourced by the state-owned utilities to rural franchisees. For example, it may not be possible for village- or panchayat-level personnel to undertake O&M and capital expenditure activities. However, those personnel can readily undertake revenue cycle management activities, such as new consumer registration, meter reading, billing, collections, and disconnections and reconnections. Also, although some states have vibrant community-based structures such as panchayati raj (local self-government) and women's self-help groups, other states are fairly weak in this regard, leading to variations in DFs across states.

Under the types of rural franchisee models that are being deployed across states, the range of activities varies from revenue collection to entire revenue cycle management to revenue cycle management plus O&M activities. Table 4.3 provides a comparison of the key characteristics of the different rural franchisee models on key parameters.

Table 4.3 Key Characteristics of the Different Rural Franchisee Models

<i>Model</i>	<i>Responsibility</i>	<i>Revenue or business model</i>	<i>Remarks</i>
Pure collection franchisee	<ul style="list-style-type: none"> Revenue collections, and disconnections and reconnections 	<ul style="list-style-type: none"> Margin or percentage on collections on achievement of target Incentive or disincentive for over- or underachievement 	<ul style="list-style-type: none"> Franchisee focuses primarily on collection efficiency.
Revenue collection-based franchisee	<ul style="list-style-type: none"> Revenue cycle management: billing, revenue collections, and disconnections and reconnections Handling of complaints New connections and disconnections 	<ul style="list-style-type: none"> Margin or percentage on collections on achievement of target Incentive or disincentive for over- or underachievement 	<ul style="list-style-type: none"> Franchisee is not a partner in T&D loss reduction. Franchisee focuses primarily on collection efficiency.
Input-based franchisee	<ul style="list-style-type: none"> Revenue cycle management: billing, revenue collections, and disconnections and reconnections Handling of complaints New connections and disconnections 	<ul style="list-style-type: none"> Supplied input energy measured at 11-kilovolt feeder level or DT level Franchisee payment of utility at a prefixed tariff on energy input 	<ul style="list-style-type: none"> Franchisee is a partner in AT&C loss reduction.

table continues next page

Table 4.3 Key Characteristics of the Different Rural Franchisee Models (continued)

<i>Model</i>	<i>Responsibility</i>	<i>Revenue or business model</i>	<i>Remarks</i>
O&M franchisee	<ul style="list-style-type: none"> • Revenue cycle management: billing, revenue collections, and disconnections and reconnections • Handling of complaints. • New connections and disconnections. • O&M of downstream network 	<ul style="list-style-type: none"> • Supplied input energy measured at 11-kilovolt feeder level or DT level • Franchisee payment of utility at a prefixed tariff on energy input 	<ul style="list-style-type: none"> • Franchisee is a partner in AT&C loss reduction. • Franchisee also contributes to reliability of power supply.
Rural electric co-operative franchisee	<ul style="list-style-type: none"> • Society funding, ownership, and operation of distribution system • All consumer-related activities 	<ul style="list-style-type: none"> • Supplied input energy measured at 11-kilovolt feeder level or DT level • Franchisee payment of utility at a prefixed tariff on energy input 	<ul style="list-style-type: none"> • State authorization is usually needed. • Franchisee is responsible for all facets of distribution in the given area.
Distributed generation-based franchisee	<ul style="list-style-type: none"> • Franchisee funding, ownership, and operation of generation and distribution system in remote areas not connected by grid • All consumer-related activities 	<ul style="list-style-type: none"> • Franchisee operation of independent business model with no transaction taking place with the incumbent distribution licensee 	<ul style="list-style-type: none"> • Model is mostly used in areas that are far from grids and lack feasible or viable options for connection.

Source: Deloitte research.

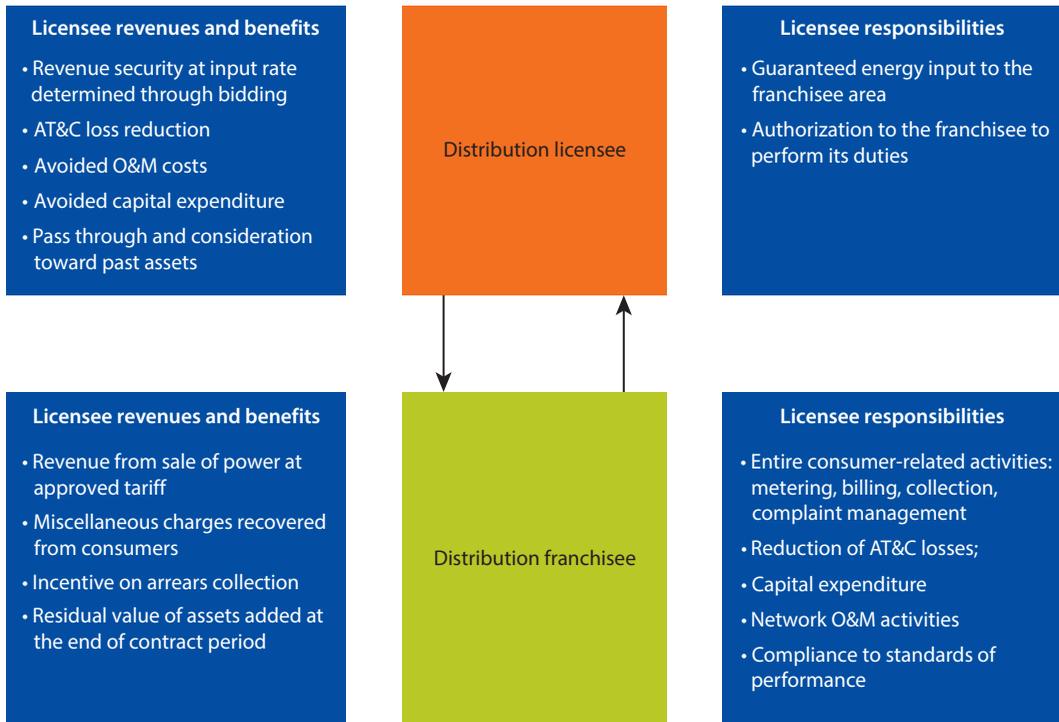
Note: AT&C = aggregate technical and commercial; DT = distribution transformer; O&M = operation and maintenance; T&D = transmission and distribution.

Urban Distribution Franchisee Models

After the success of the Bhiwandi input-based urban DF model, several states have commenced adoption of similar models. Franchises in Agra and Kanpur in Uttar Pradesh and in Nagpur, Aurangabad, and Jalgaon in Maharashtra have already been awarded to successful bidders, although it is too early to comment on the effectiveness of any of these.⁵ Several other states are attempting to implement similar DF models in identified areas or circles.

The urban areas are distinguished from the rural ones by their significantly higher load and network density and the mix of high-consumption, high-tariff consumers. The urban areas are more likely to be financially viable and to attract highly capable private parties, and therefore structuring full-service franchisees in these urban areas becomes feasible. Bhiwandi in particular was characterized by a predominantly industrial load (power looms), representing a more commercially viable type of customer base than the typical urban mix of predominantly residential customers. This commercial and industrial load in Bhiwandi, representing customers undertaking productive end-uses with the energy input, may be a partial explanation for the success of this initial urban franchisee experiment.

An urban full-service franchisee takes over all responsibilities of the distribution licensee in a given area and retains the revenue that it collects from the consumers in the area. The franchisee pays for the energy input into the area at a tariff that is normally determined through a competitive bidding process (the highest bidder for energy procured from the utility is selected as the franchisee).

Figure 4.3 The Roles and Responsibilities of the Franchisee and the Business Model

Note: AT&C = aggregate technical and commercial; O&M = operation and maintenance.

The roles and responsibilities of the franchisee and the business model are shown in figure 4.3.

In the typical input-based urban DF model, the franchisee takes over the defined area of supply (including assets and consumers) and pays for the energy input into the franchisee's area (which is electrically ring-fenced) and performs the entire gamut of activities ordinarily undertaken by the distribution licensee. Normally, the responsibilities of the franchisee include the following:

- The franchisee undertakes the capital investment necessary to maintain the quality and reliability of power and to meet the expected growth in demand in the franchisee area on a proactive basis.
- The franchisee is responsible for meeting AT&C loss reduction targets; there could be incentives and penalties built into the distribution franchisee agreement (DFA) with respect to achievement of set target levels. The faster the loss reduction targets are met, the earlier the franchisee can capture the surplus of revenues collected over and above the fixed amount to be paid for the energy input. There is accordingly an incentive for the franchisee to expedite loss reduction investments and capture the maximum surplus revenues.

- The franchisee undertakes O&M of the assets being taken over, although these assets continue to be owned by the distribution licensee.
- The franchisee undertakes all customer-related activities such as metering, billing, collection, disconnections and reconnections, and complaint management.
- The franchisee may arrange for procurement of additional power to supply the consumers in its area (over and above what it is receiving from the utility) and recover revenues for this through reliability charges to customers who require the extra power, in accordance with conditions in the DFA and after due approval from the appropriate regulatory commission.

The franchisee is allowed to retain the entire revenue collected from consumers in its area, after it has paid the utility for the input energy at the competitively determined price. Such revenues for the franchisee may include the following:

- Revenue includes amounts billed to consumers against sale of power (billed at the same regulator-approved tariff that would have applied to the licensee).
- Miscellaneous charges include meter rent charges, connection and disconnection charges, fuse-off charges, call attendance charges, and so on.
- There could also be a pass-through of the government subsidy provided for retail tariffs, if applicable (for example, if the government provides subsidies to the utility for serving certain customer categories). However, this aspect has been treated differently in franchisee models across states.
- Incentives on collection of arrears that are still pending from late payments incurred during the prefranchise period, when power was supplied by the licensee, are included. A part, or all, of the amount collected may be retained by the franchisee depending on the conditions of the DFA.
- The franchisee is compensated for the residual or depreciated value of the assets it has financed, at the end of the franchisee period when such assets are transferred to the licensee.
- Electricity duty collected by the franchisee is to be passed on to the licensee, which in turn passes this duty on to the government body entitled to it. This approach may vary from one state to another.

The yearly tariffs for energy input prices quoted by the selected DF at the time of bidding are duly indexed for any future tariff change because of tariff approvals by the respective state electricity regulatory commission (SERC) or change in consumer mix to ensure that the effect of the change is appropriately shared between the licensee and the franchisee. The formula to calculate the indexed input rate for any particular month is arrived at by multiplying the quoted rate for the year by the actual average tariff for the month and dividing it by the opening or base average tariff. Such an average tariff is also often called the average billing rate, and the practice differs across states.

The responsibilities of the licensee normally include making available the guaranteed quantum of power to the franchisee's area and providing authorization or assistance (clearances and approvals from local agencies) to the franchisee

as necessary for undertaking the activities entrusted to it. Such responsibilities depend on the DFA conditions.

The competitive bidding process—with the selection of the bidder who quotes the highest rate for energy input into the electrically ring-fenced area for every year of the contract period—ensures that only bidders with the most aggressive or sharpest loss reduction trajectories emerge as successful. This approach passes on a significant portion of the benefits that may be achieved to the distribution licensee.

The key benefits that may be reaped by the distribution licensees through franchising out appropriate areas to highly motivated and qualified private parties include the following:

- The licensee receives assured revenues at the quoted input rate into the franchisee area for the entire period.
- There are efficiency improvement initiatives and assured reduction of AT&C losses in the franchisee area by the franchisee, who is highly incentivized to make up-front investments in loss reduction in order to maintain his profitability.
- The utility avoids the cost of capital expenditure in the franchisee's area that is undertaken by the franchisee for the period of the DFA.
- The utility avoids O&M expenses in the franchisee's area, and such resources can be deployed in other areas to achieve better efficiency levels.
- The utility is able to recover the outstanding past arrears for its period of supply by offering an incentive to the franchisee, or the utility may sell its claims outright to the franchisee at the time of handing over.

Box 4.1 summarizes the views of two expert panels on the way forward with distribution franchising. Planning Commission member B. K. Chaturvedi headed a subgroup to proceed with the public-private partnership (PPP) model that would enable limited recourse financing by financial institutions and viability gap funding support from the union government to mobilize the requisite volumes of investment. The Shunglu Committee favored the distribution franchising (DF) approach where the private party tasked with lowering AT&C losses would be selected based on a competitive bid price for input energy to be purchased from the discom. The PPP model would provide the requisite flexibility to the concessionaire to procure bulk power from the market at competitive prices. The PPP in distribution subgroup has recommended a 25-year concession period (possibly extended by another 10 years), separate tariffs for regulated and open-access consumers, and a billing and payment mechanism, besides a predetermined system of incentives and penalties on the key performance indicators, to ensure quality and reliability of supply by the concessionaire. According to the subgroup, neither privatization (the Delhi model) nor the distribution franchisee model would deliver the desired outcome. Instead, a well-formulated PPP model could be the way forward. Moreover, the model would be consistent with the Electricity Act of 2003, which requires distribution to be a licensed business under the regulatory

Box 4.1 Shunglu Committee versus B. K. Chaturvedi Report

A task force was set up by the Planning Commission to examine and evolve the framework for the distribution franchisee (DF) and public-private partnership (PPP) models. The Chaturvedi panel favored the PPP model over the DF model or privatization model of Delhi for private participation in the power distribution sector (Planning Commission 2011, paras. 2.2 and 2.3). The Chaturvedi panel pointed out the following:

- The DF model is incapable of bringing adequate capital investments.
- The DF model would not ensure quality and quantity of supply, competition, and open access.
- The DF model will not ensure financial stability of the sector.
- The franchisee is not required to obtain a distribution license and is hence outside of the purview of a state electricity regulatory commission (SERC).
- The DF model suffers from legal issues that restrict the purchase of power from the market.

The Chaturvedi panel recommended a PPP model in the distribution of electricity as consistent with the Electricity Act of 2003 and a way forward. The panel suggested that a concessionaire, selected through competitive bidding, would be responsible for maintenance, operation, and upgrading of the distribution network. The panel recommended enough flexibility to the concessionaire to procure bulk power from the market at competitive prices. The panel also observed that the PPP model would enable limited resource funding by financial institutions and viability gap funding support from the government.

The Shunglu Committee, which came out with its report after the Chaturvedi report, contested the Chaturvedi claim and questioned the financial and administrative viability of the PPP model (Shunglu Committee 2011, paras. 3.4.7 and 3.4.8). The Shunglu Committee supported the DF model. The committee found the following:

- The success and the legality of the DF model are proved in Bhiwandi and the Bombay High Court order, respectively.
- Franchisees are accountable to licensees who are, in turn, accountable to the SERCs.
- Torrent Power has completed Rs 1 billion (US\$16.13 million) of capital expenditure (capex) in Bhiwandi every year; hence, the DF is capable of completing capex.
- The PPP model would cause tariff anomalies in the states and reduce the number of participating companies, which would further hinder competitive bidding and necessitate capital support from the government.
- The PPP model would complicate sharing of assets between the government and the private player.

Meanwhile, many states such as Andhra Pradesh, Karnataka, and Maharashtra have objected to the suggestions of the Chaturvedi panel, while citing successful implementation of the DF model in Bhiwandi.

oversight of the SERC for ensuring consumer protection. The concessionaire would be given the exclusive use of the distribution assets, but the ownership of the assets would remain with the government. The nature and extent of the use of distribution assets would be regulated in accordance with the concession agreement and the applicable laws. Thus, the licensee would be responsible only for activities under its control: (a) transmission and distribution (T&D) losses and efficiency in carrying current from substation to consumer and (b) billing and collecting for the energy sold. According to the subgroup, the concession agreement will specify the existing power purchase agreements (PPAs) that will be transferred to the concessionaire for the supply of electricity to the regulated consumers. The concessionaire would also be free to procure additional power by entering into new PPAs or making other arrangements with the approval of the SERC with regard to supplies to the regulated consumers. Further, the tariff to be charged by a distribution licensee from all regulated consumers (including all consumers other than open-access consumers) would consist of the tariff for supply of electricity and a fixed charge reflecting the wheeling or distribution charge. In the case of open-access consumers, the supply tariff would have to be determined bilaterally between the suppliers and the consumers in accordance with Section 49 of the Electricity Act of 2003. However, the wheeling charge for open-access consumers would be at par with the wheeling or distribution charge payable by regulated consumers in accordance with the provisions of the concession agreement. The subgroup has submitted its report to the Planning Commission.

The previous sections have elaborated on the definitions and modalities of DFs in rural and urban settings. What has been the actual experience on the ground? The following sections summarize the short experience so far.

Review of Rural Franchisee Experiences

Several states have implemented rural DFs in connection with RGGVY schemes. However, the extent of involvement of private players is very limited in such arrangements. In addition, most DFs involve routine outsourcing with only certain activities or responsibilities transferred to the franchisee (usually no capital investment because of the weak financial standing of parties who come forward to participate in rural franchises).

More than 37,000 rural franchisees are in operation, covering more than 216,000 villages across 18 states in the country. Information regarding the nature of franchisees and the number of franchisees appointed and the villages covered across states as of March 31, 2012, is summarized in table 4.4.

The data show that most of the rural franchises are collection franchises in which the franchisee either takes a portion or percentage of the revenue collections achieved or earns an incentive amounting to a predetermined collection efficiency target, depending on the contract. These collection franchisee contracts are usually annual contracts with flexibility to grant extensions.

In addition to the collection franchises, there is also a group of input-based franchises in which the franchisee purchases the energy that is input into its area,

Table 4.4 Nature of Franchisees and Number of Franchisees Appointed and Villages Covered across 18 States as of March 31, 2012

<i>State</i>	<i>Nature of contract</i>	<i>Number of franchisees</i>	<i>Number of villages covered</i>
Andhra Pradesh	Revenue collection	3,647	7,442
Assam	Input-based	978	3,914
Bihar	Input-based	19	723
Chhattisgarh	Revenue collection	40	6,743
Gujarat	Revenue collection	16,658	17,985
Haryana	Revenue collection	18	5,290
Himachal Pradesh	Revenue collection	102	7,554
Karnataka	Revenue collection	12,261	24,310
Madhya Pradesh	Revenue collection	411	654
Maharashtra	Revenue collection	1,346	40,292
Meghalaya	Revenue collection	9	66
Nagaland	Input-based	610	683
Orissa	Revenue collection	48	17,165
Rajasthan	Revenue collection	66	31,742
Tripura	Revenue collection	69	787
Uttar Pradesh	Revenue collection	665	27,388
Uttarakhand	Revenue collection	22	10,514
West Bengal	Revenue collection	645	12,803
Total		37,614	216,055

Source: Ministry of Power, Government of India.

and then resells that energy to consumers (similar to the input-based model used for some urban distribution franchises). In total, 1,607 of the 37,614 rural franchisees are input-based.

The most notable and tested version for the rural input-based approach is the single-point power supply (SPPS) scheme that is referred to in the Rural Electrification Policy of 2005. The SPPS franchisees have traditionally been appointed on a first-come, first-served basis (rather than the competitively selected urban input-based franchisees who must bid for the price that will be paid to the utility for the power supplied). The rural SPPS franchisee sells power to consumers at tariffs approved by the regulator and pays a fixed fee to the distribution licensee. This fee is worked out by the licensee—10 percent of low-voltage line losses, a commission or profit of 15 percent for the franchisee, and a low-voltage line maintenance allowance of 2 percent. Additionally, the licensee offers the franchisee an incentive of 2 percent on timely payment of its bills and a cash incentive (Rs 100 [US\$1.60]) per new connection issued through the franchisee. The difference in treatment for urban and rural franchisees is quite clearly based on the number of likely interested private parties in each case, and this number is, in turn, a function of how potentially lucrative the business prospects are in rural areas versus urban areas.

Rural franchise models have been helpful to the distribution licensees in many states in substantially improving the revenue collections achieved from the rural

areas that were traditionally ignored by the licensees. Therefore, in view of the significant increase in rural electrification being achieved under the RGGVY projects across the country, it has become imperative for licensees to increase their revenue collection focus in rural areas.

Although the input-based franchisee has definite advantages over the collection franchisee, finding entities or agencies with the required skill sets has proved to be a challenge, even before the program has been undertaken on a large scale. Therefore, it is often beneficial for the licensees to initially start with revenue collection-based franchisees and then move on to upgrading these businesses into an input-based franchisee system within a predetermined time frame once the franchisee develops or acquires the requisite skill sets. Training programs introduced by the Rural Electrification Corporation through the Central Institute for Rural Electrification could be leveraged for achieving this at a faster pace.

Review of Urban Franchisee Experiences

Encouraged by the experience of Bhiwandi, a handful of attempts have been made to introduce DFs for identified circles or areas in the states of Bihar, Madhya Pradesh, Maharashtra, and Uttar Pradesh. See table 4.5 for an expanded list.

In addition to the successfully concluded initiatives, table 4.5 shows that there have also been several cases of failures in which the bidding process could not

Table 4.5 DFs for Identified Circles or Areas

<i>Area</i>	<i>Area profile</i>	<i>Bidders</i>	<i>Successful bidder</i>
Bhiwandi, Maharashtra	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 2,420 MU • Consumers: 174,000 • Revenue: Rs 3.5 billion 	Torrent Power Ltd., Crompton Greaves Ltd. (2 total)	Torrent Power Ltd. (operational since January 26, 2007)
Agra, Uttar Pradesh	<ul style="list-style-type: none"> • Tenure: 20 years • Input: 1,799 MU • Consumers: 271,000 • Revenue: Rs 3.47 billion 	Torrent Power Ltd., Reliance Infrastructure Ltd., JUSCO (3 total)	Torrent Power Ltd. (operational since 1 April 2010)
Kanpur, Uttar Pradesh	<ul style="list-style-type: none"> • Tenure: 20 years • Input: 2,664 MU • Consumers: 489,000 • Revenue: Rs 6.45 billion 	Torrent Power Ltd., JUSCO (2 total)	Torrent Power Ltd. (hand-over process under way)
Nagpur, Maharashtra	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 1,090 MU • Consumers: 347,000 • Revenue: Rs 3.37 billion 	Indu Project, GTL Ltd., Crompton Greaves Ltd., SMS Infrastructure Ltd., Reliance Infrastructure Ltd., CESC, Tata Power Company Ltd., Spanco Ltd., A2Z Private Ltd., Vijai Electricals Ltd., Indiabulls Financial Services (11 total)	Spanco Ltd. (DFA executed between MSEDCL and Spanco Ltd. on February 23 2011; Spanco Ltd. started operation in May 2011)
Aurangabad, Maharashtra	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 1,276 MU • Consumers: 205,000 • Revenue: Rs 4.21 billion 	Indu Project, GTL Ltd., A2Z Private Ltd., Ashoka Buildcon Ltd., Spanco Ltd., Indiabulls Financial Services (6 total)	GTL Ltd. (LOI issued)

table continues next page

Table 4.5 DFs for Identified Circles or Areas (continued)

<i>Area</i>	<i>Area profile</i>	<i>Bidders</i>	<i>Successful bidder</i>
Jalgaon, Maharashtra	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 667 MU • Consumers: 115,000 • Revenue: Rs 2.03 billion 	Lanco Infratech Ltd., A2Z Private Ltd., Essar Power, SMS Infrastructure Ltd., Crompton Greaves Ltd., Konark Power, GMR Group (7 total)	Crompton Greaves Ltd. H1 (DFA executed between MSEDCCL and Crompton Greaves Ltd. on June 1, 2011)
Gwalior, CZ-Bhopal, Madhya Pradesh	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 1,031 MU • Consumers: 184,000 • Revenue: Rs 3.32 billion 	Dainik Bhaskar Power, Montecarlo Construction Ltd., Spanco Ltd., A2Z Private Ltd., Essel Group, Torrent Power Ltd., DPSC Ltd., CESC, PNC Infratech Ltd. (9 total)	Smart Wireless (Essel Group) emerged as H1
Ujjain, WZ-Indore, Madhya Pradesh	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 389 MU • Consumers: 95,000 • Revenue: Rs 1.30 billion 	Dainik Bhaskar Power, Montecarlo Construction Ltd., Spanco Ltd., A2Z Private Ltd., Essel Group, CESC, GTL Ltd., Shyam Industries Ltd., ACME Group, PNC Infratech Ltd. (10 total)	Smart Wireless (Essel Group) has emerged as H1.
Sagar, EZ-Jabalpur, Madhya Pradesh	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 163 MU • Consumers: 55,000 • Revenue: Rs 0.55 billion 	Dainik Bhaskar Power, Montecarlo Construction Ltd., Spanco Ltd., A2Z Private Ltd., Essel Group, ACME Group (6 total)	Smart Wireless (Essel Group) emerged as H1
Bhilai Steel Plant Township, Chhattisgarh	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 206 MU • Consumers: 34,029 • Revenue: Rs 0.41 billion 	Due 20 March 2012	Bid process aborted/n.a.
Bokaro Steel City Township, Jharkhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 257 MU • Consumers: 38,792 • Revenue: Rs 0.21 billion 	Due March 20, 2012	Bid process aborted/n.a.
Rourkela Steel Plant Township, Orissa	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 173.32 MU • Consumers: 27,974 • Revenue: Rs 0.15 billion 	Due March 20, 2012	Bid process aborted/n.a.
Durgapur & IISCO Steel Plant Township, West Bengal	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 33.7 MU • Consumers: 19,097 • Revenue: Rs 0.0355 billion 	Due March 20, 2012	Bid process aborted/n.a.
Sheel-Mumbra- Kalwa, Maharashtra	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 409 MU • Consumers: 145,000 • Revenue: Rs 1.11 billion 	Process aborted	n.a.
Roorkee, Uttarakhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 104 MU • Consumers: 27,989 • Revenue: Rs 0.19 billion 	Process aborted	n.a.
Rudrapur, Uttarakhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 66 MU • Consumers: 17,865 • Revenue: Rs 0.12 billion 	Process aborted	n.a.

table continues next page

Table 4.5 DFs for Identified Circles or Areas (continued)

Area	Area profile	Bidders	Successful bidder
Patna, Bihar	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 2,082 MU • Consumers: 374,000 • Revenue: Rs 4.86 billion • AT&C loss: 43.4% 	<ul style="list-style-type: none"> • EOs submitted by 14 bidders • Only Essar Power submitted bid 	<ul style="list-style-type: none"> • Not available • In first round, consortium issue with Glodyne Technoserve Ltd. led to cancellation of process. • In second round, no LOI was placed because only one bid was submitted.
Muzaffarpur, Bihar	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 187 MU • Consumers: 59,000 • Revenue: Rs 0.35 billion • AT&C loss: 53.4% 	Process aborted twice	n.a.
Gaya, Bihar	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 129 MU • Consumers: 57,000 • Revenue: Rs 0.27 billion • AT&C loss: 43.4% 	Process aborted twice	n.a.
Bhagalpur, Bihar	<ul style="list-style-type: none"> • Tenure: 10 years • Input: 176 MU • Consumers: 54,000 • Revenue: Rs 0.32 billion • AT&C Loss: 59.5% 	Process aborted twice	n.a.
Janjgir-Champa, Chhattisgarh	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 880 MU • Consumers: 234,000 • Revenue: Rs 0.85 billion • AT&C Loss: 67.39% 	Process aborted twice	n.a. Urban area was twinned with rural area that attracted few serious big players. In the initial bid, no firm could qualify technically.)

Source: Deloitte research.

Note: AT&C = aggregate technical and commercial; CESC = Calcutta Electric Supply Corporation; CZ = Central Zone; DFA = distribution franchisee agreement; EOI = expression of interest; EZ = Eastern Zone; H1 = highest bidder; JUSCO = Jamshedpur Utilities and Services Company; LOI = letter of intent; MSEDCL = Maharashtra State Electricity Distribution Company Ltd.; MU = million units (million kilowatt-hours); WZ = Western Zone; n.a. = not applicable.

be completed. This included the two rounds of bidding originally held by Bihar State Electricity Board (BSEB) for Patna, Muzaffarpur, Gaya, and Bhagalpur Circles and by Maharashtra State Electricity Distribution Company Ltd. (MSEDCL) for Nagpur (first round in 2007) and Sheel-Mumbra-Kalwa, and so forth.

Lessons Learned for Improvement of the DF Approach: What Are the Key Variables That Must Be Properly Understood and Addressed in the Bid Process?

Important common factors that led to success or failure of the various initiatives for appointing DFs have been analyzed to identify lessons learned for future cases. They are discussed below.

Area Selection for Urban DFs

The urban DF model is structured in such a manner that the successful bid should be the one that offers maximum efficiency improvement (whether it is loss reduction or cost optimization, and so forth). The model ensures, in effect, that the front-loaded capital expenditure required during the initial years (to improve efficiency levels and to improve on the reliability and quality of supply) is fully recovered from the incremental revenues generated by the DF. These incremental revenues arise from the steep reduction of inefficiencies and improved collection performance. At the same time, none of this burden for increased up-front investments is passed on to the licensee. The franchisee's business lives or dies by its ability to be efficient and thereby to recover from the customer base what it has invested in upgrading the network to improve the service, reduce losses, and increase customer satisfaction. However, the franchisee is allowed to charge the customers only the published tariff rates that the customers were being charged previously by the state utility. Therefore, the franchisee must focus on drastically reducing losses and improving collections to recover the input energy price as well as its capital investment in upgrading the network in its area.

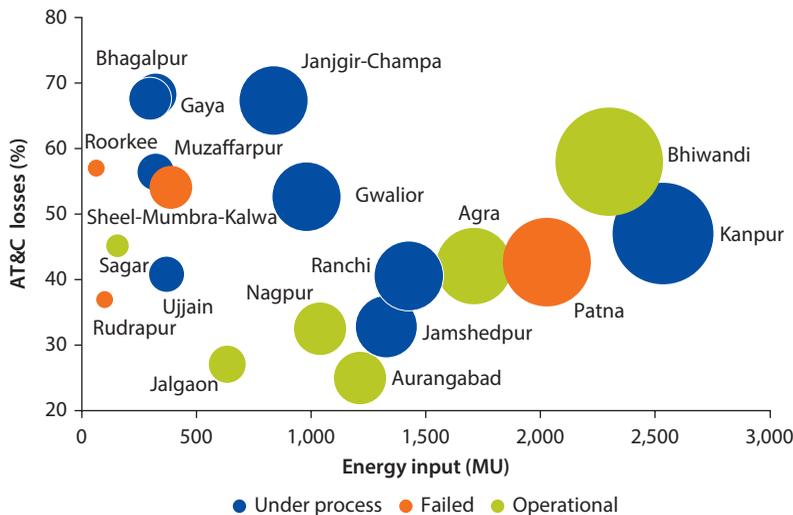
In view of the above, it is essential for the utility to carefully identify potential areas for implementing DF models. Lessons learned seem to point to the following characteristics that make a given area a viable and attractive proposition for the prospective bidders:

- Size of the area in terms of energy input and network infrastructure
- Good and independently viable customer mix in terms of high consumption–high tariff consumers and the growth potential of the area
- Limited geographical spread so that the area is manageable
- Substantial (very high) AT&C losses or inefficiencies that the licensee has not been able to improve in the past years, but with which the private party can do much better (high loss-making areas offer better opportunities [win-win] for both the licensee and the franchisee)

As can be seen from the analysis in figure 4.4 on attractiveness of the franchisee areas bid out so far by various state utilities, the most successful areas have been mainly the sizeable areas with an input of around 500 million units (MU, or million kilowatt hours) and above and with high loss levels.

The areas with low energy input (falling toward the left-hand side of figure 4.4) have largely been seen as unattractive by prospective bidders, and the process for most of such areas has been aborted by the respective distribution utilities. With the utilities developing strict qualification criteria for attracting credible private sector players as prospective franchisees, the utilities have often been unable to attract enough participants for such areas.

In the case of the franchises offered by Madhya Pradesh utilities for Gwalior, Ujjain, and Sagar, the areas for all three circles included a mix of rural and urban

Figure 4.4 Franchisee Area Attractiveness Analysis

Source: Deloitte research.

Note: AT&C = aggregate technical and commercial; MU = million units (million kilowatt-hours). Size of bubble indicates quantum of losses (MU).

areas in the initial versions issued in April 2011. These areas were finally changed to only urban areas after receiving feedback from prospective bidders, during the prebid conferences, that they were not interested in also taking on rural areas.

Patna is a unique case. Despite being one of the most attractive areas put on offer so far, Patna's original franchise could not be awarded to any successful bidder because of other technical reasons in the bidding process. In the first round of bids invited in 2009, Glodyne Technoserve Ltd. emerged as the successful bidder. However, as a result of issues arising in the consortium arrangement through which it had qualified, the process had to be called off. In the second round, the BSEB had set the reserve price for the bids at an extremely high level, making it a very high-risk proposition for most bidders. Ultimately, only a single bid was received, that from Essar Power. Because of the single bidder and, therefore, the lack of competition, the process had to be aborted by BSEB.

Key Terms of DFAs

Although most utilities have by and large followed the Bhiwandi contractual model, certain variations in the approaches have been adopted for different areas by different utilities. These variations have been evaluated and analyzed with respect to their effect on the viability or efficacy of the DF model.

Tenure or Length of the DFA

The term of the contract becomes critical in view of the extent of the franchisee's responsibilities for making capital investments in the urban input-based

franchisee model. A tenure of at least 15 years or longer is desirable for the following reasons:

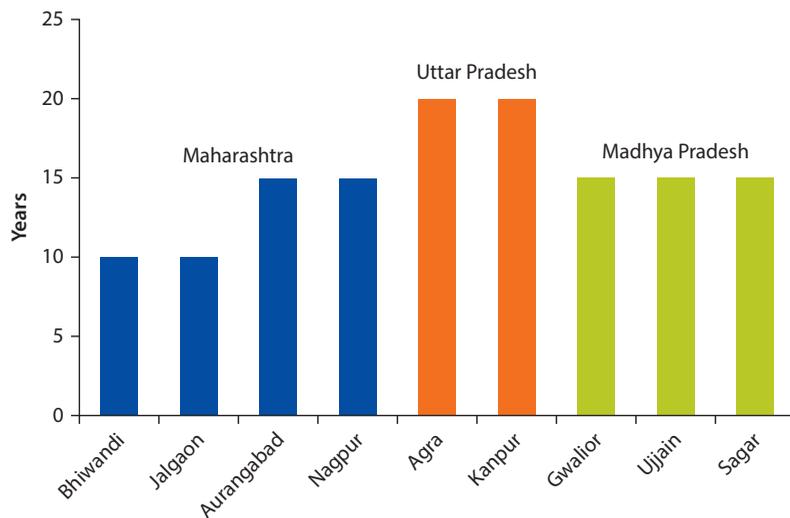
- Investments required in the T&D network in the franchisee area would yield results only several years after their commissioning; the franchisee must have enough time to recover the costs of the investment.
- The quantum of capital investments usually is lop-sided during the first five years, because of the loss reduction and reliability improvement interventions necessary for achieving the targeted loss reduction and consumer service levels. Therefore, a longer-term DFA will ensure that a significant portion of the assets put in place by the DF is suitably depreciated by the end of the term. If not, the utility will be paying a high residual value to the franchisee at the end of the contract.
- Several technical loss reduction initiatives such as underground cabling, gas-insulated switchgears, and high voltage distribution systems have longer pay-back periods. If the tenure of the DFA is too short, the franchisee will have no incentive to undertake such initiatives in the franchisee area.

Maharashtra has adopted tenures of 10 years for Bhiwandi and Jalgaon and 15 years for Aurangabad and Nagpur. Uttar Pradesh has adopted a tenure of 20 years for the Agra and Kanpur DFs, and Madhya Pradesh has adopted a tenure of 15 years for the ongoing bids for Gwalior, Ujjain, and Sagar (figure 4.5).

Performance Targets Set for DFs

Although the competitive bidding mechanism for appointment of the DF ensures to a large extent that the intended efficiency benefits are achieved and

Figure 4.5 Tenure of DFs



Source: Deloitte research.

Note: DF = distribution franchisee.

passed on to the licensee, the licensees have started to put additional clauses into the DFAs, giving specific targets to the DFs for the following parameters (this type of micro-management by the utility has also allegedly dampened the enthusiasm of participants to later bidding rounds for DFs):

- AT&C losses and collection efficiency targets, or both, for the franchise period (though some utilities have given targets in a flexible manner to be achieved over a period of time, others have specified annual loss reduction targets)
- Minimum capital investment specified during the first few years or during the entire franchise period
- Metering levels to be achieved, in view of any targets drawn from the directives given to the distribution licensee by the respective regulatory commission
- Creation of call centers and complaint management systems to monitor the compliance levels against standards of performance mandated by the respective regulatory commission and to improve the customer service levels in general

The targets given in the DFAs in some of the recent bids are summarized in table 4.6.

Table 4.6 Summary of Targets of the Recent Bids

<i>Distribution franchisee</i>	<i>Loss reduction</i>	<i>Capital expenditure</i>	<i>Metering</i>	<i>Collection efficiency</i>	<i>Customer satisfaction</i>
Bhiwandi	No target specified	Not specified	Not specified	Not specified	Not specified
Agra	15 percent AT&C losses within five years	Capex target as per infrastructure roll-out plan	Not specified	Not specified	Not specified
Nagpur	Loss level of 10.02 percent at end of 15 years	Capex target as per infrastructure rollout plan	Not specified	Achieve 99.50 percent collection efficiency every year	Not specified
Kanpur	AT&C loss level of 20 percent within five years	Capex target as per infrastructure rollout plan	Not specified	Not specified	Not specified
Aurangabad	Loss level of 3.85 percent at end of 15 years	Not specified	Not specified	Not specified	Not specified
Jalgaon	Loss level of 15 percent within five years of operations	Capex target as per infrastructure rollout plan	Not specified	Not specified	Not specified
Gwalior	Loss level of 15 percent until December 2013, maintained until December 2018; reduction of 1 percent every year thereafter until it reaches 10 percent	Mandatory capex target	100 percent metering within two years	100 percent	Round-the-clock operationalized call center within 30 days before end of transition period

table continues next page

Table 4.6 Summary of Targets of the Recent Bids (continued)

<i>Distribution franchisee</i>	<i>Loss reduction</i>	<i>Capital expenditure</i>	<i>Metering</i>	<i>Collection efficiency</i>	<i>Customer satisfaction</i>
Ujjain	Loss level of 15 percent until December 2013 and maintained until December 2018; reduction of 1 percent every year thereafter until it reaches 10 percent	Mandatory capex target	100 percent metering within two years	100 percent	Round-the-clock operationalized call center within 30 days before end of transition period
Sagar	Loss level of 15 percent until December 2013 and maintained until December 2018; reduction of 1 percent every year thereafter until it reaches 10 percent	Mandatory capex target	100 percent metering within two years	100 percent	Round-the-clock operationalized call center in 30 days before end of transition period

Source: Deloitte research.

Note: AT&C = aggregate technical and commercial; capex = capital expenditure.

As can be seen in table 4.6, the licensees have realized the potential benefits that can be achieved through the private sector interventions in the loss-making distribution areas. Therefore, they have been giving increasingly difficult targets to prospective franchisees in the recent bids.

It is also standard practice to introduce regulatory approvals on the franchisee's proposed capital expenditure toward the end of the franchisee period. Such assets would be transferred to the licensee at depreciated values and could lead to a sharp tariff increase (based on a spike in the assets that form the rate base) at the end of the franchisee period.

Most licensees have not included contractual clauses in the DFAs specifically dealing with collection efficiency because collection efficiency is considered to be implicit in the AT&C loss levels and it is in the financial interest of the DF itself to collect the entire amount billed. However, some utilities have mandated 100 percent collection efficiency during all years of the franchisee period, especially in the case of the recent Madhya Pradesh DF bids.

The DF bids in Madhya Pradesh are also unique in terms of their focus on establishing systems for measurement of compliance to the Standard of Performance Regulations implemented by the Madhya Pradesh Electricity Regulatory Commission. Also, the DFA mandates the DF to set up a round-the-clock call center within 30 days of taking over, for recording and monitoring of technical and commercial complaints received from consumers.

Penalties are specified also in some of the DFAs for nonachievement of the set targets. In the cases of Agra and Kanpur DFAs, if the DF fails to meet the loss reduction targets, a penalty amounting to 10 percent of the revenue loss to the licensee is imposed on the DF (for each year of the contract). In the cases of Gwalior, Ujjain, and Sagar, there is a yearly penalty for any loss of revenue to the utilities, which varies from 1 percent to 5 percent from year to year.

Treatment of Subsidy and Collection against Arrears

The treatment of subsidies arising out of the sale of power by the DF to customer categories in which tariff subsidies are provided or approved by the state government, especially in the agricultural and the below-poverty-line customer categories, has varied across states. It is important to note that the treatment of subsidies (that is, whether the subsidy is to be retained by the licensee or to be passed on the franchisee) may significantly affect the viability of the franchisee model, especially if the consumer mix is skewed toward the categories that attract subsidies.

Another important parameter that may significantly affect the viability of the franchisee is the incentive that is allowed on the collection of arrears that are owed to the licensee from service provided during the prefranchise period. The details are provided in table 4.7.

The DFAs for Bhiwandi, Nagpur, Aurangabad, and Jalgaon by the MSEDCL allowed for pass-through of subsidies to the DFs. However, bids invited by other states such as Uttar Pradesh and Madhya Pradesh have allowed for subsidies to be retained by the licensees.

Different levels of incentives have been provided to the franchisees for arrears pertaining to connected and disconnected consumers. Although almost all utilities have allowed the DFs an incentive of 10 percent on connected consumers' arrears, the incentive for collection of arrears pertaining to disconnected consumers has varied between 20 percent and 25 percent across different DF bids.

The DF bids recently invited in the state of Madhya Pradesh for Gwalior, Ujjain, and Sagar are unique in the treatment of arrears, because the entire

Table 4.7 Incentive on the Collection of Arrears on Service Provided during the Prefranchise Period

<i>DF bid</i>	<i>Treatment of subsidy</i>	<i>Treatment of collection against arrears</i>
Bhiwandi	Claim against subsidy would be remitted to DF.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 20 percent incentive on collection from disconnected consumers
Agra	DVVNL would retain the subsidy.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 20 percent incentive on collection from disconnected consumers
Nagpur	Claim against subsidy would be remitted to DF.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 25 percent incentive on collection from disconnected consumers
Kanpur	KESCO would retain the subsidy.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 20 percent incentive on collection from disconnected consumers
Aurangabad	Claim against subsidy would be remitted to DF.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 25 percent incentive on collection from disconnected consumers
Jalgaon	Claim against subsidy would be remitted to DF.	<ul style="list-style-type: none"> • 10 percent incentive on collection from connected consumers • 25 percent incentive on collection from disconnected consumers
Gwalior	Licensee would retain the subsidy.	<ul style="list-style-type: none"> • Franchisee could keep all arrears against connected and disconnected consumers collected after effective date of operation.
Ujjain	Licensee would retain the subsidy.	<ul style="list-style-type: none"> • Franchisee could keep all arrears against connected and disconnected consumers collected after effective date of operation.
Sagar	Licensee would retain the subsidy.	<ul style="list-style-type: none"> • Franchisee could keep all arrears against connected and disconnected consumers collected after effective date of operation.

Source: Deloitte research.

Note: DF = distribution franchisee; DVVNL = Dakshinanchal Vidyut Vitran Nigam Ltd.; KESCO = Kanpur Electricity Supply Company Ltd.

outstanding arrears are considered sold to the DFs. It may also be noted that, in the absence of consistent and reliable data being made available to all prospective bidders to accompany arrears clauses, the bidding process becomes speculative and subjective (that is, the franchisees will acquire all past claims of the licensees, but this is not helpful unless the amount is also credibly specified).

Treatment of Additional Power Purchase by DFs

Although all DFAs have allowed for additional power purchases by DFs in the event of shortfall in the supply being made available by the licensee, subject to regulatory approvals, the mechanism for recovery of costs for these purchases from the ultimate consumers is not addressed. This omission leaves scope for regulatory uncertainty and assumptions by the bidder that may lead to future disputes.

However, the recently invited DF bids in the state of Madhya Pradesh for Gwalior, Ujjain, and Sagar suggest that recovery of expenses may be sought on such additional power purchases. Recovery may come through reliability charges that may be approved by the Madhya Pradesh Electricity Regulatory Commission.

Review of the Process for Appointment of DFs

The process in which the appointment of urban DFs is conducted is critical to the utilities' ability to build confidence among prospective investors or bidders. It also affects the ability of a utility to appoint a suitable partner, keeping in mind the long-term interests of all stakeholders including, most important, its consumers.

As mentioned previously, the process of appointing a DF is much more critical than the standard generation and transmission bidding processes whereby bids are generally invited for new-build assets by prospective investors. In a DFA, existing customers of the licensee are handed over to the appointed DF. A single-stage process has been followed in the DF bids invited in the past, with a single request for proposal (RFP) stage similar to the bidding process being followed for case 1 bids in generation.

Quality and Extent of Baseline Data

Once a suitable area is identified, based on the potential benefits that may be achieved and the attractiveness of the area to potential bidders, the licensee needs to undertake preparation of the baseline data that will be made available to the potential bidders in the RFP or the data room, or both. The availability of credible baseline data on the parameters provided in table 4.8 is essential, as has been seen in past bids.

The quality of baseline data is essential not only for the potential bidders, but also for the licensee in deciding on trajectories of key performance indicators (such as distribution losses, collection efficiency, and investment requirements) to set appropriate targets for the franchisee. Without reliable baseline data, the licensee will be unable to monitor progress by the franchisee.

Table 4.8 Quality and Extent of Baseline Data

<i>Key aspects</i>	<i>Specific data points</i>	<i>Remarks and observations</i>
Billing and recovery-related information	<p>The following historical information is required for the previous three- to five-year period:</p> <ul style="list-style-type: none"> • Number of consumers and connected load, by customer category • Units billed, by customer category • Breakup of metered and un-metered sales for each category • Amount billed, by customer category, with a breakdown into tariff components, subsidy, duties and cess (tax), surcharges, and so forth • Collection and recovery, by customer category • Aging analysis of connected and disconnected arrears, by customer category • Status of consumer metering, by customer category, with details of the population with various types of meters, aging of meters, specifications of meters, number of working or faulty meters 	<p>To ensure availability of such information, the following shall be a prerequisite:</p> <ul style="list-style-type: none"> • An IT-based billing system is implemented that contains complete repository of the billing history of consumers in the selected area. • Consumers for the proposed DF area are identifiable or marked in the billing system, so that appropriate reports and data can be extracted and made available to the prospective bidders.
Energy input	<p>The following historical information is required for the preceding three- to five-year period:</p> <ul style="list-style-type: none"> • Energy input at the 33-kV level • The loading pattern, voltage characteristics, and so forth • Preferably, feeder-level information (as done in certain states) 	<p>To ensure availability of such information, the following shall be a prerequisite:</p> <ul style="list-style-type: none"> • The proposed area must be demarcated in terms of its energy input points at the 33-kV level. • In case there are any crossovers at lower voltages, these may either be done away with or be appropriately metered and recorded. • Meter readings and other details must be recorded on a daily basis in either a manual logbook or software-based logs, so they can be verified by the prospective bidders.
Network infrastructure information	<p>The following historical information is required for the preceding three- to five-year period:</p> <ul style="list-style-type: none"> • Subtransmission lines in circuit kilometers at 33-kV level and 11-kV level • Low-voltage lines, in circuit kilometers, along with number of poles and so forth • Numbers and ratings of power transformers of 33- and 11-kV • Status of metering at 33- and 11-kV substation levels • Numbers and ratings of distribution transformers of 11 kV and 415 V • Status of metering at distribution transformer level • Power transformer failure rate • Distribution transformer failure rate 	<p>If the licensee does not maintain appropriate records, it will need to undertake a field asset survey to provide the listed information to the prospective bidders on the as-is network infrastructure in the proposed DF area.</p>
Ongoing Contracts or works	<p>The licensee needs to make available information on the following:</p> <ul style="list-style-type: none"> • Ongoing or tied-up capital works being undertaken by the licensee that may be commissioned or may spill over to the franchisee period • Various O&M contracts entered into by the licensee that may or may not be continued by the franchisee 	<p>A summary of such contracts or works may be provided in the RFP (for example, R-APDRP works that were mentioned in the recently invited Madhya Pradesh DF bids) and copies of the underlying contracts made available to the prospective bidders on request.</p>

Source: Based on study.

Note: DF = distribution franchisee; kV = kilovolt; O&M = operation and maintenance; RFP = request for proposal; R-APDRP = Restructured Accelerated Power Development and Reforms Programme; V = volt.

In addition to the above, the licensee also needs to assess the O&M costs and capital costs that are avoided through the appointment of a franchisee in the selected area. This assessment will allow the licensee to calculate potential savings during the franchisee period.

Qualification Criteria for Prospective Bidders

Although direct experience on the part of the franchisee in undertaking power distribution with a comparable customer base would appear to be the most appropriate technical criterion for prequalifying prospective bidders, such a criterion would seriously limit competition. This is because private sector participation in distribution has been available to only a few players in the legacy utilities in Ahmedabad, Kolkata, Mumbai, and Surat.

Table 4.9 provides the various criteria included in past DF bidding documents. Licensees have attempted to widen the pool of potential bidders by including players who either have experience in undertaking civil works in the distribution business for existing licensees or have direct experience in handling large customer bases in other sectors such as telecoms and so forth.

Opening up the pool of potential bidders, by prequalifying players with experience of handling customer bases in other industries, has resulted in much more aggressive quotations relative to conventional private sector power distribution players who understand the pitfalls of the power distribution business. The DF procurement process has resulted in the emergence of Spanco Ltd. (for Nagpur), GTL Ltd. (for Aurangabad), and Smart Wireless (for Gwalior, Ujjain, and Sagar) as the winning bidders. However, the actual ability of such players to manage power distribution has yet to be demonstrated; Nagpur and Aurangabad have only recently been handed over and the handing-over process for Gwalior, Ujjain, and Sagar has yet to be completed.

Once the actual operational results for Nagpur, Aurangabad, and other such cities are observed for a period of time, it will become clear whether implementing such broad-based qualification requirements to attract new investors has resulted in real benefits for the licensee. The bids invited in the state of Uttar Pradesh largely followed the qualification requirement used by the distribution licensee (MSEDCL) in the state of Maharashtra. However, the licensees in the state of Madhya Pradesh also included parties who were involved in other segments of the power sector, such as generation; transmission; and engineering procurement and construction contracting.

Although bidding through consortia has been allowed in most cases, this approach did not apply to bids for Bhiwandi and Aurangabad that were invited by the MSEDCL in Maharashtra. It may be noted that such consortia are critical only in cases where either the experience requirement is very unique or the size of required investments is very large, both of which are not true for most DF bids. Therefore, once the technical experience requirement has been broadened to include players with experience in any segment in the power sector (for example, generation and transmission as well as distribution) or with handling of customers in other sectors (nonpower), or both, the need for consortium bidding

Table 4.9 Experience Criteria Included in Past DF Bidding Documents

<i>DF bid location</i>	<i>Experience criteria</i>	<i>Consideration for consortiums</i>
Bhiwandi	<ul style="list-style-type: none"> • Experience of handling 200,000 consumers, or • 500 employees for two years and • At least five personnel with power sector experience of more than 10 years 	
Agra	<ul style="list-style-type: none"> • Two years experience in power sector in GTD, or • Experience of handling 200,000 consumers for two years, or • 500 employees for three years and • At least five personnel with power sector experience of more than 15 years 	<ul style="list-style-type: none"> • No more than three companies are allowed, lead partner must have 51 percent equity, and no member may have less than 10 percent equity.
Nagpur	<ul style="list-style-type: none"> • Experience of handling 200,000 consumers, or • 500 employees for two years and • At least five personnel with power sector experience 	<ul style="list-style-type: none"> • No restriction
Kanpur	<ul style="list-style-type: none"> • Two years experience in power sector in GTD, or • Experience of handling 200,000 consumers for two years, or • 500 employees for three years and • At least five personnel with power sector experience of more than 15 years 	<ul style="list-style-type: none"> • No more than three companies are allowed, lead partner must have 51 percent equity, and no member may have less than 10 percent equity.
Aurangabad	<ul style="list-style-type: none"> • Experience of handling 200,000 consumers, or • 500 employees for two years and • At least five personnel with power sector experience of more than 10 years 	<ul style="list-style-type: none"> • Not allowed
Jalgaon	<ul style="list-style-type: none"> • Experience of handling 200,000 consumers for two years, or • 500 employees for two years and • At least five personnel with power sector experience 	<ul style="list-style-type: none"> • No restriction
Gwalior	<ul style="list-style-type: none"> • Experience of owning a power generation project with capacity of 250 MW, holding a power distribution or transmission license, or constructing a generation or transmission facility worth at least Rs 330 billion for a state or central utility, or • Experience of handling 200,000 consumers for two years and • 350 employees for two years 	<ul style="list-style-type: none"> • No more than three companies are allowed, lead partner must have 51 percent equity, and no member may have less than 10 percent equity.
Ujjain	<ul style="list-style-type: none"> • Experience of owning a power generation project with capacity of 250 MW; holding a power distribution, transmission, or trading company; constructing a generation or transmission facility worth at least Rs 100 billion for a state or central utility; or manufacturing a generation, transmission, or distribution equipment worth at least 100 billion, or • Experience of handling 334,000 consumers for two years and • 170 employees for two years 	<ul style="list-style-type: none"> • No more than three companies are allowed, lead partner must have 51 percent equity, and no member may have less than 10 percent equity.
Sagar	<ul style="list-style-type: none"> • Experiencer of owning a power generation project with capacity of 250 MW, holding a power distribution or transmission license, or constructing a generation or transmission facility worth at least Rs 100 billion for a state or central utility, or • Experience of handling 50,000 consumers for two years and • 100 employees for two years 	<ul style="list-style-type: none"> • No more than three companies are allowed, lead partner must have 51 percent equity, and no member may have less than 10 percent equity.

Source: Deloitte research.

Note: GTD = generation, transmission, and distribution; MW = megawatt.

Table 4.10 Summary of Parameters for Financial Qualification Criteria

<i>Franchisee</i>	<i>Financial criteria</i>
Maharashtra—Bhiwandi	<ul style="list-style-type: none"> • Net worth for the past financial year • Annual turnover for the past two financial years • Cash flow from operations for the past two financial years • Listing on a recognized stock exchange
Uttar Pradesh—Agra, Kanpur	<ul style="list-style-type: none"> • Net worth for the past financial year • Annual turnover for the past three financial years • Cash flow from operations for the past three financial years • Listing on a recognized stock exchange
Maharashtra—Nagpur, Aurangabad	<ul style="list-style-type: none"> • Net worth for the past financial year • Annual turnover for the past two financial years • Cash flow from operations for the past two financial years • Listing on a recognized stock exchange
Maharashtra—Jalgaon	<ul style="list-style-type: none"> • Net worth for the past financial year • Annual turnover for the past three financial years • Cash flow from operations for the past three financial years • Listing on a recognized stock exchange
Madhya Pradesh—Gwalior, Ujjain, Sagar	<ul style="list-style-type: none"> • Net worth for the past financial year • Annual turnover for the past two financial years • Positive profit after tax for the past two financial years

is diminished. The risk associated with consortium bidding is the potential for dilution of ownership, commitment, and responsibility as the number of parties increases.

There have also been significant variations in the financial qualification criteria set for prequalification in the various DF bids. In the transactions conducted to date, different criteria have been used, including net worth, turnover, cash flows, profit track records, and so forth, and various combinations thereof. The parameters on which the financial qualification criteria were based in some recent bids are summarized in table 4.10.

There were several modifications or changes made to the technical and financial qualification criteria in certain bids in the past. The perception was that these were tailored to include certain players who were keen to undertake DF business in certain areas.

Time Taken for Concluding the Bid Process

A period of six to eight months, starting from the issue of the first set of RFP and DFA documents up to final handing over of the area to the appointed DF, would be a reasonable time frame for undertaking the various intermediate activities involved. However, for the transactions conducted to date, there have been several procedural delays caused by resistance from employees and other stakeholders and by data-quality issues. These delays in the completion of the bidding process have occurred even in cases where the successful bidder had already been identified and the letter of intent (LOI) issued. Some examples of the time taken for concluding the bid process are provided in table 4.11.

Table 4.11 Time Taken for Concluding the Bid Process

<i>Utility</i>	<i>Franchisee area</i>	<i>Date of issuance of notice of intent to tender</i>	<i>Date of signing of agreement</i>	<i>Date of start of DF operation</i>
DVVNL, Uttar Pradesh	Agra	February 2009	Agreement executed on May 18, 2009, and supplementary agreement on March 17, 2010	April 2010
KESCO, Uttar Pradesh	Kanpur	February 2009	Agreement executed on May 18, 2009	Not yet started
MSEDCL, Maharashtra	Nagpur	January 2010	Agreement executed on February 23, 2011	May 2011
MSEDCL, Maharashtra	Aurangabad	January 2010	Agreement executed on February 23, 2011	May 2011
MSEDCL, Maharashtra	Jalgaon	November 2010	Agreement executed on June 1, 2011	November 2011

Source: Deloitte research.

Note: DF = distribution franchisee; DVVNL = Dakshinanchal Vidyut Vitran Nigam Ltd.; KESCO = Kanpur Electricity Supply Company Ltd.; MSEDCL = Maharashtra State Electricity Distribution Company Ltd.

Although all utilities have normally taken approximately a year and a half to complete the handling of the bid process, certain cases have been delayed much longer. Torrent Power Ltd., despite entering into the DFA for Kanpur in March 2009, had still been unable to take over the franchise, which was later abandoned, primarily because of employee resistance, which had not been resolved by the licensee to date. The Kanpur story demonstrates that the characteristics of the area to be franchised can be as important to the success or failure as the characteristics of the franchisee (in this case, a very capable and experienced company with a demonstrated track record).

Review of Successes and Failures

From a review of past cases, one clearly sees more cases of failure than success in urban input-based distribution franchises. After the success of the Bhiwandi franchise undertaken by Torrent Power Ltd., the Maharashtra utility and utilities in a handful of other states started actively pursuing the idea of implementing the DF model in high loss-making urban areas where they had been unable to reduce losses and improve the quality of supply on their own.

However, the process of appointing DFs has not been an easy experience for the distribution licensees, and several failures have occurred. Despite the fact that more than five years have passed since the demonstrated success of the Bhiwandi model, there are at present still only four operational DFs in the country: Agra, Aurangabad, Jalgaon, and Nagpur⁶ in addition to Bhiwandi.

The aborted or failed bid processes point to the underlying weaknesses, lack of transparency, unbalanced approach, and the unclear rationale of the processes undertaken. Some of the key reasons for abandoned bid processes or failure of completed bid processes are presented in table 4.12.

Table 4.12 Key Reasons for Abandoned Bid Processes or Failure of Completed Bid Processes

<i>DF bid</i>	<i>Reason</i>
Nagpur (round 1) by MSEDCL	<p>MSEDCL, after the success of Bhiwandi, initiated the bid process for appointing a franchisee for the city of Nagpur that had a full-fledged DFA (an improvement over Bhiwandi) and a minimum expected input rate trajectory worked out on the basis of AT&C loss reduction from 39 percent to 12 percent during the 15-year franchise period. The reasons that led to the failure of the bidding process include the following:</p> <ul style="list-style-type: none"> • The input rate quoted by the winning bidder was unrealistic, because after a few years the rates were higher than the average revenue realization. This circumstance suggested that even without consideration of labor, financing charges, administrative expenses, and so forth, the revenue realized from the business would not sustain the quoted input rate to be paid to MSEDCL. The other bids were at least 25–30 percent lower than that of the successful bidder. • Unfortunately, there was no such methodology prescribed in the financial bid evaluation process to highlight and reject such bids; therefore, despite the issue being apparent, MSEDCL went ahead and accepted the bid. • There were also cases in the high court challenging MSEDCL's decision to award franchises for parts of Nagpur city, and because the questions of loss reduction and benefits to MSEDCL were involved, the case was referred to the MERC by the High Court. • Thereafter, the successful bidder pulled back and did not execute the DFA with the MSEDCL.
Patna, Muzaffarpur, Gaya, and Bhagalpur by BSEB	<p>Bihar franchisees, round 1, 2009:</p> <p>BSEB had invited bids for appointment of DFs for Patna, Gaya, Muzaffarpur, and Bhagalpur. One of the conditions was that the bidders for Patna would have to bid for at least one more DF area. Reliance Infrastructure Ltd. had bid for all four areas, CESC for Patna and Muzaffarpur, and Glodyne Technoserve Ltd. for Patna and Gaya. The following issues led to the abandoning of the bid process:</p> <ul style="list-style-type: none"> • Glodyne Technoserve Ltd. had emerged as the highest bidder for Patna. However, because of certain issues identified in the consortium structure, a LOI was not issued by BSEB to Glodyne Technoserve Ltd.; BSEB challenged the admissibility of the Glodyne Technoserve Ltd. bid in the Patna High Court. • Thereafter, BSEB abandoned the bid process. <p>Bihar franchisees, round 2, 2011:</p> <p>BSEB started a fresh bidding process for the appointment of DFs for Patna, Gaya, Muzaffarpur, and Bhagalpur in 2011. Again, one of the conditions was that the bidders for Patna would have to bid for at least one more DF area. The following issues again led to the cancellation or abandonment of the process by BSEB²:</p> <ul style="list-style-type: none"> • BSEB had specified a very high reserve price for input rate. • Only Essar Power submitted its bid. • Essar Power emerged as the single bidder for the DF areas, and BSEB did not issue the LOI. • Essar went to court to get the LOI issued.

table continues next page

Table 4.12 Key Reasons for Abandoned Bid Processes or Failure of Completed Bid Processes (continued)

<i>DF bid</i>	<i>Reason</i>
Rudrapur and Roorkee by UPCL	<p>The NITs for appointment of DFs for Rudrapur and Roorkee cities were issued by UPCL in October 2010. However, the process stalled because of the following issues:</p> <ul style="list-style-type: none"> • A very high reserve price in the bid documents was noted by the potential bidders • Employee resistance occurred.
Dewas and Ujjain by Madhya Pradesh discoms	<p>MPPKVV initiated the process for appointment of DFs for Dewas and Ujjain cities in fiscal year 2006/07. M/s Dainik Bhaskar had emerged as the preferred bidder from the competitive bidding process. Despite the completion of the bidding process, the LOI was never placed on the successful bidder because of the following inconsistencies identified in the DFA:</p> <ul style="list-style-type: none"> • There was no clause for tariff indexation in the input rates quoted by the DF. • No efficiency improvement targets were specified for the interim years of the franchisee period against which the DF could be held liable. • Procedures for adjustment of spillover revenues during the initial transfer and the final transfer-back years were not specified in the DFA. • Clauses regarding discriminatory load shedding and the consequential effect on the DF's revenues were missing in the DFA. • A mechanism for recovery of additional power purchases by DF from external sources was not specified in the DFA. <p>Although the MPPKVV retained the rights to undertake capital works in the franchisee area at its sole discretion, the demarcation between the obligations of the licensee and the franchisee were not addressed in the DFA.</p>

Note: AT&C = aggregate technical and commercial; BSEB = Bihar State Electricity Board; CESC = Calcutta Electric Supply Corporation; DF = distribution franchisee; DFA = distribution franchisee agreement; discom = distribution company; LOI = letter of intent; MERC = Maharashtra Electricity Regulatory Commission; MPPKVV = Madhya Pradesh Paschim Kshetra Vidyut Vitaran Company Ltd.; MSEDCL = Maharashtra State Electricity Distribution Company Ltd.; NIT = notice of intent to tender; UPCL = Uttarakhand Power Corporation Ltd.

a. Another round of a failed bid for Patna occurred in 2013.

Distribution remains the critical weak link in the power sector reform process. There is limited appetite for outright privatization, and therefore, DFs are the most likely way forward. A number of lessons have emerged, as captured above, and these will be used to refine the process going forward. There is no alternative for the sector but to proceed with implementation of all possible instruments to improve efficiency and reduce losses and to improve customer satisfaction.

Appendix G contains a summary of recommendations for the way forward on DF selection, based on lessons learned from successes and failures so far. Appendix H suggests a way for standardizing the approach to future distribution franchising, informed by lessons of successes and failures that have been observed in the past two years.

Notes

1. Uttar Pradesh, Tamil Nadu, Madhya Pradesh, Rajasthan, and Maharashtra together account for more than 60 percent of the total losses without subsidy and 40 percent of total sales of all distribution utilities in India for fiscal year 2009/10.
2. Delhi's distribution companies were the last example of distribution privatization in India, completed in 2002. Since then, only a handful of DFs have been implemented, starting with Bhiwandi in 2007. Appendix F provides a detailed analysis of the privatization approach compared to the distribution franchising approach.
3. In addition to the private licensees mentioned, there are private licensees in the Greater Noida area (Noida Power Company Ltd.), Jamshedpur (Jamshedpur Utilities and Services Company and Tata Steel), and so forth, which are also performing at significantly high efficiency levels in comparison to the state government utilities in the respective states.
4. Three World Bank reports (2003a, 2003b, 2004) provide substantial insights on Orissa and Delhi privatization experiences.
5. Distribution franchisees in Gwalior, Ujjain, and Sagar in Madhya Pradesh; Muzaffarpur, Bhagalpur, and Gaya in Bihar; and Ranchi and Jamshedpur in Jharkhand have also been awarded to respective successful bidders during the past few years.
6. Bhagalpur, Gaya, Muzaffarpur, and Sagar have also been made operational during 2012–14.

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Private Sector Participation in the Indian Solar Energy Sector

Key Messages

- In 2009, the Indian Ministry of New and Renewable Energy (MNRE) announced the National Solar Mission (NSM), a plan to add 20,000 megawatts (MW) of new grid-connected solar generation capacity from the private sector.
- The NSM, which is being implemented in three distinct phases up to 2022, has rapidly added on-grid solar capacity and has attracted widespread private sector interest, with sharp drops in tariffs resulting from reverse auctions.
- The Indian Renewable Energy Development Agency, the financial arm of the MNRE, finances solar photovoltaic (PV) projects; commercial banks have largely stayed away.
- State utilities are subject to renewable purchase obligations (RPOs) and can buy or sell renewable energy certificates (RECs); the RECs are the institutional underpinnings of the market for solar energy.
- The feed-in tariff for grid-connected solar generation started at Rs 17.91/kilowatt-hour (kWh) and has now fallen to Rs 7.49/kWh as a result of price discovery through reverse auctions.
- There is an innovative partnership between the MNRE and the commercial arm of the largest central government-owned thermal power producer—NTPC (National Thermal Power Corporation) Vidyut Vyaparan Nigam Ltd. (NVVN).
- To lower the cost of solar power for financially strapped utilities, NVVN arranges a blended price of thermal power and solar power to make the cost of solar power more affordable.
- States also operate their own grid-connected solar programs, but they are unable to offer the blended thermal price to lower the cost of solar power for their distribution companies (discoms) because this price is available only for capacity procured under the NSM.

This chapter was prepared in 2012 on the basis of discussions and consultations with the Council on Energy, Environment, and Water, with regard to the National Solar Mission. The author particularly wishes to thank Arunabha Ghosh, chief executive officer of the council, for discussions and sharing of background documents.

The NSM document, released by the MNRE in November 2009, sets out the mission's varied targets and objectives and provides guidelines and policy tools to achieve these goals. The targets are bold: NSM seeks to install 20,000 MW of grid-connected solar power by 2022. Qualifying projects, sourced from private sector investors, are selected through a reverse auction procurement mechanism and are ostensibly technology-neutral, employing either solar PV or solar thermal technology.

The mission was launched in January 2010, when the Indian solar energy market size was 17.8 MW. By March 2012, the cumulative capacity had grown to 506.9 MW. Of this capacity, 203.4 MW were commissioned under the NSM and other central government schemes. Another 303.5 MW were deployed under initiatives of various states. Table 5.1 provides NSM targets for 2010–22.

The NSM objectives consist of both specific goals to be accomplished within the phased timeline and broader goals without a definite deadline. Phase 1 focuses on setting up an environment to enable solar technology penetration at centralized and decentralized levels. Phase 1's guidelines explicitly aim to facilitate quick implementation of the NSM, while ensuring serious participation by, and enhanced confidence in, the selected project developers. Promoting private sector manufacturing in India's solar sector is another phase 1 goal.

Phase 2 contemplates an aggressive capacity ramp-up to facilitate competitive solar energy penetration in India. The guidelines envision scaling up through enforcement of a mandatory RPO for utilities, backed by a preferential tariff.

Phase 3, the final phase, aims to meet or exceed the end target of 20,000 MW of grid-connected solar power by 2022. Rapid scaling-up of installation during phase 3 is anticipated through the availability of international finance and technology. The NSM seeks to achieve grid parity by 2022 and parity with coal-based thermal power by 2030.

The success of the mission is contingent on coordination among existing and new institutions. The NSM is overseen by the MNRE. In a good example of public-private partnership, the NRVN enters into 25-year power purchase agreements (PPAs) to procure power from private sector project developers and supplies an allocated amount of MW capacity to the discoms or utilities. The MNRE and NRVN also manage a payment guarantee fund to insure NRVN against losses should the power remain unsold or the buyer default on payments. The Indian Renewable Energy Development Agency is a public

Table 5.1 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 or rooftop (megawatts)	1,000–2,000	4,000–10,000	20,000
Off-grid solar applications (megawatts)	200	1,000	2,000
Solar hot water collectors (square meters)	7 million	15 million	20 million
Rural solar lanterns or lighting (systems)	n.a.	n.a.	20 million

Source: CEEW and NRDC 2012.

Note: n.a. = not applicable.

limited government company that operates as the MNRE's financial arm and finances solar PV projects.

Three sets of policies operate to create the strategic environment within which private developers are functioning: (a) the NSM as the backdrop; (b) state policies, which could either complement the mission or offer alternative policy designs from which private developers could choose; and (c) non-NSM national policies, particularly the RPOs and RECs.¹

Three sets of private sector stakeholders are involved in ensuring the success of the NSM:

- *Project developers*, who bid for projects and, if successful, are primarily responsible for commissioning projects on time to supply the committed amount of solar-generated electricity into the grid.
- *Engineering, procurement, and construction contractors*, who implement projects for developers and have expertise in building projects and understanding on-the-ground challenges that affect project completion.
- *Financiers*, including Indian commercial banks, Indian nonbanking financial institutions, and international funding channels (including multilaterals, government-channeled funds, and public-private funds), which complement a developer's equity contribution by providing debt, loan guarantees, or risk insurance in order to commission the solar plant.

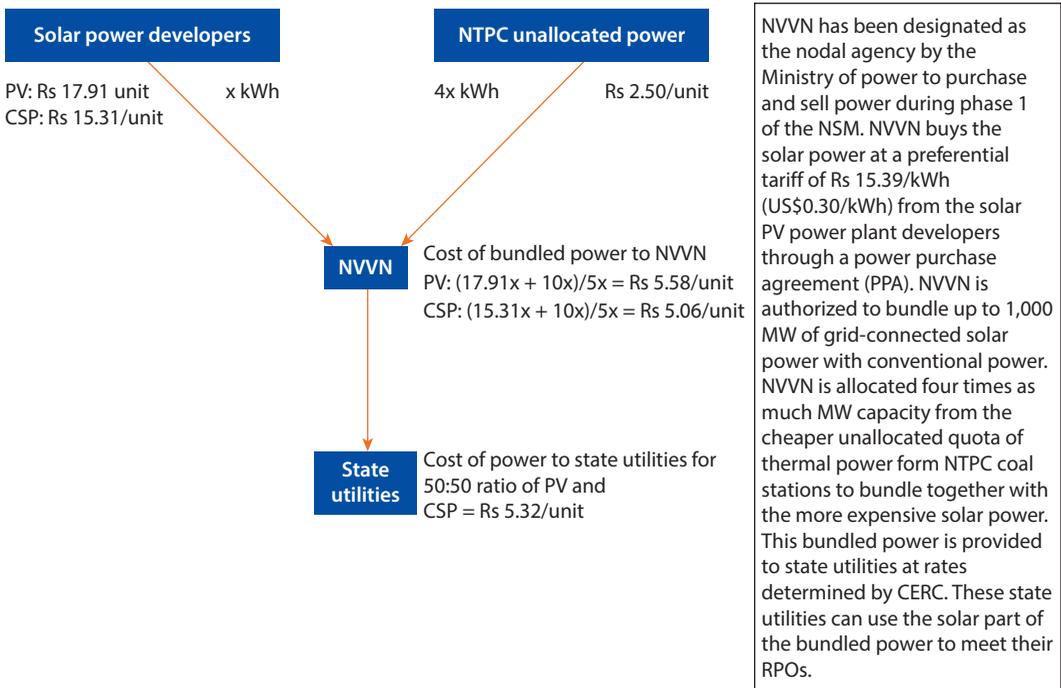
Progress to Date

India's total solar power installation currently stands at 2,208 MW, of which 661 MW have been contributed from projects selected under the NSM. The balance is from the state schemes for solar power development, with 70 percent coming solely from Gujarat. Madhya Pradesh is looking to add another 800 MW of solar power by June 2014.

Phase 1 of the NSM aimed to ramp up grid-connected solar energy to 1,100 MW by 2013, with 500 MW of PV power, 500 MW of concentrated solar thermal power, and 100 MW of rooftop PV power. However, this did not materialize, and just 252.5 MW of new capacity was added under the NSM during 2010–13. The targets were initially perceived as too ambitious, because India had little solar PV and no solar thermal projects in 2010. However, the market has grown tremendously with an increased number of developers, lower prices, and interested financial institutions. As of March 26, 2012, there was a total of 506.9 MW of installed capacity. The central government conducted two batches of reverse auctions, offering feed-in tariffs and long-term PPAs to the selected least-cost developers. The feed-in tariffs to developers were complemented by support to power utilities (discoms) through the bundling of solar power with thermal power, reducing the average per unit cost of solar power (figure 5.1).

Eight states have participated in phase 1 installations (PV and solar thermal). Rajasthan is in the lead by far (see table 5.2).

Figure 5.1 Bundling of Power Scheme: An Innovative Mechanism to Reduce the Price Burden of Solar



Source: Renewable Markets India 2011.

Note: CERC = Central Electricity Regulatory Commission; CSP = concentrated solar power; kWh = kilowatt-hour; MW = megawatt; NTPC = National Thermal Power Corporation; NSM = National Solar Mission; NVNVN = NTPC Vidyut Vyapar Nigam Ltd.; PV = photovoltaic; RPO = renewable purchase obligation.

Table 5.2 State Participation in Phase 1 Installations
Megawatts

State	Batch 1 (2010–11) allocation	Batch 2 (2011–12)
Rajasthan	PV: 100 ST: 400	PV: 295
Gujarat	ST: 20	—
Maharashtra	PV: 5	PV: 25
Karnataka	PV: 5	—
Tamil Nadu	PV: 5	PV: 10
Andhra Pradesh	PV: 15 ST: 50	PV: 20
Orissa	PV: 5	—
Uttar Pradesh	PV: 5	—

Source: CEEW and NRDC 2012.

Note: PV = photovoltaic; ST = solar thermal; — = not available.

For both batches of phase 1, the central government used the reverse auction as a price discovery mechanism. Reverse auctions have two main benefits. They allow government procurers to select projects based on the lowest cost (thereby keeping the burden on fiscal resources and taxpayers low) and ensure that a price-based selection process will be fair and transparent. Project developers bid

on discounted tariffs set by the Central Electricity Regulatory Commission. A 5-MW parcel-size requirement for batch 1 and 20-MW maximum parcel-size requirement for batch 2 opened the market for a broad range of companies to enter the sector, as long as they met the criteria set out into the guidelines.

Making headlines in late 2011, competitive bidding for NSM's second batch of projects in phase 1 drove prices for grid-connected solar energy as low as Rs 7.49/kWh (US\$0.15/kWh), approaching grid-parity with fossil-fuel-powered electricity. Phase 1 also attracted large conglomerates and new players into the solar market. During the mission's first phase, more than 500 bidders competed for 63 projects allocated during two reverse auctions, driving prices to record lows. New solar energy investments in India increased to more than Rs 12,000 billion (US\$2.5 billion) in 2011. This was in a general context of investments in the overall renewable energy markets in India reaching approximately Rs 51,000 billion (US\$10.3 billion) in that year, that is, solar projects accounted for about one-third of the investments. Bid euphoria, however, is wearing off, and serious questions remain as to whether the mission's phase 1 projects will meet commissioning deadlines.

During batch 1's reverse auction process, 36 projects were selected, with nearly 400 developers bidding in late 2010. A total of 140 MW was allocated to 28 PV projects and nearly 470 MW to seven solar thermal projects. The central government also migrated existing solar projects to count toward the National Solar Mission, at a premium tariff of Rs 17.91/kWh (US\$0.45/kWh), providing an additional 84 MW of migrated capacity.

The central government started the reverse auction at Rs 17.91/kWh (US\$0.45/kWh). The lowest bid price was Rs 12/kWh (US\$0.32/kWh). Because two PV projects failed to meet NRVN requirements, the projects were withdrawn from the process. Nineteen of the 36 batch 1 projects are located in Rajasthan. Major challenges and delays have affected the commissioning of batch 1 projects, which were all due for commissioning by January 2012.

By early 2012, the central government had fined 14 PV project developers for failing to meet their commissioning deadlines and had warned another 14. By late March 2012, 100 MW of PV projects were considered commissioned, and the remainder were to be commissioned shortly, but some experienced further delays. As the mission moves forward, compliance with deadlines will be a main focus in order to maintain the credibility of the government's policies and guidelines, as well as its enforcement capabilities.

India's batch 2 reverse auction sent ripples through international solar markets. The lowest winning bid, by French company Solairedirect, was Rs 7.49/kWh (US\$0.15/kWh) for a 5-MW plant. This price was impressively lower than markets had predicted, suggesting that solar energy could attain grid parity with traditional energy sources sooner than initially anticipated.

Current Indian grid-power prices in the top energy-consuming states range from approximately Rs 3.90/kWh (US\$0.08/kWh) in Andhra Pradesh to Rs 5.90/kWh (US\$0.12/kWh) in Rajasthan, with a nationwide average of Rs 4.70/kWh (US\$0.09/kWh). Commercial and industrial power prices

are generally higher, making the lowest winning bid of Rs 7.490/kWh (US\$0.135/kWh) very close to the higher-end grid power price—just Rs 1.60/kWh (US\$0.03/kWh) short of grid parity and at parity with diesel. Batch 2's progress toward grid parity was widely remarked on internationally.

In Batch 2, 22 companies were awarded contracts, with a total of 27 winning bids. Welspun Energy Ltd., Azure Power, Mahindra Solar, Green Infra Ltd., and Jakson Power won multiple projects, with Welspun Energy Ltd. securing the maximum 50-MW allotment for a single company. Green Infra Ltd. and Mahindra Solar secured 40 MW and 30 MW, respectively. All but three of the winning batch 2I bids were for projects located in Rajasthan. The other three projects were in Andhra Pradesh, Maharashtra, and Tamil Nadu.

Although larger companies such as Reliance Energy Ltd. did not participate as aggressively as expected during batch 2, some of these companies are undertaking big projects through state-level programs, such as the 40-MW Dhanu power project in Jaisalmer, Rajasthan, by Reliance Energy Ltd. The NSM has created momentum at both the central and state levels, as demonstrated by falling prices at the state level, too. Although developers view state-level solar programs as more profitable than the national program (because of higher feed-in tariffs and other state-level incentives), they typically have more certainty of being paid through NRVN under the NSM.

Although largely praised, the reverse auction has also been criticized. Some observers have raised concerns about the prices being driven so low that projects are financially unviable. The reverse auction process has also been criticized for not adequately vetting bidders, because the eligibility criteria simply required that bidders have a net worth of about Rs 150 million (about US\$3 million). The resulting selection of some inexperienced, small developers quoting very aggressive prices has raised fears that many projects may not be commissioned. In addition, inadequate vetting and monitoring have also led to accusations that some large companies have exploited guidelines and may corner a significant market share of NSM projects.

In phase 1, engineering, procurement, and construction (EPC) contractors have also risen as a central force in the emerging solar energy market. Project developers with limited experience in the solar market have relied heavily on their EPC contractors to support their projects with potentially unsustainable bid prices. The role of an EPC contractor can cut both ways. On the one hand, EPC contractors have experience executing projects, and the more experience they gain, the further marginal costs of installing additional projects could be reduced. On the other hand, too much reliance on an EPC contractor can also blur the distinction between the project developer, who bears the ultimate responsibility for producing solar electricity, and the contractor. Projects should ultimately be selected after due diligence is performed on both developers and associated EPC contractors.

Phase 1 is also a mechanism to test and evaluate the performance of project developers and to allow many domestic and foreign developers to enter the Indian solar market. One view holds that though the Indian solar energy market

has immense potential, it will ultimately consolidate to support only 8–10 primary developers. The significantly lower number of companies participating in batch 2 bidding, as compared to batch 1, is an early sign of such consolidation. The experience of other solar markets, such as that in California in the United States, suggests that consolidation is a sign of a maturing industry. In India, companies such as Welspun Energy Ltd., Azure Power, Mahindra Solar, and Lanco Infratech Ltd. are starting to dominate the grid-connected solar market. Although the batch 2 50-MW limit per project developer remains a low limit for a growing market, consolidation of companies is likely to continue as the market matures.

Clearly, state-level solar programs are having an effect as well, and NSM is not the only industry driver. As phase 1 bidding was underway, several states launched their own solar energy programs. For example, Welspun Energy Ltd. began new projects under Gujarat's policy and also competed for Karnataka's allotments. Similarly, Azure Power has a 2-MW solar power plant under operation in Punjab and Maharashtra State Power Generation Company Ltd. (Mahagenco) is working to commission a 150-MW plant in Maharashtra. Valuable experience and scale from multiple projects are giving these bidders the confidence to bid low and yet be profitable. Both batches of phase 1 were considered a success, but it is too early to tell yet whether individual selected projects can claim success. The central government and states will need to increase their levels of coordination given the increased scale of phase 2 projects.

The Indian banking sector has not been as enthusiastic toward lending to solar energy projects as it has been for thermal coal-based energy projects, because it perceives solar energy as an unproven technology. Lenders have also expressed concerns about the poor financial health of discoms as a big risk, even though this is a system-wide issue and not unique to the solar industry. Although innovative approaches such as bundling thermal power with solar power have reduced the cost burden on discoms for already-signed PPAs, uncertainty about the continuity of such schemes creates additional concerns for stakeholders who are assessing repayment risks for the future.

For phase 1, project developers were required to achieve financial closure within 180 days after signing a PPA with NRVN. Arranging financing for projects presented challenges, and goals were met in accessing domestic and overseas debt funds and using developers' own company equity. While equity financing may have largely helped to meet the relatively small scale of investments needed in phase 1, it will not be able to support the higher targets for phase 2 where it is estimated that up to US\$20 billion will be required to reach implementation targets. Phase 2 will therefore require an active government role to give financial players the confidence to invest in Indian solar projects.

Concrete actions that can be taken to improve commercial banks' perceptions and address their lack of information concerning the sector include the following:

- Documentation of successful projects' track records and whether performance claims can be achieved.

- Documentation of technological effectiveness (unlike wind turbines, which are certified by an industry body, there is no equivalent certification of solar components).
- Irradiance and insolation data about different parts of the country to underpin claims for site-specific generation estimates.
- Focused channels for dissemination of solar project performance information to banks to increase the understanding of the solar industry among potential lenders (there are more than 170 banks and 80,000 bank branches in India).

Potential Bottlenecks to Meeting Commissioning Schedule Deadlines

Acquiring Land and Obtaining Requisite Clearances

Land costs are usually only 5 percent of total project costs; however, local authorities are understandably slow to convert land-use designations from agricultural to nonagricultural. After an allocation under a lease or sale by a state government, reviewing of local claims on the land presents an additional hurdle. Locating projects in areas of high solar irradiance, close to the power grid, and with adequate resources and infrastructure is also a challenge, especially given India’s limited geographic mapping and limited data on solar irradiance. The grid proximity and irradiance challenges are compounded by traditional difficulties faced by nearly all energy projects, such as poor grid infrastructure, transmission problems, and chronic power shortages. Land development options are shown in table 5.3.

Table 5.3 Solar Project Land Development Options

<i>Land ownership</i>	<i>Key features</i>	<i>Advantages for developers</i>	<i>Disadvantages for developers</i>
Developer purchased and SPV owned	SPV owns the land on its balance sheet	Full flexibility in choice of location Use of land as collateral Option of sale or renewal at end of project life	High up-front costs Challenging process if land-use category must be changed or if there are multiple claims
Lease by government	Government purchases or earmarks land for solar development Lease periods typically match project life (for example, 30 years)	Lower up-front investment in land cost Ability to spread costs over project life and match revenues with costs Preapproved clearances and permits	Less flexibility in choice of location Limited opportunities to lease government land Increased government interface and processes
Solar park	Government or private developer acquires land Solar parks usually include incentives such as permits for developers and provide dedicated infrastructure to evacuate power	Economies of scale in procurement and permitting Faster and more reliable project execution with fewer risks for developers with well-planned solar parks	High reliance on government for correct siting and assessment of optimal solar resource Weaker negotiating position with respect to government and solar park developer

Note: SPV = special purpose vehicle.

Power Evacuation: Grid Connectivity and Proximity

There is currently a mismatch between the speed at which solar power projects can be set up and the time needed to provide the supporting infrastructure. Grid connectivity for utility-scale solar projects depends on grid capacity, proximity, and availability. Many project developers have difficulties with siting projects in areas with sufficient grid capacity, resulting in increased costs and project commissioning delays. There have been questions on whether the government should invest in substations and transmission facilities before projects are set up. Yet, for current projects in Gujarat and Rajasthan, where the majority of solar PV power is being deployed, grid connectivity has not been a major issue because of the states' approach to using solar parks. Decisions on siting the solar parks have been made on the basis of connectivity to the grid. As the market grows, however, and larger capacities are commissioned (particularly in phase 2), planning for future grid upgrades must receive emphasis in advance so that the infrastructure is available as projects are commissioned.

There is also a need for greater clarity on who is responsible for the last-mile infrastructure, that is, how solar projects are physically connected to the grid and who bears the cost of making that connection: state utilities or project developers. The answer to this question seems to vary according to state or central government policies. In some cases, developers who had not anticipated the last-mile construction cost have seen project costs exceed allocated budgets. The NSM specifies that state agencies and utilities are responsible for evacuating power from project sites to transmission lines. There is no additional national-level support for power evacuation. The cost for last-mile infrastructure can be 5–10 percent of total project costs, according to a 5-MW phase 1 developer in a statement to the media.

Community Involvement and Habitat Protection

With 5–10 acres required per MW, ground-mounted solar power is a land-intensive operation. The majority of phase 1 grid-connected solar projects are in remote locations where the primary contentious issues are conflicting land claims and land allocation for animal grazing. More social and ecological issues may surface as the NSM ramps up, and it is critical for the overall success of the mission that government policies and developers minimize negative effects on the local communities and ecosystems.

Note

1. Because renewable resource distribution is unequal across India, a system for trading RECs has been implemented to allow state discoms, which are the responsible entities, to meet their RPOs. Strong enforcement of RPOs will be fundamental to the success of the REC market and will in turn lower the costs of implementing solar projects by ensuring markets for solar power.

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Financing of the Power Sector

Key Messages

- Given the high level of commercial bank exposure to power sector risk, the distribution sector's losses threaten to derail the power sector and potentially also the health of the financial sector.
- The macroeconomic outlook is negative, and the private sector will increasingly be competing with the government for declining private savings.
- The Ministry of Power is introducing a ratings system for distribution companies that analyzes their operational and financial performance and compares them to each other.
- Commercial banks are cutting back their exposure to the power sector.

Distribution Sector Losses and Their Effects

With increasing losses, and inadequate subsidy support from the state governments, most of the state distribution utilities have been forced to increase their level of borrowings, mostly bank borrowings, beyond their sustainable limits. In the past, banks have generally relied on government guarantees for taking loan exposures to the state power distribution utilities and have continued to increase their lending exposure sizably. At present, bank borrowings (mostly short-term borrowings) fund a major portion of the losses of state distribution utilities. With signs of severe financial strain emerging in the distribution sector in certain states, lending institutions, especially banks, have become cautious about new lending. As a result, the fund flow to the entire state power sector has been adversely affected. Although commercial banks have large exposure, two central government-owned lending agencies are the largest lenders.

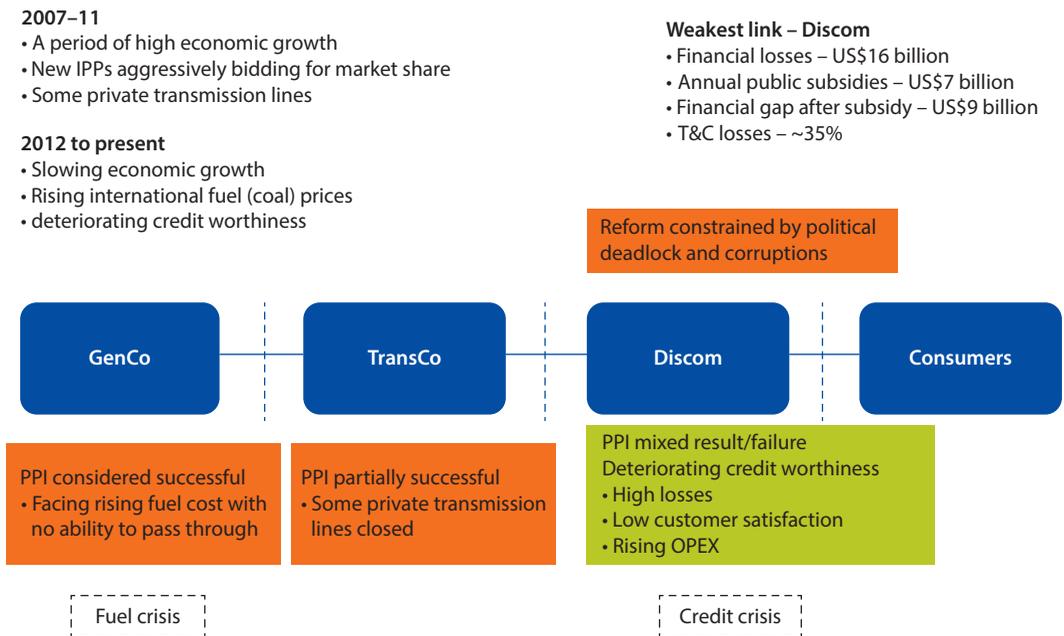
The central government established the Power Finance Corporation (PFC) in July 1986 to exclusively focus on financing and developing the country's power sector. Today, PFC is the single-largest lender to the Indian power sector and supports about 23 percent of the country's installed power generation capacity.

Rural Electrification Corporation Limited (REC) is another leading public infrastructure finance company in India’s power sector. The company finances and promotes rural electrification projects across India and also provides loans to the central and state power sector utilities, state electricity boards, rural electric cooperatives, nongovernmental organizations, and private power developers.

The electricity value chain in India is summarized in figure 6.1, which also captures the source of financial pressure in the system.

Given the high level of commercial bank exposure to power sector risk, the distribution sector’s losses threaten to derail the power sector and also the health of the financial sector. The banking sector’s exposure to the power sector continued to increase in absolute terms, and nonperforming assets (NPAs) increased nearly tenfold between September 2011 and September 2012, from Rs 12 billion to Rs 117 billion (US\$218 million to about US\$2 billion), as illustrated in figure 6.2.

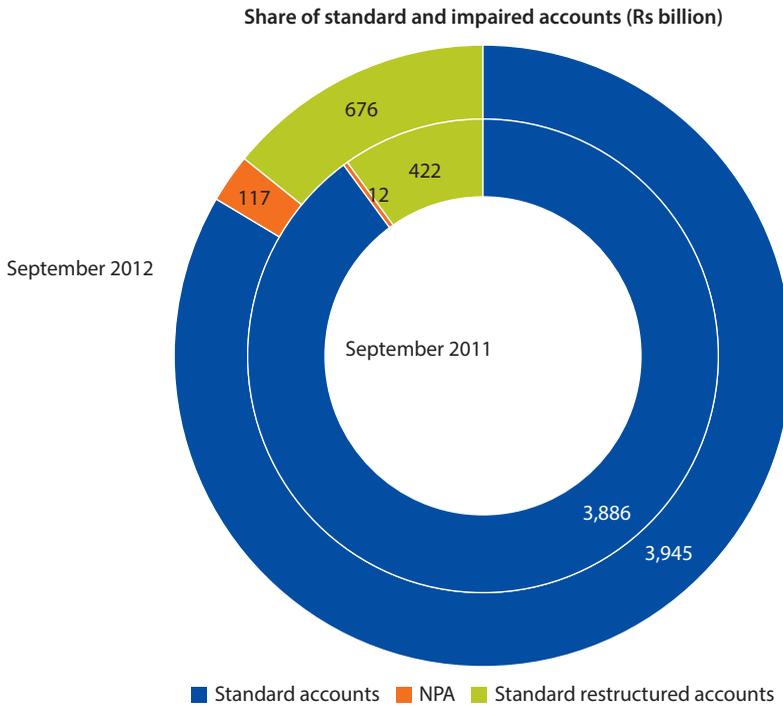
Figure 6.1 Summary of Electricity Value Chain under Pressure



- High commercial and technical losses as well as low collection rates in combination with compromised political economy puts high pressure on DisCos. PPAs with IPP force dispatch of expensive plants, pressuring tariff. Attempts to bring private expertise delivered mixed results.
- The GenCos are facing financial pressure because of tight PPA tariffs and no pass through ability on rising fuel prices, while simultaneously facing reduced credit worthiness of DisCos.

Note: Discom = distribution company; GenCo = generation company; IPP = independent power producer; OPEX = operating expenses; PPA = power purchase agreement; PPI = private participation in infrastructure; T&C = technical and commercial; TransCo = transmission company.

Figure 6.2 Exposure to Power Sector



Source: RBI 2012, 32.

Note: NPA = nonperforming asset.

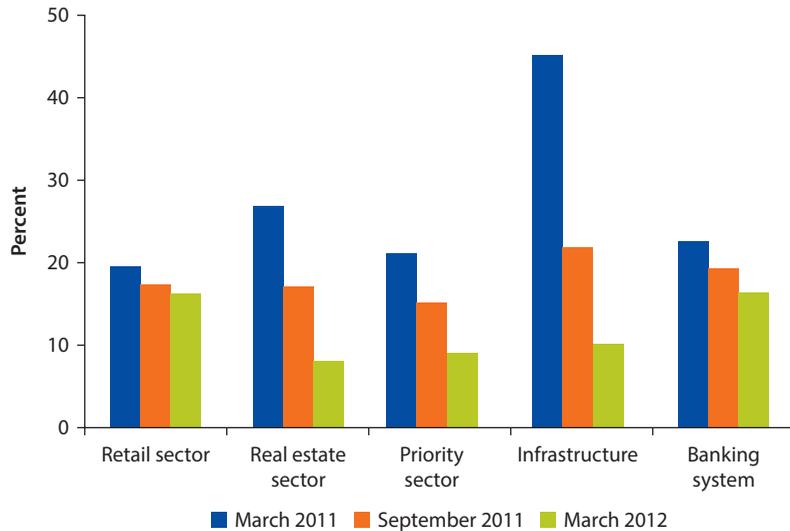
The growing number of NPAs in the power sector likely accounts for the decrease in commercial lending to the power sector. Figure 6.3 shows the decrease (as shown in the infrastructure data in figure 6.3).

Macroeconomic Outlook

The macroeconomic outlook beyond 2012 is negative at present, and the private sector will increasingly be competing with the government to access declining public savings. The Reserve Bank of India conducted a sample study of 12 corporations with high exposure to infrastructure, particularly power. The bank found (a) sharply increasing ratios of debt to equity and debt to earnings before interest, taxes, depreciation, and amortization and (b) decreasing interest coverage. Those findings point to the increasing vulnerability of both the corporations and their lenders (table 6.1).

Central Government Approach

Over the past decade, the reaction of the central government to the financial crisis in the distribution sector has been rather muted, although at least two centrally funded bailouts were offered to state utilities in March 2001 and

Figure 6.3 Growth Rate of Bank Credit to Selected Sectors

Source: RBI 2012, 32.

Table 6.1 Causes for Increasing Vulnerability of Corporate Entities

<i>Element in decline</i>	<i>Element on the increase</i>
<ul style="list-style-type: none"> • Household savings • Growth 	<ul style="list-style-type: none"> • Inflation • Current account deficit • Rupee depreciation

September 2012, respectively. However, the central government also approved a new financial restructuring plan for state distribution companies in September 2012 to accompany the latest bailout, which was not the case earlier, when no strings were attached. The September 2012 scheme offers central government support conditional on measures for both state distribution companies and state governments successfully achieving the financial turnaround of distribution companies. The scheme proposes that (a) 50 percent of outstanding short-term liabilities would be converted into respective state government guaranteed bonds, and the remainder be rescheduled at favorable rates; (b) committees at state and central government levels would monitor progress of the turn-around measures; and (c) the central government would provide incentives through grants for accelerated aggregate technical and commercial loss reduction beyond the targeted levels under the central electricity reform scheme (Restructured Accelerated Power Development and Reforms Programme).

In March 2013, the Ministry of Power (MOP) finally undertook leadership with respect to the financial crisis in the distribution sector and released a rating of distribution utilities' financial health to help lenders assess the risks of

specific distribution utilities. The utilities were rated on the basis of seven parameters, including financial status and compliance with regulatory norms. The integrated ratings shown in table 6.2 are determined on an annualized basis and range from A+ to C (A+ is the maximum, C is the minimum, and 100 is the total score).

The proposed grading scale of A+ to C is different from the existing, standard rating scale adopted by credit rating agencies (that is, AAA to D), because the standard credit rating measures only the degree of safety regarding timely servicing of financial obligations based on the probability of default. In contrast, the new grading exercise shown in table 6.2 analyzes the operational and financial health of the distribution entities using the rating framework approved by the MOP. Furthermore, the standard credit rating for distribution utilities entails comparison with unspecified corporations, whereas the MOP's newly developed integrated rating exercise compares the entity with other distribution utilities only.

Recommended Holistic Approach

In general, bailouts create a moral hazard (that is, allow a return to business as usual) unless accompanied by strong monitoring measures. The key issues are ensuring the following: state utilities meet efficiency targets, regulators set adequate tariffs that are revised annually in line with existing legal requirements, financial institutions maintain hard budget constraints, and state governments pay subsidies as promised. A holistic approach would improve the investment climate for generation and commercially sound operation of distribution utilities, achieve a better balance between demand and supply, and prevent the system from again reverting to crisis. Aspects to be addressed for financial sustainability of the state power sector are discussed below.

Table 6.2 First Integrated Rating for State Power Distribution Utilities, March 2013

<i>Score distribution</i>	<i>Grade</i>	<i>Number of utilities</i>	<i>Grading definition</i>
Between 80 and 100	A+	4	Very high operational and financial performance capability
Between 65 and 80	A	2	High operational and financial performance capability
Between 50 and 65	B+	11	Moderate operational and financial performance capability
Between 35 and 50	B	10	Below average operational and financial performance capability
Between 20 and 35	C+	8	Low operational and financial performance capability
Between 0 and 20	C	4	Very low operational and financial performance capability

Improvement of the Financial and Operational Performance of Distribution Utilities

Initially, the focus should be on the six states that are responsible for 70 percent of the accumulated losses of the distribution sector. Action should be taken with regard to service delivery, tariffs, efficiency, and profitability:

- *Service delivery.* The willingness of consumers to pay for power is intrinsically tied to the quality and quantity of power received. Utilities can improve their credibility with consumers by improving customer service, providing relevant service information, and responding to complaints in a timely fashion.
- *Tariff revisions.* Regular, transparent tariff revisions that respond to increases in costs and provide utilities with a reasonable return are critical to ensuring that utilities earn profits that can be reinvested into system upgrades and performance improvement measures. Reduction of cross-subsidies, as mandated by the National Tariff Policy, is another key action.
- *Efficiency.* The reduction of distribution losses must be a priority. In addition, efforts need to be made to increase transparency, collect reliable energy data to guide management, use performance management systems to enhance accountability, and implement appropriate measures to give management and employees a stake in improving performance.
- *Profitability.* Utilities need to earn a profit to be viable, to be able to invest, and to be able to upgrade their service to their consumers.

Commercial Operation throughout the Value Chain

The legislative framework for the power sector is robust. However, although unbundling and other reforms have been undertaken on paper, they have not always been implemented fully. The Electricity Act of 2003 and associated reforms aimed to disrupt the single-buyer model, create competition in distribution and generation through open access and competitive bidding, ring-fence utilities from political interference, and create incentives for utilities to improve service and performance. Today, however, many state utilities continue to operate as de facto government agencies without functional independence. For a sound power sector, power utilities must operate on commercial principles. Subsidizing the provision of power to poorer consumers is not inconsistent with good sector performance, provided that such subsidies are transparent, targeted, and actually paid on time.

West Bengal Power Sector Reforms

West Bengal state has been a leader in implementation of reforms. Since the unbundling of the erstwhile West Bengal State Electricity Board (WBSEB) in 2007, all of the successor entities have been profitable each year, and only the distribution company received a small government subsidy in fiscal year (FY) 2010/11 targeted toward the poorest consumers.

Before reforms, the WBSEB was inefficient, operated at a loss, and required budget support to sustain its operations. West Bengal's approach to reform was gradual. Before unbundling the WBSEB, West Bengal reviewed the strengths and weaknesses of the existing framework, identified best practices from international and Indian experience, developed a financial and institutional restructuring plan built on credible data, and engaged in intensive stakeholder consultations throughout the process to ensure commitment to the reform agenda at all levels. The WBSEB adopted computerized billing, 100 percent feeder metering, strict monitoring and vigilance activities to prevent electricity theft, and near 100 percent metering of consumers. The state government also induced changes in top management by appointing seasoned bureaucrats with strong management and business acumen.

In addition, West Bengal has been exceptional by consistently raising tariffs—each year from FY2008/09 through FY2011/12. However, the West Bengal distribution utility received regulatory approval to raise tariffs only after three years of significant improvements in power supply and energy access, improved customer service (including universal metering and computerization of billing), and negligible dependence on state subsidies.

Improvement of Corporate Governance

The autonomy and functioning of boards of directors of state power utilities can be improved as can the length of directors' management tenures (managing directors of most state utilities have an average tenure of about one year). Timely audits of finances and information on energy flows are also necessary inputs to performance improvement.

Reference

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Emerging Issues and Proposed Approaches for the Indian Power Sector

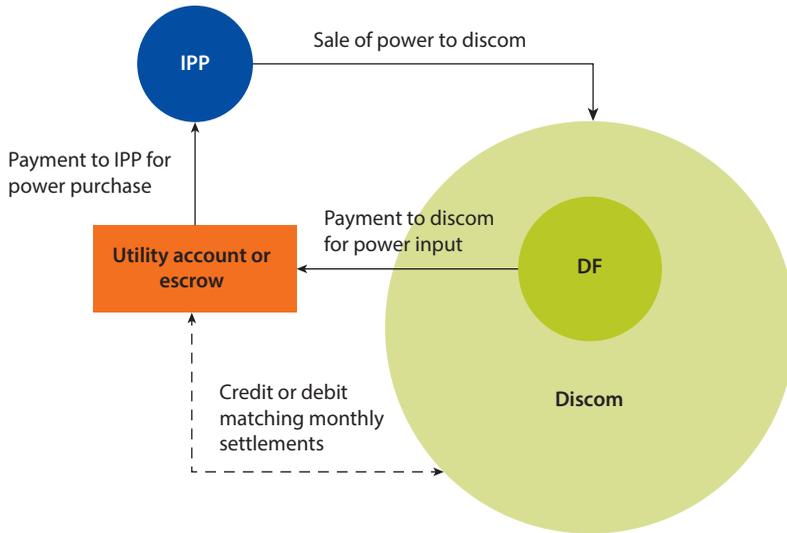
Emerging Issue: The Need for Better Partnership Mechanisms with the Private Sector

First Proposed Approach: A Combined Generation and Distribution Contract

Loss reduction and efficiency improvement have been the main bidding variables to date in competitive selection of private partners for distribution. However, these factors need not remain the sole criteria for looking at private sector participation in the power distribution segment. There are now several private sector players who have built up significant portfolios in power generation projects and who are keen to participate in the distribution business so that they can contribute to reducing their own risks in the generation segment. Combining the procurement of power (case 1 bid) with a distribution franchisee (DF) bid would create a win-win situation for the licensee (state utility) and the franchisee (case 1) generation bidder (figure 7.1). Private sector participants may be able to add significant value in terms of power procurement cost-related efficiencies, if the revenues from the sale of power from their own generating assets are financially secured through revenues expected to be sourced from distribution franchise areas that they also operate. The whole cost of intermediation through the state utility can be avoided, which can lead to lowered risk perceptions, thereby resulting in lower power costs. Evidence already shows that the outcome of case 1 bids run by financially stressed licensees (utilities) have yielded higher tariffs in comparison to the outcomes of projects run by more progressive and fiscally sound states such as Gujarat.

In view of those results, and if one considers that several major private sector power generation companies in the country also have expertise in the power distribution businesses, bundling a power procurement bid under a case 1 bidding route with a distribution franchise bidding process could be a win-win situation for licensees. This situation could work for an identified

Figure 7.1 Combining Distribution Franchisee Bid with Case 1



Note: The dashed line is not an actual cash flow, but rather a monthly settlement. The bold line is delivery of power, and the notched lines are flow of money. DF = distribution franchisee; discom = distribution company; IPP = independent power producer.

urban area with adequate revenue potential. For example, a special purpose escrow fund could be established to channel the payables from the DF for energy input received from the licensee (state utility) to the receivables of the generation business against sale of power to the licensee by the selected developer. In other words, the state utility remains involved, but the power seller knows that the revenues for the sale of power to the licensee from its generation business are not dependent on the parlous financial condition of the state utility. Instead, the revenues to pay for the power are emanating from the DF, which has direct access to customers. Furthermore, the DF would be controlled by the same entity that is supplying the power. The state utility (licensee) is effectively serving an intermediary function, and the benefits are flowing to the franchisee’s customers in the form of cheaper and more reliable power, and possibly also to the customers who are directly served by the state utility—that is, those outside the franchise area. The special purpose escrow fund guarantees that the funds from the DF are not comingled with the rest of the state utility’s revenues, but are ring-fenced for payment to the power generation company.

To reiterate, the arrangement discussed would substantially eliminate the payment security risk associated with the sale of power, as perceived by the selected developer, particularly because the size of the DF ring-fenced area may be progressively increased in concentric circles on the basis of good performance and customer satisfaction with improved power supply quality. It may, therefore, hold immense potential for the licensee (state utility) to be able to access

competitive or lower-priced power to meet the state's supply requirements at lower costs resulting from lower risk perceptions.

Second Proposed Approach: Private Sector Engagement for Project Management Capacity, Information Technology Expertise, and New Technology for the Grid

Another model could be one to promote new, specific, and capital-intensive technology interventions, such as advanced metering infrastructure and SmartGrid initiatives, under a franchisee-like private sector participation scheme in which the selected franchisee is required to undertake capital investments related to specific items. The revenue model could be similar to that of the DF, wherein the franchisee retains revenues from sale of power to retail customers and quotes an input rate for power supply at a predetermined input point to be provided by the licensee. This arrangement is similar to the existing DF model, except it does not leave the network upgrading investment strategy to the discretion of the franchisee but, instead, specifies what technologies shall be used. These technologies will eventually revert to the public sector when the franchise agreement ends.

Third Proposed Approach: Urban Franchisees Partner with Rural Franchisees, as a Condition of the Urban Franchise Agreement, to Build Capacity and Upgrade the Rural Franchisee's Scope of Work

Rural franchisees are essential and have been helpful for utilities in improving the potential revenue collections from remote rural areas, which licensees have traditionally ignored. Rural franchisees are becoming more important as more and more villages and consumers are getting electrified and connected to the grid, leading to sharp increases in the demand for, and potential sale of, energy in rural areas.

There are more than 37,000 rural franchisees operating across 18 states, though at present almost all of them are collection franchisees with limited responsibilities. Revenue collection franchisees need to be gradually converted to distribution transformer or feeder input-based franchisees. This conversion will ensure that the franchisees can more meaningfully contribute to transmission and distribution loss reduction and network operation and maintenance, in addition to fulfilling their present responsibility of revenue collections.

Urban franchisees are unlikely to partner with rural franchisees voluntarily. However, one possibility would be to include a license condition that an urban franchisee partner with a rural franchisee of its own choosing (in their state or another) and invest in that rural franchisee's training and capacity building in a way that can measurably improve the rural franchisee's productivity and performance. If appropriate capacity-building measures are taken to impart the requisite skill sets to the rural franchisees, then revenue collection franchisees could gradually be converted to input-based franchisees within a predetermined time frame. The training programs introduced by the Rural Electrification Corporation Ltd. through the Central Institute for Rural Electrification could also be leveraged.

Most important, partnerships structured with winners of bids for urban franchises would be expected to introduce rural franchisees to a commercial culture, develop their skills, and expose them to technology.

Final Thought

The road to recovery and high performance remains a long one. Much has been learned on the way, and many adjustments and modifications have been admirably made. New adjustments are needed to deal with the fuel risks that have recently emerged and to make better use of private service delivery and new technologies to reduce losses in power distribution. The most important challenges still remain: fostering governance and leadership and reaching a consensus that the power sector should not be treated as a source of political patronage. No imported expertise or technique can expedite the political will.

Once the political will is in place to fix the “leaking bucket” (as described in the memorable words of Shri Deepak Parekh¹), no one will be able to hold back the power sector. With enough capable and experienced private investors, capital and expertise are poised to propel the sector forward into the 21st century and put wind in the sails of India’s overall economic growth. Accountability and commercial focus will transform the sector.

Note

1. “India’s power sector is a leaking bucket; the holes deliberately crafted and the leaks carefully collected as economic rents by various stakeholders that control the system. The logical thing to do would be to fix the bucket rather than to persistently emphasize shortages of power and forever make exaggerated estimates of future demands for power. Most initiatives in the power sector (IPPs [independent power producers] and mega power projects) are nothing but ways of pouring more water into the bucket so that the consistency and quantity of leaks are assured. ... Every MW [megawatt] of power produced today produces losses. Roughly speaking about 60% of the power produced is billed and about 60% of that is collected. Can we honestly run a power system sustainably in this manner?” (Shri Deepak Parekh, former Chairman of Infrastructure Development Finance Corporation, September 2001).

Update

This book analyzes the Indian power sector for the period from 1991 to 2012. Since then, several new bid processes have been conducted, particularly in distribution. The Ministry of Power (MOP) has recently taken steps to standardize bidding documents for selection of distribution franchisees (DFs). In addition, standard bidding documents (SBDs) for the generation sector have been completely overhauled, and changes are being considered in the transmission sector, but are not yet finalized. This chapter provides a brief update—up to April 2014—on the changes that have followed the period analyzed in this book.

Review of Progress on Selection of DFs

During the past two years, the states of Jharkhand and Bihar have run bid processes for appointment of a DF for a substantial portion of their supply area. A summary of those bid processes is provided in table 8.1.

Some standardization was seen in the requests for proposal (RFPs) issued during the period as evidenced in the incorporation of lessons and improvements in the previous rounds of bids. The MOP issued SBDs for the appointment of input-based DF in June 2012. The bidding documents in the state of Bihar issued during the subsequent period largely followed the SBD.

Although the number of participants or bidders in the recent bid processes has not greatly expanded, those processes have been far more successful in taking the method of appointing a DF to a logical conclusion. Of seven processes initiated since mid-2012, the distribution franchisee agreements (DFAs) have been signed for five DF areas, and the process for two areas has not yielded the desired results.

Major observations from the bid processes held since mid-2012 are as follows:

- **Utilities are increasingly trying to lean toward established and experienced players for larger and more important DF areas.** The Jharkhand utility for Jamshedpur and Ranchi and the Bihar utility for Patna DF area had set the eligibility condition in a manner that limited participation exclusively to the leading experienced private sector utilities such as Tata Power Company Ltd.,

Table 8.1 Bid Processes, Jharkhand and Bihar States, 2012–13

<i>Area</i>	<i>Area profile</i>	<i>Bidders</i>	<i>Successful bidder</i>
Patna, Bihar (2013 bid process)	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 2,133 MU • Consumers: 352,521 • Revenue: Rs 7.49 billion • AT&C loss: 41% 	No bidders	<ul style="list-style-type: none"> • Not applicable
Muzaffarpur, Bihar	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 339.53 MU • Consumers: 132,714 • Revenue: Rs 1.11 billion • AT&C loss: 56.23% 	GTL Ltd., Essel Group	<ul style="list-style-type: none"> • Essel Group • DFA signed • Operational since November 2013
Gaya, Bihar	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 330.84 MU • Consumers: 99,613 • Revenue: Rs 0.66 billion • AT&C loss: 68.25% 	GTL Ltd., Essel Group, DPSC Ltd.	<ul style="list-style-type: none"> • DPSC Ltd. • DFA signed • Handing over expected in May 2014
Bhagalpur, Bihar	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 314.52 MU • Consumers: 115,669 • Revenue: Rs 0.71 billion • AT&C loss: 67.90% 	GTL Ltd., Essel Group, DPSC Ltd., Subhash Projects	<ul style="list-style-type: none"> • Subhash Projects • DFA signed • Operational since January 2014
Ranchi, Jharkhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 1,500 MU • Consumers: 256,868 • Revenue: Rs 3.13 billion • AT&C loss: 41% 	CESC, Tata Power Company Ltd.	<ul style="list-style-type: none"> • CESC • Handing over pending • Independent audit delayed
Jamshedpur, Jharkhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 1,394 MU • Consumers: 247,939 • Revenue: Rs 3.5 billion • AT&C loss: 32.81% 	Tata Power Company Ltd., CESC	<ul style="list-style-type: none"> • Tata Power Company Ltd. • Handing over pending • Independent audit delayed
Dhanbad, Jharkhand	<ul style="list-style-type: none"> • Tenure: 15 years • Input: 959 MU • Consumers: 1.8 million • Revenue: Rs 2.13 billion • AT&C loss: 45% 	Essel Group	<ul style="list-style-type: none"> • Process aborted because of single bidder

Source: Deloitte research.

Note: AT&C = aggregate technical and commercial; CESC = Calcutta Electric Supply Corporation; DFA = distribution franchisee agreement; MU = million units.

CESC, Torrent Power Ltd., and Reliance Power Ltd. By the time these bid processes were initiated, the difficulties that newcomers to the sectors were facing at the operating DFs in Nagpur, Aurangabad, and elsewhere were well known. Therefore, with regard to the large and important areas being offered to the private sector for DFs, the distribution utilities have apparently been seeking to minimize performance risk by setting the qualification requirements to attract significantly experienced and established players only. Although the bid for Patna failed because of the unreasonable reserve price set by the Bihar State Electricity Board (BSEB), the Jharkhand State Electricity Board (JSEB) has been able to appoint CESC for Ranchi and Tata Power Company Ltd. for Jamshedpur as the respective DFs.

For smaller areas, which are not as attractive for large players, the utilities have set relatively relaxed qualification criteria for ensuring adequate participation and competition in the bids. Such areas include Muzaffarpur, Gaya, and Bhagalpur in Bihar and Dhanbad in Jharkhand.

- **Utilities lack adequate systems and processes to conduct bid processes based on reliable and auditable data.** The process for a third-party independent audit for the baseline data for Ranchi and Jamshedpur in Jharkhand has still not been completed despite signing of the DFA in December 2012. The quality of records maintained and systems and processes of the erstwhile JSEB pose substantial challenges for conducting a quality audit process. Therefore, despite the appointment of reputable auditors for undertaking the process over a year ago, the process has not been concluded so far.

However, BSEB, which also maintains poor records and has weak systems and processes in place, has chosen to proceed with the audit of the baseline records *before* the RFP stage itself. In the case of BSEB, no provision exists for any joint audit with the successful DF bidder, or any review at a post-award stage. The approach adopted by BSEB would stand only if the quality of the audits, which are being done upstream, is sufficient and balanced toward the interest of all parties. If the baseline information is found to be erroneous at a later date, there could be serious financial consequences for the private developers–DFs as well as BSEB.

- **Utilities continue to use their monopolistic strength to negotiate terms with private players.** Recent developments indicate that the distribution utilities, which happen to be the concessioning authorities in the DF appointment process, have been able to negotiate certain terms with the selected bidders *that are beyond those specified in the bid documents and DFAs*. Some of these instances are as follows:
 - In the case of Ranchi and Jamshedpur, wherein the independent auditors were expected to be appointed by the respective selected developers (with due approval from the JSEB), the JSEB has eventually made the selected developers agree to devolve the responsibility of appointing the auditor onto itself.
 - The bid documents and the clarifications issued during the pre-bid process had maintained that the funding of the ongoing, prepared, and approved schemes under the Restructured Accelerated Power Development and Reforms Programme (R-APDRP)¹ would be undertaken by the BSEB or the respective successor licensees, following the unbundling process. The DFs were told that they would be responsible for only the investments required over and above those in the R-APDRP list. However, the selected developers for Muzaffarpur, Gaya, and Bhagalpur have now been made to agree to take on the cost of the funding of the (R-APDRP) so-called “Part B investments,” through a back-to-back arrangement with the BSEB and successor licensees.

Issuance of SBDs for the Appointment of DFs

In June 2012, the MOP issued SBDs for appointment of input-based DFs. Given the nature and extent of inconsistencies that were prevalent in the previous rounds of bids, the issuance of recommended SBDs by the MOP has been seen as a major step toward standardizing the process for appointment of DFs.

Unlike the model documents published earlier by the Central Electricity Authority and the Forum of Regulators, the SBD issued by the MOP has addressed several important issues and attempts to balance the interests of all stakeholders. The SBD has already been used as the base document for the bid processes conducted in the state of Bihar for Bhagalpur, Gaya, Muzaffarpur, and Patna with due approvals from the regulator for the changes and adaptations made therein.

Several of the key elements of the SBDs identified and recommended from the review have been addressed in the SBD issued by the MOP. However, further scope potentially exists for improving the SBD with regard to a number of clauses that are still not addressed and are being treated on a case-by-case basis. These points are summarized in table 8.2.

Table 8.2 Elements Needing Improvement in Standard Bidding Documents

<i>Clause or aspect</i>	<i>Rationale for inclusion in an SBD</i>
Selection of urban franchisee area	Because of experiences of successful and failed DF attempts, empirical calculation of the “minimum energy input for the proposed area” is essential for identification of suitable areas and needs to be recommended by the Ministry of Power, in either the covering note or the annex to the SBD.
Prequalification criteria	The SBD prequalification criteria are too stringent and need to be relaxed to attract greater participation by prospective bidders in future DF bids. However, at present the utilities may adopt such relaxed criteria on a case-by-case basis depending on the size, attractiveness, and critical nature of the individual area(s).
Consortium	Allowing creation of a consortium is in the interest of attracting new players who have the financial capability to invest in the power sector but do not have the technical experience in the sector. Allowing the formation of consortiums would allow such players to take on a partner who could supplement their financial strength with the requisite technical capabilities.
Input rate and loss reduction trajectory	Providing a reasonable and achievable loss reduction trajectory will provide guidance to the utilities in fixing the same and for calculating the reserve prices in the bid documents. In the past, utilities have provided unreasonable loss reduction targets and reserve prices, leading to failure of several bid processes.
Commercial and management information systems and compatibility of information technology systems	Such systems should be included for better transparency and timely action in case of contractual default by the appointed DF.

Note: DF = distribution franchisee; SBD = standard bidding document.

Finalization of Key Terms of the Public-Private Partnership Model for Distribution

The final report of the Task Force on Private Participation in Power Distribution (headed by B. K. Chaturvedi) issued in July 2012 has recommended adoption of a proposed public-private partnership (PPP) model for prospective private sector participation in the power distribution sector.

The recommended PPP model requires identification of prospective areas that could be ring-fenced and carved out for a separate license under a special purpose vehicle (SPV). The shares in the SPV would then be sold to a private developer to be appointed through a competitive bid process under a design-build-finance-operate-transfer model. The assets in such carved-out area would continue to remain under the ownership of the state government or the incumbent licensee and would be transferred back to it at the end of the concession period. Although the state government would not have any equity in the SPV, it would be provided with an affirmative vote on certain issues of public policy through a golden share. The SPV would operate as a normal licensee under the purview of the concerned state electricity regulatory commission and therefore would have flexibility for conducting power purchases and undertaking all necessary investments essential for making a quality and reliable supply available to the consumers. Key features of the recommended PPP model are summarized in table 8.3.

Table 8.3 Key Features of the Recommended PPP Model

<i>Criteria</i>	<i>Feature</i>
Compliance with the Electricity Act of 2003	The concessionaire would be required to procure a distribution license under Section 14 of the act.
Feasibility report	The state government would need to engage an experienced and qualified firm as technical consultant to prepare the feasibility report, which would be provided to the bidders as part of the bidding documents.
Selection criteria	Selection criteria would be based on open, competitive bidding. All project parameters would be clearly stated upfront. The short-listed bidders would be required to submit their financial bids. The bidder who seeks the lowest grant or offers the highest premium would win the concession.
Concession model	A design-build-finance-operate-transfer model would be adopted.
Inventory of assets	Replacement or repairs of defective assets such as transformers, cables, and so on during the concession period would have to be carried out by the concessionaire, who may retain or dispose of the defective equipment that has been replaced.
Use of assets	The concessionaire would be given the exclusive use of the distribution assets, but the ownership of the assets would remain with the state government.
Concession period	The concession will be granted for a period of 25 years in accordance with the provisions of the Electricity Act of 2003.
Equity structure	The state government would not have any share in the concessionaire's company. The government would be provided with an affirmative vote on certain issues of public policy through a golden share.

table continues next page

Table 8.3 Key Features of the Recommended PPP Model (continued)

<i>Criteria</i>	<i>Feature</i>
Tariff	The tariff would be set in accordance with the provisions of section 45(3) (a) of the Electricity Act of 2003.
Wheeling and distribution charge	The wheeling and distribution charge would be predetermined on the basis of the projected investment, the likely costs of distribution, and the trajectory of transmission and distribution losses.
Continuation of financial support	The state government would have to provide substantial subsidies to the concessionaire to prevent a sharp rise in tariffs, especially during the initial years of the concession period. The document lists three elements of subsidy in the system that may need to continue during the initial phase: (a) direct tariff subsidy; (b) cross-subsidy; and (c) uncovered distribution losses.
Capital investment	Based on the feasibility report, the bid document shall specify the level of investment for an initial period, such as five years, to be made by the concessionaire for augmenting and upgrading the existing distribution system to specified standards.
Performance standards	Operation and maintenance of the distribution system are proposed to be governed by strict performance standards with a view to ensuring a high level of service to the users.
Loss reduction	In accordance with the concession agreement, aggregate technical and commercial loss reduction would be done yearly.
Transfer of assets	At the end of the concession period, the concessionaire would be required to transfer a fully functional distribution system to the state government.

Source: Government of India 2012.

The states of Jammu and Kashmir, Uttar Pradesh, and Assam are reportedly considering the award of identified areas to private developers under the PPP route. However, not much progress has happened to date.

Uttar Pradesh Power Corporation Ltd. had initiated a process for appointment of consultants for project formulation and undertaking of various preparatory activities for the award of Ghaziabad, Kanpur, Meerut, and Varanasi to private developers. However, the process was called off because of stiff resistance from employee unions.

Although the proposed model does not lead to any privatization of existing assets owned by the state government, it is still perceived as similar to full privatization. The efficacy and acceptability of the PPP model are yet to be established. The detailed transaction documents have not been prepared so far and could possibly be created together with a real transaction process. The next few years will be crucial for developing model cases under this route.

Impending Segregation of Wheeling and Supply License(s)

The MOP, by Notification No. 42/6/2011-R&R (Vol-III) dated October 17, 2013,² issued the proposed amendments to the Electricity Act of 2003, which are expected to be put up for debate and approval of the Lok Sabha (Lower House of Parliament, known as House of the People) during the 2014–15 winter

session of the Parliament. The proposed amendments seek segregation of wheeling and supply of electricity into distinct licensed activities.

The manner in which the DF contracts are devised, the same envisaged roles, and the revenue streams pertain to both wheeling as well as supply of electricity. With the proposed segregation of wheeling and supply licenses, it is important that creation of the reporting responsibility of the DFs and the mechanism for segregation of the revenues to be generated from the DFS between two licensees is achieved in a fair and balanced manner. It is recommended that the process for the same should be initiated at the earliest opportunity, championed by the MOP.

Review of Progress on Generation PPP

Following legal and regulatory changes in Indonesia with respect to the tax on the sale of coal at a benchmark price, several imported coal-based power generating stations approached the Central Electricity Regulatory Authority (CERC) for revision in tariffs in their power purchase agreements (PPAs) on grounds ranging from a change in law to force majeure. Ultimately, CERC, having considered these representations for Coastal Gujarat Power Ltd. (a subsidiary of Tata Power Company Ltd. that is operating the Mundra ultra mega power plant [UMPP] project), ruled in April 2013 that a package of compensatory tariff shall be determined by a committee and should be paid to the generating company over and above the tariffs in the PPA to restore viability to the projects. The committee's recommendation was considered by CERC, which then passed an order in February 2014 for implementation of revision in tariffs.³ Similar revisions were determined for the Adani Power Ltd. project that was supplying power under the Case 1 route to more than one state utility.

As observed previously, Coal India Ltd. (CIL) has since 2011 revised the New Coal Distribution Policy to reflect the shortage in supply of domestic coal for the thermal power projects commissioned over the 12th Five-Year Plan (2012–17). CIL's annual contracted quantities (ACQs) for fiscal year (FY) 2014 through FY2017 were thus set at 65 percent, 65 percent, 67 percent, and 75 percent, respectively, of the letter of assurance (LOA). This approach confers on successful bidders with domestic coal under Case 1 and Case 2 processes an uncovered obligation to supply power up to 85–90 percent availability without adequate coal linkage for the same. After consulting CERC, the MOP issued a clarification to CERC and state electricity regulatory commissions in July 2013 that the difference between the ACQ and the quantity in the LOA shall be allowed to be imported by CIL or by the generating station and allowed as a pass-through in tariffs under the PPA.

While these fuel-specific issues were being addressed, the MOP started deliberations on a new set of SBDs for Case 1 and Case 2, which were structured primarily on payment of energy charges on a predetermined basis with competition focused mostly on efficient construction and operation of the power plant. The new set of SBDs were notified on November 9, 2013, and were substantially

different from the earlier formulations, which had been in existence since 2007. Two UMPP projects—a captive mine-based power project in Sundargarh district of Odisha and an imported coal-based power project in Kanchipuram district of Tamil Nadu—are the first two projects being bid out under the new set of SBDs.

The following are some of the features of the new SBDs, that have been highlighted by prospective bidders, lenders, and utilities as being likely to pose challenges in implementation:

- Deviations from guidelines (including SBD) are permitted only with the permission of the central government (as opposed to the appropriate commission according to the earlier guidelines).
- Because the same documents have been circulated for case 1 and case 2, a two-stage process is the default for case 1 too and many provisions (such as selecting one successful bidder) shall need necessary modification to be used practically for case 1.
- No more than seven bidders are to be prequalified at the request-for-qualification stage. This provision is waived for UMPPs only, in which case all qualified bidders are short listed for the bid stage. Although this approach is acceptable for a case 2 process, several case 1 bid processes have resulted in multiple successful bidders at various quoted tariffs. Running a process with only seven qualified bidders can thus severely limit competition in case 1 procurement.
- Qualification criteria are not distinguished between case 1 and case 2 procurement processes. Elaborate technical qualification criteria are applicable for case 1 bidders, even though their generation projects may already be operational.
- A clause on change in law for imported projects now recognizes legal changes in the countries from which coal is imported.
- The SBD requires a fuel supply agreement to be signed for 25 years in favor of the utility, which is a highly unrealistic proposition because the longest coal supply agreements in the current market are for five years. This clause is likely to create issues particularly for imported coal-based projects, for which much shorter coal supply agreements are the market norm. An exception would be equity coal, that is, a coal supply agreement that is linked to a mine owned partly or fully by the plant sponsor, such as Tata Mundra's agreement with mining subsidiaries of Bumi Resources Tbk., of which Tata Power Company Ltd. has 30 percent ownership.
- Point of delivery is to be specified by the utility, and all quotes are for the point of delivery after factoring in auxiliary consumption and transmission losses.

- Incentives are allowed in the form of an increase in the fixed charge, if the actual station heat rate (SHR) outperforms the prespecified SHR in the RFP. So far, even for stations whose tariffs are determined by the regulator, SHR is a normative parameter for computation of energy charges and actual SHR is not measured or determined by a third party. The SBDs thus introduce a new obligation to determine SHR, which can lead to differences over the operating period of the PPA.
- Further, SHR is specified to be measured at the point of delivery, which is acceptable for case 2 projects but introduces an uncontrollable element of transmission losses for case 1 projects, and thereby adds a risk factor for the developer.
- For case 1 procurement, utilities have concluded that separate bid processes must be conducted for each type of fuel—domestic linkage coal, captive coal, imported coal, and so on.

Review of Progress on Transmission PPP

Since 2012, a few interstate projects and one intrastate transmission project have been awarded through the competitive bidding route. These are listed in table 8.4.

States have showed a general inclination for the Planning Commission model, because they are able to apply for central government financial assistance through viability gap funding (VGF) to the extent of 20 percent of the project cost, thus reducing the financial burden on the state government and end users. However, this isolated provisioning of VGF for only one segment of

Table 8.4 Interstate and Intrastate Transmission Projects Awarded through the Bidding Process, 2013

<i>Project</i>	<i>Successful bidder</i>	<i>Status</i>
<i>Interstate (MOP model—BOOM)</i>		
Kudgi Transmission Ltd.	L&T Infrastructure Development Projects Ltd.	SPV transferred
Vizag Transmission Ltd.	Power Grid Corporation of India Ltd.	SPV transferred
Purulia and Kharagpur Transmission Company Ltd.	Sterlite Grid Ltd.	SPV transferred
Patran Transmission Company Ltd.	Techno Electric and Engineering Company Ltd.	SPV transferred
RAPP Transmission Company Ltd.	Sterlite Grid Ltd.	SPV transferred
NRSS-XXXI (A) Transmission Ltd.	Power Grid Corporation of India Ltd.	LOI Issued
<i>Intrastate (PC model—DBFOT)</i>		
Satpura-Ashta 400 kV transmission line	Kalpataru Power Transmission Ltd.	LOI issued in April 2013

Source: Deloitte research, http://www.deloitte.com/view/en_BG/bg/insights/deloitte-research.

Note: BOOM = build-own-operate-manage; DBFOT = design-build-finance-operate-transfer; kV = kilovolt; LOI = letter of intent; MOP = Ministry of Power; PC = Planning Commission; SPV = special purpose vehicle.

the power sector value chain is an incongruity that the central government may need to reassess, especially because competitive bidding is the mandatory route for construction of transmission projects under the National Tariff Policy. The estimated expenditure on transmission projects under the 12th Five-Year Plan is Rs 1,800 billion (~US\$30 billion). If VGF is to be provided to all state-sector projects, the extent of central government assistance can be very high and needs to be carefully assessed. The use of VGF therefore raises doubts about the sustainability of supporting such large investments in a single power sector segment, where recovery of full costs through user (transmission) charges has not generally been a problem and thus the feasibility of such projects has not been much in doubt.

Since the framing of SBDs by both the MOP and the Planning Commission, a significant change in transmission charges and sharing methodology (point of connection [POC] charges) was implemented by the CERC for the interstate transmission system effective November 2011. The POC methodology determines transmission charges and losses based on connection nodes in the network and does not require the beneficiary to pay for individual elements or projects in the interconnected transmission system. This delinking of assets from beneficiaries requires a change in the counterparty to the transmission service agreement (TSA) entered into by the independent transmission service provider. The MOP has been working on revising its SBD to align itself with this changed regime, where the TSA will need to be entered into with Power Grid Corporation of India Ltd., which in turn will provide the service of collecting all POC charges and reimbursing private transmission developers for their share of transmission charges.

Notes

1. The Ministry of Power launched the R-APDRP in July 2008. This program, with a focus on establishment of baseline data, fixation of accountability, reduction of aggregate technical and commercial losses up to 15 percent through strengthening and up-gradation of the subtransmission and distribution network, and adoption of information technology (IT), will result in recommendations that shall be taken up in two parts. Part A shall include the projects for establishment of baseline data and IT applications for energy accounting and auditing and for IT-based consumer service centers. Part B shall include regular distribution-strengthening projects and will cover investments in system improvement, strengthening and augmentation, and so on.
2. For further detail, see http://www.powermin.nic.in/acts_notification/electricity_act2003/pdf/Draft_amendments_in_Electricity_Act_2003.pdf.
3. Procurer utilities have since filed appeals against this order with the Appellate Tribunal for Electricity. Rajasthan and Punjab filed by April 2014, and a few others were considering doing so shortly thereafter.

Reference

Government of India. 2012. *Report of the Task Force on Private Participation in Power Distribution*. Secretariat for Infrastructure, New Delhi. http://www.infrastructure.gov.in/pdf/Private_Participation_in_Power_%20Distribution.pdf.

APPENDIX A

Organization of the Power Sector in India

Electricity is under the jurisdiction of both the central (federal) and state (provincial) governments, that is, both governments have powers to legislate on the subject. Figure A.1 depicts the institutional structure at the central and state levels. At the central level, the Ministry of Power is responsible for the policy-related aspects of the sector and overall sector planning is entrusted to the Central Electricity Authority (CEA). However, the role of the CEA has been diluted over the past few years to the point where it now focuses mainly on the national grid and reviews of large hydropower project applications. The Central Electricity Regulatory Commission addresses the regulatory aspects of the sector involving more than one state. State electricity regulatory commissions address regulatory issues at the state level. In line with the philosophy of a national grid, the National Load Dispatch Centre and the regional load dispatch centers are envisaged as system operators in the national and regional networks, with each state housing a state load dispatch center. Figure A.2 shows the main entities in the power sector.

Figure A.1 Institutional Structure of the Electric Power Infrastructure

	At central level	At state level
Policy	• Ministry of Power	• State government
Planning	• Central Electricity Authority (CEA)	• State government
Regulations	• Central Electricity Regulatory Commission • Central Advisory Council	• State Electricity Regulatory Commission • State Advisory Council
System operations	• National Load Dispatch Centre (NLDC) • Regional Load Dispatch Centre (RLDC)	• State Load Dispatch Centre (SLDC)
Dispute resolution	• Appellate Tribunal	

Source: CRIS analysis.

Figure A.2 Key Players in the Electric Power Infrastructure Sector

	Generation	Transmission	Distribution
Central sector	• NTPC; NHPC • NPCIL	• PGCIL	
State sector	• State generating companies such as GSEC and Mahagenco	• State transmission utilities such as GETCO and MSETCL	• State distribution companies such as MSEDCL, UGVCL, and DHBVN
	• Integrated utilities, such as Kerala SEB and Bihar SEB, that are not yet unbundled under provisions of Electricity Act of 2003		
Private sector	• Large number of private generation companies such as Tata Power, Reliance Power Ltd., and Adani Power Ltd.	• Few JV companies: Tala Transmission Project, JSW–Maharashtra JV • IPTC such as Reliance Power Transmission Company	• Few players such as Tata Power, Torrent Power Ltd., and Reliance Power Ltd.
Traders: PTC India Ltd., Adani Power Ltd., JSW Steel Ltd., and Tata Power Trading Company Ltd.			

Note: DHBVN = Dakshin Haryana Bijli Vitran Nigam; GETCO = Gujarat Energy Transmission Corporation Limited; GSEC = Gujarat State Electricity Corporation Ltd.; IPTC = independent power transmission company; JV = joint venture; Mahagenco = Maharashtra State Power Generation Company Ltd.; MSEDCL = Maharashtra State Electricity Distribution Company Ltd.; MSETCL = Maharashtra State Electricity Transmission Company Ltd.; NHPC = National Hydroelectric Power Corporation; NPCIL = Nuclear Power Corporation of India Ltd.; NTPC = National Thermal Power Corporation; PGCIL = PowerGrid Company of India Ltd.; SEB = state electricity board; UGVCL = Uttar Gujarat Viji Company Ltd.

APPENDIX B

Dabhol–Enron: The First Lesson Learned under the New Independent Power Producer Policy

Table B.1 Dabhol Power Project: Timeline of Key Events

<i>Timeline</i>	<i>Dabhol power project—key events^a</i>
1991–92	India opens its power sector to private foreign investors.
February 1992	Enron Corporation begins investigating opportunities in the Indian power sector.
June 1992	Enron and General Electric (GE) sign a memorandum of understanding with the Maharashtra State Electricity Board (MSEB) to begin the Dabhol power project. The operating entity, Dabhol Power Company, forms as a joint venture with Enron (majority owner, 65 percent), MSEB (15 percent), GE (10 percent), and Bechtel Corporation (10 percent). A project capacity of 2,184 megawatts (MW) is envisaged in two phases of 740 MW and 1,444 MW, along with an integrated 5 million metric tonnes per annum liquefied natural gas (MMTPA LNG) terminal.
December 1993	Dabhol Power Company and MSEB sign a power purchase agreement (PPA).
1994–95	Enron obtains US\$635 million in financing, insurance, and loan guarantees from Bank of America, ABN AMRO Bank, a group of Indian banks, Export-Import Bank of the United States, and Overseas Private Investment Corporation (OPIC).
1995	A new government is voted to power in the state elections. Munde Committee is appointed to review the Dabhol power project. Maharashtra state government issues notice to end the project. Enron enters arbitration and seeks compensation. The state government files suit to void the agreement, alleging fraud and misrepresentation.
February 1996	The state and Dabhol Power Company agree to and finalize a revised agreement.
1997	Enron obtains approval from the central government to expand the Dabhol LNG terminal to allow it to process 5 MMTPA.
May 1999	Dabhol phase 1 (740 MW) begins generating power.
January 2001	The state stops payment to Dabhol power project on its December 2000 bill and subsequently seeks to cancel the PPA.

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Table B.1 Dabhol Power Project: Timeline of Key Events (continued)

<i>Timeline</i>	<i>Dabhol power project—key events^a</i>
April 2001	Enron begins arbitration proceedings.
May 2001	MSEB rescinds the PPA.
June 2001	Dabhol Power Company ceases operation of phase 1 and halts construction on phase 2 (1,444 MW), which is 90 percent complete.
December 2001	Enron files for bankruptcy in the United States under allegations of large-scale corporate fraud and corruption.
March 2002 ^b	Indian lenders move that the Bombay High Court appoint a court receiver. Punj Lloyd Ltd. is appointed as court receiver for undertaking the preservation of plant assets.
November 2004	Union Cabinet of India constitutes an Empowered Group of Ministers. The central government plans to revive the project. Restructuring framework is approved, and stakeholder negotiations begin.
July 2005	Settlements are reached between Indian and offshore stakeholders. Payments are made to foreign lenders, OPIC, GE, and Bechtel against release of all future claims.
July 8, 2005	Ratnagiri Gas and Power Private Ltd. (RGPPL) is incorporated with an equity contribution from the National Thermal Power Corporation (NTPC); GAIL Ltd.; and a group of financial institutions, including ICICI Bank, IDBI Bank, the State Bank of India, Canara Bank, Industrial Finance Corporation of India Ltd., and Gujarat Industries Power Company Ltd., to take over the project and complete its revival.
September 2005	RGPPL board approves an investment of Rs 10,303 billion for acquiring and reviving the assets of the former Dabhol power project. RGPPL and international finance institutions (IFIs) sign a common term loan agreement giving effect to a loan facility and to the equity contribution of promoters to acquire the assets of the project.
Present	Shareholding structure of RGPPL is as follows: NTPC (31.52 percent), GAIL (31.52 percent), IFIs (20.28 percent), and MSEB (16.68 percent). Dabhol power project's power blocks are fully revived and operational as a result of gas links from the Krishna-Godavari Basin. LNG terminal is undergoing investments in backwater infrastructure for revival.

Note: MSEB = Maharashtra State Electricity Board; MW = megawatt; NTPC = National Thermal Power Corporation; PPA = power purchase agreement.

a. Minority Staff Committee on Government Reform. 2002. "Fact Sheet: Background on Enron's Dabhol Power Project." U.S. House of Representatives, February 22, http://finance-mba.com/Dabhol_fact_sheet.pdf.

b. Deloitte research.

Summary Case Studies of Distribution Privatization

Highlights of the Orissa Reform Experience

Following an unsuccessful attempt at private participation through the management contract route in the central zone distribution company, the government of Orissa established the privatization program and simultaneously divested 51 percent ownership in its four distribution utilities in 1999. Whereas management control of three distribution companies (discoms) was transferred to the highest bidder, the transfer of the fourth discom (Central Electricity Supply Company, CESCO) proved unsuccessful after two rounds of bidding. Therefore, management control of the fourth discom was transferred to an international investor, AES Ltd., on a negotiated route.

The transfer of ownership in distribution and generation companies resulted in substantial monetary inflows for the government of Orissa. Because the state government concluded that the sector as a whole would improve under private ownership in distribution, the state stopped all forms of subsidy support to distribution companies.

But several unforeseen developments took place shortly after privatization in Orissa. In late 1999, a super cyclone (hurricane) caused substantial damage to the electrical network, especially in the CESCO areas. The state government maintained its position of not providing subsidy support to distribution companies. AES quit CESCO in 2001, and the distribution undertakings were subsequently transferred to the public sector again through the Central Electricity Supply Undertaking (CESU) in 2006.

In 2004, the Orissa Electricity Regulatory Commission had instituted a multiyear tariff regime, accepting actual starting loss levels in 2004 and setting more realistic targets of loss reduction over the first and second control periods. As a result, two of the discoms (Wesco and Nesco) are now close to break even with tariff increases also granted in 2011 and 2012. However, their efforts at reducing transmission and distribution losses, even after a decade and a half of private ownership, have been far below expectations. Rural electrification, which was

an unfinished agenda item at the start of privatization, has been completely neglected; more than half of households in Orissa still lack access to electricity. CESU and Southco continue to be the most inefficient discoms, requiring substantive focused efforts at improving efficiencies.

After Orissa's experience, many states adopted similar reform approaches at the end of the 1990s and early 2000s. Assam, Delhi, Gujarat, Haryana, Karnataka, Madhya Pradesh, Rajasthan, and Uttar Pradesh adopted state-level legislation to reform their power sectors. Delhi has succeeded in privatizing distribution under a performance-linked, benefit-sharing model.

Highlights of the Delhi Distribution Privatization Experience

To combat the worsening power situation it faced, the government of Delhi developed a Strategy Paper in 1999 that envisaged the following: (a) establishing a state-level regulatory commission, (b) unbundling the consolidated electricity company, Delhi Vidyut Board (DVB), (c) increasing disinvestment in the distribution segment, (d) implementing interim measures to improve the performance of the DVB, and (e) protecting staff members' interests.

The reform process continued with setting up and operationalizing the Delhi Electricity Regulatory Commission and appointing consultants to undertake the reforms process. A tripartite agreement was signed, ensuring no retrenchment of staff, no change in service conditions, continuity of service under DVB and the restructured entities, creation of a retirement benefits fund managed by a trust, continuation of welfare schemes, and an ad hoc pay increase of Rs 500 per month upon transfer to the new corporate entities.

Thereafter, in 2000, the Delhi Assembly proposed the Delhi Electricity Reform Bill that was finally passed as the Delhi Electricity Reform Act in 2001 (after presidential assent). The act furthered reform initiatives in the state and eventually resulted in privatization of the distribution segment. Six prospective bidders were prequalified, of which five were Indian and one was international (AES Corporation). To take the process forward, six shell companies (a holding company, a generating company, a transmission company, and three distribution companies) were registered. Those companies would become the successor entities upon operationalization of the transfer scheme. Thereafter, the government issued the transfer scheme rules leading to the opening balance sheets of the new entities and outlined the manner in which the assets and functions would be transferred to the new entities.

Unlike in Orissa, where the state sought to sell its stakes to the highest bidder, the Delhi privatization process recognized that loss reduction was the top priority and structured its bid variable accordingly. The Delhi bids, which were received on the basis of the aggregate technical and commercial loss reduction to be achieved postprivatization, were initially not acceptable to the Delhi government. Therefore, negotiations were held with the preferred bidders. In June 2002, the negotiations resulted in successful agreement on the loss reduction trajectory, execution of the shareholders' agreement, and other issues. The successor entities

finally became effective at midnight on June 30, 2002. The Brihanmumbai State Electricity Supply emerged as the preferred bidder for two discoms, and Tata Power for the third discom.

The Delhi experience has been the only example of electricity distribution privatization in India's postreform era. The stakeholders have benefited from the privatization exercise in the following manner:

- The Delhi government benefits from a reduced burden on the exchequer, and efficiency levels have improved and are now among the best in the country.
- Consumers receive a reliable and high-quality supply. There is significant difference in the customer service orientation, relative to the DVB days. For example, the number of payment centers has increased from about 20 to more than 5,000. Reliability of supply has improved dramatically. More than 40 percent of the workforce is new (old and aging DVB employees were offered an attractive voluntary retirement scheme), and capital investments have been consistently maintained, leading to substantial system strengthening.
- Barring a couple of years, the private utilities have not experienced losses and have been able to raise funds from the market to invest in the network and systems.

The Delhi experience has been unique because of the Delhi government's well-conceived plan that consisted of the following:

- Fixing achievable loss reduction and other improvement targets during the initial years of the transition period kept the focus on efficiency improvement alive during the entire process. Efficiency improvement and reduction in losses were considered the most significant measures for reducing the cost of supply to authorized customers, thus helping avoid tariff increases.
- The Delhi government's transition support, amounting to Rs 34.5 billion during the first five years of the existence of the private utilities, helped the private utilities avoid the cash crunch they would have otherwise faced during the initial years when the efficiency levels were extremely poor, as was the case in Orissa.
- Following an inclusive approach by bringing the regulator, government, and other key stakeholders together helped resolve issues that were likely to affect the success of the project during the transition period. Making the bid parameters binding on the Delhi Electricity Regulatory Authority for the purpose of tariff determination was among the key measures for building and ensuring investor confidence in the privatization process.

The key benefit for the Delhi government when it undertook electricity sector reforms was having the live example of Orissa, which demonstrated that the mere transfer of ownership to a private party was no guarantee for efficiency improvements and improved customer service levels. For success in any possible future distribution privatization initiatives with transfer of ownership that may ever be considered, one must understand the key differences between these two beacons in terms of the process followed and outcomes achieved.

Post-2012 Generation and Uncertainties Related to Domestic and Imported Fuel Supply

Despite the initial success of tendering more than 50,000 megawatts (MW) of projects under either case 1 or case 2, developments from the start of the 12th Five-Year Plan in April 2012 have revealed significant structural and policy issues that need to be addressed for the sector to move to predominantly private-led capacity additions. Our concluding comments on generation are related to the most pressing issue of fuel supply, in terms of not only domestic coal and imported coal, but also the indexation used by the Central Electricity Regulatory Commission (CERC). Apart from fuel supply, the other two red-flag issues identified (governance and liquidity risk) are also important, but we believe that fuel uncertainty is holding back private investment in the 12th Five-Year Plan (2012–17). Therefore, we focus on that issue.

Domestic Coal-Related Uncertainties

It has been proposed for consideration that the failure of Coal India Ltd. (CIL) to meet its fuel supply agreement (FSA) commitments could be solved by CIL purchasing coal for import and that the prices of such purchases should be eligible for pass-through in the FSAs as well as the associated power purchase agreements (PPAs). This proposal appears to be a workable solution, but only if the quantities of shortfalls are minimal and only in the nature of interim deficits.

Ultimately, projects that have been developed on the basis of domestic coal should obtain domestic coal, and separate projects should be planned on the basis of imported coal. Blending of coal, although feasible in theory, is not always technically feasible or economically the best choice, because it does not allow for efficiencies in procurement and use of imported coal. Depending on the physical condition and properties of the coal that is being blended, the combustion efficiency and carbon loss might be affected. In addition, the presence of trace

elements (such as mercury) could increase ash deposition, thereby affecting corrosion and precipitator performance.

After CIL failed to meet the March 31, 2012, deadline for signing FSAs, as set out in the directive issued by the Prime Minister's Office, the Ministry of Coal announced a presidential decree forcing CIL to guarantee long-term fuel supply, even if it has to import the coal. Accordingly, the CIL board approved the modified FSA applicable to thermal power stations commissioned between April 1, 2009, and December 31, 2011, as recommended by the Central Electricity Authority and the Ministry of Power. The FSA to be signed, with some 48 companies for 18,522-MW capacity mandates, contains a commitment to supply 80 percent of the coal requirement of each company. A token percentage of the basic value for the shortfall quantity has been specified, which would be effective three years after the date of signing the FSA. For a list of some projects facing fuel-related issues, see table D.1.

Table D.1 Selected Private Sector Generation Projects Facing Fuel-Related Issues

<i>Project</i>	<i>Developer</i>	<i>Fuel type</i>	<i>Status update/ COD</i>	<i>Issues</i>
Mundra UMPP	Tata Power	Imported coal	All five units have been commissioned	The regulatory changes in the pricing of Indonesian coal makes the product market linked, which poses critical challenges for imported fuel-based projects.
Krishnapatnam UMPP	Reliance Power Ltd.	Imported coal	Construction work stopped	Developers of projects that have already been bid are seeking rate revisions to ensure viability. CERC has granted rate revisions to a few projects; this has been challenged by procurers before the ATE.
Mundra Phase 1	Adani Power Ltd.	Imported coal	2009–10	
Mundra Phase 2	Adani Power Ltd.	Imported coal	2010–11	
Mundra Phase 3	Adani Power Ltd.	Imported coal	2010–11	
Ratnagiri	JSW Steel Ltd.	Imported coal	2010–11	
Mundra Phase 4	Adani Power Ltd.	Blended coal (domestic + imported)	2012–13	Fuel security issues have arisen from both domestic and imported fuel sources, because the domestic coal link lacks sufficient quantity and Indonesian coal prices have increased.
Mundra Phase 3	Adani Power Ltd.	Domestic coal	2012–13	Even after signing the FSA with GMDC to supply 4 MTPA of coal from Morga II block, supply of the committed quantity could not be ensured because the MOEF refused to permit mining in the blocks falling under the "no-go" area.
CLP Jhajjar	CLP India Private Ltd.	Domestic coal	2012–13	This is a case 2 project, which has continued to face coal supply shortages.
Tiroda Phase 3	Adani Power Ltd.	Domestic coal	2012–13	The MOEF withdrew terms of reference for mining in allocated Lohara block because of its proximity to a tiger reserve.
AES Chhattisgarh	AES Ltd.	Domestic coal	2016–17	The MOEF declared the allocated Sayang coal block a no-go area.
Mahan	Essar	Captive coal	2012–13	The MOEF declared Mahan coal block in Madhya Pradesh a no-go area.

Note: ATE = Appellate Tribunal for Electricity; CERC = Central Electricity Regulatory Commission; COD = commercial operation date; FSA = fuel supply agreement; GMDC = Gujarat Mineral Development Corporation Ltd.; MMTPA = million metric tonnes per annum; MOEF = Ministry of Environment and Forests; UMPP = ultra mega power plant.

Suggestions have been made that pending resolution of linkage and captive allocation issues, energy charges from case 1 projects should also be made a pass-through in tariffs. We believe that this suggestion is regressive and is an attempt to fix a default in commitment and performance by CIL through relaxations in the PPA—that is, an attempt to place the burden of CIL's shortcoming on the power customer. The only lasting solution is for all parties in the power sector value chain to honor their contractual commitments. Therefore, it is imperative for CIL to be more transparent and sign binding FSAs with developers, and these FSAs should have predetermined, serious penalties for defaults. (At present, the penalty has been set at a nominal level, which is unlikely to have any meaningful financial effect).

Imported Coal Uncertainties

There are two fundamental issues that have been raised by stakeholders with regard to the bidding framework adopted for competitive bidding of imported coal-based projects:

- Does the framework ensure that the least cost power is being procured at all times?
- Does the framework adequately compensate bidders for regulatory changes in the country from which the coal is being imported?

With regard to the first question, there have been concerns (voiced by procurers and auditors) about the efficacy of the competitive bidding framework because of the outcomes of the Mundra ultra mega power plant (UMPP) bid process and the current tariffs that the project is incurring. Comparing the bids of Tata Power and Adani Power Ltd. in Mundra UMPP, many people have noted that Adani's tariffs would have remained below Rs 3 per unit for long periods over the term of the PPA. In contrast, Tata Power's tariffs¹ have escalated significantly—45 percent of their energy charges are linked to international coal indexes, which have risen from around US\$50/ton at the bidding stage to the current level of US\$120/ton.

Although there could be merits in improving the indexations developed by CERC for both evaluation and payment, one should not compare the payment streams of two bidders for a year and then draw conclusions about the efficacy of the competitive bidding system. Assumption of all coal-related price variation risks by the bidder is not an ideal scenario and is rather impractical. Therefore, although Adani's bid (which assumed all coal-related price variation risks) would theoretically have yielded better results for the procurer at this point in time, one cannot determine how Adani could have made this project profitable with fixed coal-related compensation and in a scenario where substantial regulatory changes have raised the price of coal from Indonesia and Australia in particular. We already have the example of similar bidding practices in the Krishnapatnam UMPP, resulting in a project that is not proceeding.

On the issue of compensation in tariffs for unanticipated and fundamental regulatory changes in the country from which coal is being imported (that is, Indonesia), the following aspects must be considered:

- The effect of the regulatory changes is, undoubtedly, substantial, and the changes would have clearly been difficult for any bidder to anticipate. The most likely scenario is that none of the bidders factored these changes into their bids for the Mundra UMPP. Tata Power (the winning bidder) has argued that regulatory changes should be considered as a force majeure incident, given the bidders' lack of control over such an eventuality and given those changes' critical relevance to the project. This argument is made even though the PPA did not provide for any political force majeure for regulatory or policy changes outside India. Although the circumstances in which Tata Power finds itself are unfortunate, Tata Power may be able to successfully claim the regulatory changes as a force majeure incident under the agreement. A preferable approach may be for the government of India/CERC to mediate and work with both Tata Power and the concerned distribution companies to reach a mutual agreement on revisions to the PPA.
- Conceivably, the effect of these regulatory changes will be reflected in future contracts and should be factored into the benchmark price index for Indonesian coal. If bidders had a substantial part of their bid in the escalable component, with adequate incorporation of discounts to benchmark prices (because of a long-term contract with preferential sale prices), they would be hedged against such risks.
- In revisions to the standard bidding documents, a fundamental change in law in countries from which coal is being imported should be allowed in the PPA.

Improvement in CERC Indexation

The escalation rates approved by the CERC for imported coal are determined today using API4 (price of South African coal) for short-term data series. Almost 60–70 percent of the fuel contracts are long-term contracts on which these escalation rates (based on short-term data) are applied. Major fuel imports in India are mostly from Indonesia, followed by Australia. The current indexation does not incorporate price fluctuations or indexes for import from these countries, and this would appear to be a major problem area.

Given the large quantum of coal imports required for large-sized thermal power units planned under supercritical technology in India, it makes sense to provide tailor-made indexes for each country of import rather than arriving at a composite index. PPAs could then recognize the primary country of import and allow country-specific price indexation. This adjustment would closely reflect the underlying pricing structure in the long-term coal supply agreements and would remove any index-related uncovered risks for bidders.

Note

1. According to the tariff-based competitive bidding guidelines, the bidders can quote separate escalable and nonescalable components of tariff (capacity charge and energy charge) as explained in chapter 2. Payment of the escalable components over the term of the PPA is based on payment indexes that CERC revises semiannually. Nonescalable components are paid as quoted for the contract year without any adjustments.

Emerging Challenges for Private Investment in Transmission

Issues and Challenges for Private Transmission Line Developers

Although private participation has been observed across all 15 projects that have been offered under competitive bidding, a few inherent challenges have now surfaced and have been acknowledged by all players in this segment (table E.1).

Experience in Private Projects Being Implemented versus the Transmission Framework

The biggest advantage that private players eventually bring is efficient project execution capabilities. However, the experience of private participation in the transmission space in India is too brief to conclude how successful the players have been in executing projects efficiently. The following observations can be made on inputs obtained from several developers that were contacted as part of this study.

The initial optimism in private transmission that attracted a very broad base of players from divergent segments now appears to converge to a set of players who have requisite project management capabilities. This is reconfirmed from the recent bidding for the Nagapattinam–Cuddalore (450-kilometer, 765-kilovolt transmission lines) project for which 18 bidders showed initial interest but only five finally bid for the project. Private players are now realizing the virtues of undertaking detailed project cost estimation with a higher degree of prudence.

For most of the projects bid out, there continues to be a very wide range in the bids submitted. This variation indicates a wide divergence in the risk perception of developers and in their estimation of project costs. For example, in the recent Nagapattinam–Cuddalore project, the bid of PowerGrid Company of India Ltd. (PGCIL), which emerged as the winner, was just around 66 percent of the next bidder. This difference can be attributed to PGCIL's eagerness to establish itself through competitive bid out projects, its experience in implementing transmission lines, and its ability to appreciate and handle project-related

Table E.1 Risks for Private Transmission Line Developers

<i>Risk</i>	<i>Particulars</i>
Financial closure	With fuel issues affecting certain generation projects, transmission projects that are linked to evacuation of power from such generation projects are viewed as risky and have been affected.
Payment default	<p>With the onset of the point-of-connection regime, a structural change has occurred in the modalities of transmission charges and routing to the transmission service provider.</p> <p>Point-of-connection regime provides for generation companies that have not identified their procurers to be beneficiaries under the transmission service agreement and take on obligations for payment of transmission charges.</p> <p>Although the PowerGrid Company of India Ltd. (PGCIL) obtains a deposit from all private generation players as part of the application process for connection to the interstate grid, this security is not available to transmission service providers.</p> <p>Private players bidding for transmission projects have asked for enhancement in the security obtained by PGCIL and for the ability to pass this on to the transmission service provider in case of defaults in timely execution of generation projects by the private developer.</p>
Approvals	Private developers are responsible for obtaining all approvals and clearance related to the projects. Because transmission projects transverse long distances, each tower location could be considered as one specific project (specifically in the Indian context). Furthermore, forest clearances take long periods of time, and any delay in approval leads to cost escalation.
Right of way	<p>Transmission lines themselves do not need any land acquisition. However, they require that a right of way be obtained for constructing and laying the towers. According to the Indian Telegraph Act of 1885, only crop compensation is to be paid to the farmers for a right of way and no additional payouts are envisaged. In practice though, obtaining a right of way involves not just crop compensation but also additional payments to the landowners to enlist their cooperation in ensuring that the towers are installed in time.</p> <p>For almost all developers, the cost attached to obtaining a right of way is impossible to estimate accurately and varies widely depending on the negotiations at the local level.</p>
Cost escalation	<p>Cost escalation is not a pass-through for private developers of transmission projects. This is always a concern because most projects could incur increased costs because of delays on account of lack of rights of way for laying the transmission towers.</p> <p>Transmission projects are structured under a competitive tariff-bidding route. Bidders are entitled to an agreed tariff over the period of the projects. At the time of bid submission, the bidders assume certain levels of capital expenditure. However, there are high probabilities of cost escalation owing to delays in multiple approvals related to the projects. In addition, volatilities in the cost of input materials cannot be predicted with precision. The bidder therefore must be prepared to bear escalation in the project cost. The bidding framework does not provide for any cost pass-through—in fact, the bidding framework does not require any disclosure of project cost assumed by the developer.</p>

risks confidently. PGCIL's understanding of the transmission business is its definitive strength. For most of the regions where new extra-high voltage transmission lines are being proposed, PGCIL has existing operating lines. This provides PGCIL with an understanding of the topography and a better grasp of the implementation challenges that are prevalent in the area.

The Way Forward

Private participation in the transmission space will not stand on its own and must be viewed under the overall boundary of underlying generation projects to which it is proposed to be dedicated. In the Indian context, there are no concerns as such with regard to the public-private partnership framework under which transmission projects are envisaged. The concerns largely emanate from the perceived fate of the generation projects for the transmission projects that are proposed. For instance, the recent bidding for the Nagapattinam–Madhugiri interstate transmission lines had attracted many players when the bidding documents had been floated. However, at the time of bidding only a handful participated. Discussions with a few of the participants have indicated that most of them *perceived risks concerning the commissioning of the underlying generation assets*.

Competitive bidding for transmission projects is now the default mode for project execution at both the interstate and intrastate levels. There are experiences in the course of implementing projects that are worth considering for undertaking improvements in the existing framework. These aspects are evaluated, and a way forward and a possible recommended approach around them are provided in table E.2.

Table E.2 Evaluations and Recommended Approaches

<i>Area</i>	<i>Approach</i>
Models	<p>Two models are currently considered for engaging private players in the transmission space. The MOP has created a set of standard bidding documents that are derived from tariff-based competitive bidding framework. The Planning Commission has also produced a framework that stems from a model built around bidding for grants based on pre-determined tariffs.</p> <p>The sector cannot afford to have dissimilar models of project development, particularly in transmission, which needs to move harmoniously toward a unified structure with universal application of the point-of-connection regime.</p> <p>The process outlined under the Planning Commission framework was not in conformity with Section 63 of the Electricity Act of 2003, which required guidelines to be issued by the central government, in this case the MOP. In 2012, the MOP clarified that the Planning Commission framework could be adopted for intrastate projects under the guidelines issued by the MOP. Elements of the Planning Commission model that are superior should be included in the standard bidding document issued by the MOP, and only one model should be available for implementation of tariff-based competitive bidding in the sector.</p>
Distributed ownership and implications on grid operations	<p>Although PGCIL and the STU are currently responsible for the overall interstate and intrastate grids, a very dispersed ownership of elements of the grid will pose inevitable issues around interfacing and communication, which are not insurmountable but would require strict standards and protocols under the Grid Code to be adhered to by all owners of transmission assets for an integrated operation of the grid. Grid codes are being progressively implemented by the SERCs. Section 86(1)(h) of the Electricity Act of 2003 provides that SERCs shall specify state grid codes that shall be consistent with the Grid Code formed by the CERC. For higher voltage levels, the SERCs mostly adopt the Grid Code promulgated by the CERC.</p> <p>We believe the STUs and CTU will have a larger role to play in ensuring that the capacity of private developers is built to adhere to grid-based protocols.</p>

table continues next page

Table E.2 Evaluations and Recommended Approaches (continued)

<i>Area</i>	<i>Approach</i>
State support agreement	<p>Competitive guidelines consider project development–related risks to be best assumed by the developer and are accordingly passed on to the successful bidder. This creates an obvious challenge for the project developer in terms of obtaining statutory approvals and clearances, and so on, which are widely dispersed and numerous for transmission projects. We observe that for most projects developed under the joint venture route with PGCIL, PGCIL that has been responsible for all clearances and approvals. As a public sector body, PGCIL is well positioned to handle such aspects that by nature do not come easily to private sector players.</p> <p>A mechanism for state support should be formulated with obligations by the state governments to support private players in obtaining all clearances and approvals so that the private players could continue to focus on more important aspects related to design, engineering, and execution. The continued role of the STUs and CTU in obtaining clearances and approvals is critical and should go beyond extending letters of support, as currently envisaged under the TSA.</p>
Generation beneficiaries	<p>Bidders are highly uncomfortable in accepting generation companies as signatories to a TSA and being responsible for payment of transmission charges.</p> <p>Adequate safeguards should be built into the TSA and the security collected by PGCIL from such generators enhanced to cover against risk of defaults in payment of transmission charges. However, there has been no instance of any commissioned transmission project under the IPTC route. Therefore, the possibility of any default on this account has not been observed under this structure.</p>
Parity among bidders	<p>Private players consider PGCIL to have an advantage over them. This view is strengthened on account of the following aspects:</p> <ul style="list-style-type: none"> • PGCIL sits on the empowered committee that determines the projects to be bid out. Further, PGCIL is also a bidder for such projects. • PGCIL as a public sector undertaking has an edge when obtaining a right of way for transmission lines. Historically, for all lines owned by PGCIL, the onus for obtaining a right of way lies with PGCIL. • There is a likelihood that PGCIL may already be operating another line in the region where the new project being bid is considered for implementation. <p>State support framework could be a way to create parity between the private players and PGCIL.</p>
Access to information	<p>Many parties acknowledge that there is scope for improving the depth of information that is provided to bidders. Information in general is considered wanting in the areas of topographical details, detailing of forest areas, existing natural hazards in the vicinity, and existing built structures in the vicinity.</p> <p>A standard template taking stock of the information that needs to be detailed while inviting bids for a project could be created. The survey report provided by the central bid process coordinators has been observed to be of poor quality and is rarely relied upon by serious bidders who must undertake their own surveys. Importantly, the survey reports should also elaborate on implementation risks emanating from the topography of the tentative route considered in the reports.</p>

Note: CERC = Central Electricity Regulatory Commission; CTU = central transmission utility; IPTC = independent power transmission company; MOP = Ministry of Power; PGCIL = PowerGrid Company of India Ltd.; SERC = state electricity regulatory commission; STU = state transmission utility; TSA = transmission service agreement.

Comparison of Privatization to the Distribution Franchisee Approach

Privatization versus Distribution Franchisee

Although the urban input-based distribution franchisee (DF) experience has clearly shown value in terms of acceptance by stakeholders and outcomes, concluding that it is better than complete privatization of distribution licensees would be premature. A comparison of the urban DF framework with complete privatization is shown in table F.1 to identify the key differences and similarities that could form the basis for improving either of the models in future transactions.

An evaluation of the past cases of privatization and distribution franchising experiences reveals that the key reason for greater acceptance of the DF framework is its relative acceptance by the employees of the existing government-owned licensees compared with outright privatization. The privatization model offers several advantages over the DF model that may appear more important going forward. First, the private licensees operating under a perpetual license are in a much better position to introduce new and state-of-the-art technologies in the distribution and customer care infrastructure that may not appear appropriate to a DF because of the longer payback period for such investments. Several capital-intensive works could be beneficial from a customer service perspective, but may not have any tangible benefits for the franchisee, particularly closer to the end of the DF term. Second, with the primary responsibility for power procurement still resting with the licensee, the responsibility and the ability of the franchisee to make affordable and continuous power available to the ultimate consumers are limited to a substantial extent.

Additionally, the urban DF framework appears to be tailored to suit high loss (aggregate technical and commercial loss), creating areas where the franchisee pays an input rate to the licensee for the amount of energy input into the area, thereby leaving enough margin for itself to incur capital expenses and operation and maintenance (O&M) expenses and earn a profit. The very essence of the franchisee model—the concept of funding the loss reduction

Table F.1 Privatization versus Distribution Franchisee

<i>Parameters</i>	<i>Privatization</i>	<i>Distribution franchisee</i>
Term of agreement	The term is perpetual.	Fixed terms are typically for 10, 15, and 20 years.
Choice of area	If existing area of distribution company is not preferred by bidders, substantial efforts must be made in getting a transfer scheme approved for reorganization into a separate distribution company with the preferred configuration.	Configuring any potential area into a proposed area for franchisees is easy and flexible.
Ownership transfer	Equity participation of 51 percent or more is required.	No equity participation in licensee is needed.
Responsibility	All responsibilities are the same as those for a distribution licensee.	Power purchase (for additional procurement only) Capital expenditure Operation and maintenance All revenue cycle activities Customer care
Regulatory recognition	Private licensee is answerable to the regulator (SERC).	Franchisee is answerable only to the licensee
Ability to terminate in events of default	No such provision has been seen in past cases.	Licensee is free to terminate DF contract for DF events of default.
Binding efficiency improvement targets on private player	Binding targets, as in the case of Delhi privatization, may be agreed at the transaction stage itself.	Licensee sets targets at the transaction stage. Licensee is isolated from the actual efficiency levels once the input rate is determined through the competitive bidding process
Employee care	Existing employees are transferred to private licensee. Option for VRS may also be given.	Employees have the option to work for the franchisee or to remain with the licensee.

Note: DF = distribution franchisee; SERC = state electricity regulatory commission; VRS = voluntary retirement scheme.

related capital expenditure through additional revenues generated by effective and rapid loss reduction initiatives—would no longer be valid if there were significant loss reductions to be achieved. Also, as has been seen in the case of rural areas where the retail tariffs are primarily cross-subsidized at the utility level, revenue recovery from the retail tariff for select or identified rural areas by the franchisee may not be sufficient for incurring capital and O&M expenses under the existing DF model, thus leaving such areas unattractive to prospective bidders.

Privatization of distribution business in select areas may hold the key to attracting private sector efficiencies in the distribution segment on a sustained and long-term basis and will need to be weighed against the franchisee mode. Clear insights from the Orissa and Delhi privatization experiences point toward the prerequisites and pitfalls in distribution privatizations in the country. Mere change in ownership is not a guarantee for efficiency improvements, and the privatization approach therefore needs to align the expectations of the state government, the regulatory commission, and the bidders. The Delhi model is clearly a step forward over the Orissa experience, but if privatization were to be

considered by a state government, the following additional issues may need to be considered in future transactions:

- Clear, long-term efficiency-level targets may be incorporated into the bidding process itself, which could be agreed upon or approved by the concerned regulator as part of the multiyear tariff regulations for the utility.
- Desired outcomes in terms of customer service–related parameters, such as availability and reliability of supply, and so on, may be made mandatory on the licensee. The same requirements may be over and above the standards of performance mandated by the concerned regulator.
- Minimum capital expenditure for specified periods may be mandated as has been done in DF bids.
- To keep a check on the retail tariffs, the government (bidding authority) may put specific limits or conditions on the controllable cost parameters.
- The government (bidding authority) should have an option to terminate or cancel the appointment of the selected private player at any stage going forward in the event of clear default of conditions mandated at the bidding stage.

Recommendations for the Way Forward on Distribution Franchisee Selection

Table G.1 Recommended Approaches on Distribution Franchisee Selection

<i>Clause or aspect</i>	<i>Recommended approach^a</i>
Selection for urban franchisee area	<p>On the basis of a review of past experiences, the following desirable or mandatory attributes may be considered for identifying or short-listing suitable areas for implementing the distribution franchisee (DF) framework:</p> <ul style="list-style-type: none"> • The minimum size of the area, in terms of energy input, should be set to make the opportunity sizable and attractive for the desired set of potential investors. • An area with a high level of losses, a dense load base, and a subsidizing consumer base would make franchising an attractive proposition for the utility as well as the prospective bidders.
Term of the agreement	<p>A longer time frame helps the franchisee undertake capital-intensive investments in the distribution system that may have longer payback periods but are in the interest of the reliability of the network and the quality of supply.</p> <p>Ideally, DFs should have a minimum term of 15 years.</p>
Prequalification criteria	<p>An important parameter that needs to be considered when fixing the prequalification criteria for appointment of DFs is found in the sixth proviso of Section 14 of the Electricity Act of 2003: the conditions for eligibility for grant of a distribution franchise should not normally be more onerous than the conditions for grant of a second distribution license, specifically in terms of capital adequacy, credit worthiness, and code of conduct. Although the prequalification criteria are standardized, they may still vary from case to case, which can be linked to the existing revenue size of the area or other parameters.</p> <p>In view of the limited number of players in power distribution and the successful precedence in the power generation, telecom, and banking and insurance sectors, any prospective bidder who meets the following criteria should be allowed to participate:</p> <ul style="list-style-type: none"> • A company registered under the 1956 Companies Act • Experience in the power and allied sectors (the same may be defined appropriately) • Experience in handling labor (linked to size of the area in personnel and number of consumers) • Turnover equivalent to 75 percent of the gross annual revenue of the franchise area • Net worth of 25 percent of annual revenue of franchisee area • Positive Profit After Tax in any two of past three years of audited annual accounts

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Table G.1 Recommended Approaches on Distribution Franchisee Selection (continued)

<i>Clause or aspect</i>	<i>Recommended approach^a</i>
Consortium	<p>Allowing a consortium is in the interest of attracting (and offering a route for entry to) new players who have the financial capability but do not have the technical experience in the power sector and therefore intend to acquire a partner who can complement the same. The following may be adopted in this context:</p> <ul style="list-style-type: none"> • As a safeguard, the utility mandates incorporation of a special purpose vehicle (SPV) within a certain time frame (such as 45 days within issuance of letter of award). • The technically qualified partner should not have less than a 26 percent share in the SPV. • No more than three entities should be allowed to enter into a consortium. • There should be a lock-in period of at least five years in the proposed shareholding of the technically qualified partner in the SPV.
Preparatory activity— information availability for bidding	<p>To build investor confidence, reliable baseline data must be provided, such as the following:</p> <ul style="list-style-type: none"> • Provide five-year historical data on billing and recovery-related information, energy input, network infrastructure, and so on and the details of the latest ongoing contracts or works in the request for proposal (RFP) to be issued and the data room to be created for potential bidders. • A third-party audit of the commercial and technical data for the last or base year, including key items such as sales, revenue collections, and energy input, completed prior to issuance of the RFP may be recommended.
Input rate and implied loss reduction trajectory	<p>The competitive bidding process for a DF is designed for selecting the bidder who considers a pass-through of the maximum possible efficiency improvements and loss reduction in the franchisee areas in the input rate to be quoted for the area. The following may be included in the guidelines or standard bidding document (SBD) in this context:</p> <ul style="list-style-type: none"> • A reasonable and achievable aggregate technical and commercial (AT&C) loss reduction trajectory may be provided for in the RFP or distribution franchisee agreement (DFA). However, there is no separate need for any additional incentive or disincentive to be added for the achievement or non-achievement of the loss reduction because the franchisee shall be making the payments to the licensee as per the quoted rates and therefore the same is implicit. • To prevent front loading and to get a more even tariff structure, there can be a minimum mandatory ratio of 0.7 between the minimum tariff and the maximum tariff that the franchisee can quote for any particular year. This is in line with SBD in transmission and generation. • In terms of minimum benchmark rate, there could be a minimum expected rate to be quoted by the franchisee in any year. The same can be arrived at by evaluating the level of recoveries in the base year after duly adjusting for the potential savings in terms of the avoided costs after appointment of the franchisee. Specifying yearly benchmark rates or reserve prices limits the franchisees' flexibility and enhances the risk perception of bidders.
Input rate revision	<p>There could be a change in average tariff owing to a change in sales mix, consumption pattern, or any tariff revisions by the concerned state electricity regulatory commission (SERC). The input rate to be quoted by the franchisee for each year of the franchisee period may be adjusted on a monthly basis to ensure that risks and benefits are appropriately shared between the licensee and the franchisee:</p> <p>Indexed input rate for a month = (Quoted rate for the year) × (Average tariff for the month)/ Average tariff for the base year</p>

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Table G.1 Recommended Approaches on Distribution Franchisee Selection (continued)

<i>Clause or aspect</i>	<i>Recommended approach^a</i>
Availability of power supply	<p>Whereas most utilities commit to a minimum level of energy input for the entire period of the contract, no commitment is given on any future increase in availability. The franchisee and investors need to be assured that no discrimination will occur in making energy available for sale within the franchisee area going forward. The following may be included in the standard guidelines and SBD in this regard:</p> <ul style="list-style-type: none"> • There should be no reduction in energy availability to the franchisee below the base level that can also be called the minimum committed level. • The licensee should make available increased energy input to the franchisee at least in the ratio of the increase in supply taking place for the licensee itself on a year-on-year basis. • The licensee should not discriminate in the supply of electricity between the franchisee area and other similar areas under its license area. • In the event that the licensee is unable to meet the entire demand of the franchisee, the franchisee shall be allowed to purchase power from external sources (under a tripartite arrangement with the licensee) and fully recover for it in the form of reliability charges or any other charge as may be approved by the respective SERC.
Treatment of tax, duties, and levies	<p>The following may be considered in the SBD with respect to duties, taxes, and levies:</p> <ul style="list-style-type: none"> • The input rate quoted by the franchisee should be exclusive of electricity duty; tax on sale of electricity; municipal taxes; and other taxes, duties, levies, and so on that may be levied by the state government from time to time. • The franchisee shall pass on the taxes, duties, and levies to the utility on a collected basis. • Any new ruling from the state or central government on taxation (other than corporate income tax) or introduction of new tax shall be borne by the utility.
Treatment of subsidy	<p>The licensee receives a subsidy directly from the state government even for the power sold in the franchisee area. In areas where a bulk of the revenues comes in the form of government subsidies, the activities of the franchisees may not be a viable proposition in the absence of a pass-through of the subsidy being received from the state government. The following may be considered in the SBD in this context:</p> <ul style="list-style-type: none"> • The input rate to be quoted by the franchisee should be exclusive of tariff subsidy. • A subsidy may be retained by the licensee in areas where such revenue forms less than 25 percent of the total revenues for the licensee in the base year. • A subsidy may be passed through to a franchisee in areas where such revenue forms more than 25 percent of the total revenues for the licensee in the base year.
Capital investment	<p>Although it is essential that the franchisee have independence in undertaking capital investments in the franchisee area, the approach may be subject to the following:</p> <ul style="list-style-type: none"> • First, a minimum capital expenditure (capex) may be specified during the initial years of the franchisee period to ensure that the investments are lop sided in the initial years. The same is essential in view of the intense loss reduction initiatives to be undertaken by the franchisee. Second, most of the investments made during the initial years would be largely depreciated by the end of the franchisee period, thus having minimal effect on the licensee when transferred at book value. • If the franchisee intends to undertake any underfunded works or subsidized government schemes, the utility shall help by acting as an intermediary and passing on all costs and benefits to the franchisees. The franchisee may be required to maintain a Bank Guarantee equivalent to the loan outstanding in the name of the licensee as security for undertaking such assistance. • There should be a provision for regulatory approval of the capex during the last five years of the franchisee period, excluding the capital investment requirements for adding any new consumer to the network or those that are necessary to maintain continuity of supply.

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Table G.1 Recommended Approaches on Distribution Franchisee Selection (continued)

Clause or aspect	Recommended approach ^a												
Incentive of arrears	<p>Different utilities have followed varied approaches toward treatment of collections against arrears pertaining to the licensee period of supply by the franchisee. Selling out the entire value of the arrears upfront has occurred, as in the case of the recent bids in Madhya Pradesh, in the absence of detailed and reliable data. Where arrears baselines are reliable, a percentage of the arrears collected by the franchisee may be allowed to be retained by it as an incentive. The following incentive mechanism may be adopted in the SBD:</p> <table border="1" style="margin-left: auto; margin-right: auto;"> <thead> <tr> <th></th> <th style="text-align: center;"><i>Within 1st two years from effective date</i></th> <th style="text-align: center;"><i>From 3rd year to 5th year from effective date</i></th> <th style="text-align: center;"><i>After 5th year from effective date</i></th> </tr> </thead> <tbody> <tr> <td>Connected consumer (%)</td> <td style="text-align: center;">20</td> <td style="text-align: center;">17</td> <td style="text-align: center;">14</td> </tr> <tr> <td>Disconnected consumer (%)</td> <td style="text-align: center;">30</td> <td style="text-align: center;">27</td> <td style="text-align: center;">24</td> </tr> </tbody> </table>		<i>Within 1st two years from effective date</i>	<i>From 3rd year to 5th year from effective date</i>	<i>After 5th year from effective date</i>	Connected consumer (%)	20	17	14	Disconnected consumer (%)	30	27	24
	<i>Within 1st two years from effective date</i>	<i>From 3rd year to 5th year from effective date</i>	<i>After 5th year from effective date</i>										
Connected consumer (%)	20	17	14										
Disconnected consumer (%)	30	27	24										
Relationship with regulator	The regulator needs to develop a mechanism for approval of reliability charges for recovery of any additional or external power purchase that may be undertaken by the franchisee. Also, the regulator's involvement in overseeing the process for appointment of entry into a franchising arrangement will need to be expanded as the utilities increasingly begin to appoint DFs.												
Treatment of employees	<p>Treatment of employees is among the most critical issues with regard to a DF to ensure smooth implementation of franchisee arrangements by utilities. The following may be adopted in the guidelines and SBD:</p> <ul style="list-style-type: none"> • During the first three months from the effective date, the distribution licensee should provide diligent support to the franchisee for which the franchisee shall bear the cost of salary and allowances payable to the licensee's employees involved therein. • Thereafter, the franchisee shall have an option to take the licensee's employees on deputation. On the request of the franchisee, the licensee shall make available such number of its employees from the franchisee area who are willing to work with the franchisee, for such further period as considered appropriate, on a deemed deputation basis as per the terms and conditions of deputation applicable to the employees of the DF. • During the deputation period, the entire cost of employees shall be paid directly by the licensee to the licensee's employees and the same shall be reimbursed by the franchisee on the last business day of every month. • Employees on deemed deputation with the franchisee should have an option to revert back to the licensee at any time on giving one month's notice to the franchisee. In case the services of the licensee's employees working with the franchisee are required by the licensee, it shall also have the right to recall those employees prior to the completion of the deputation period by serving one month's notice to the franchisee. 												
Treatment of existing contracts	<p>The utility might have entered into various contracts for capital works in the franchised area, which may be ongoing or awarded at the point of handover of the area to the franchisee. The following may be considered in the SBD and guidelines in this context:</p> <ul style="list-style-type: none"> • With respect to ongoing or awarded capital works, the utility may continue with the project, complete it per schedule, and hand over such assets to the franchisee for routine operation and maintenance (O&M). In case the works proposed are critical to the success of the franchisee and the franchisee is not satisfied with the progress of the contractor appointed by the licensee, the franchisee may have the works cancelled by the licensee after due justification or explanation to the satisfaction of the licensee and may undertake such works itself at the budget or value approved by the licensee. In such cases, the franchisee shall bear the cancellation cost of such contracts, if any. • In the case of O&M contracts awarded by the licensee, the contracts shall be transferred to the franchisee. The franchisee shall be free to continue with or cancel such contracts at its will. The penalties or costs arising out of cancellation of such contracts should be borne by the licensee. • At the bid stage, the licensee should provide to the prospective bidders all details of capital works and O&M-related contracts entered into by it with various parties for the franchisee area. The contracts shall be made available to the franchisee in the data room. 												

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Table G.1 Recommended Approaches on Distribution Franchisee Selection (continued)

Clause or aspect	Recommended approach ^a
Audits and inspection	<p>Auditing of critical parameters important to the commercial interest of the licensee and the franchisee during the period of the contract is essential for maintaining transparency and avoiding any possibility of a potential conflict between the two parties. In this respect, a third-party audit of the following may be considered:</p> <ul style="list-style-type: none"> • One-time audit at the commencement of franchisee operations: <ul style="list-style-type: none"> – Utility assets being handed over to the franchisee – Opening level of arrears – Inventory and spares being handed over to the franchisee – Energy input, sales, losses, and base year average billing rate • Routine or periodic audit during the franchisee period: <ul style="list-style-type: none"> – Average billing rate on an annual basis – Subsidy booked or claimed, as applicable on an annual basis – Audit of asset register through field verification and validations on an annual basis
Commercial and management information systems and compatibility of information technology (IT) systems	<p>Licensees should aim at developing comprehensive IT-based franchisee monitoring systems that will interface with the franchisee's systems and provide periodic and online reporting access to the licensee. Such systems may generate performance reports, exceptions lists, flagging of critical issues, and so on.</p> <p>The DFA may contain such clauses that would enable the licensee to interface with the franchisee's systems. The DFA shall mandate that the IT systems and tools (especially those pertaining to consumer billing and complaint management) being developed by the franchisee are compatible with the IT systems of the licensee and could be interfaced as needed. Sharing of master data with respect to the revenue cycle should be made mandatory in the DFA and strictly enforced.</p>
Performance security	<p>For performance security, an unconditional, irrevocable, revolving letter of credit (LC) from a scheduled commercial bank (endorsed by Reserve Bank of India) for an amount equivalent to two months' estimated revenue billed should be recommended for DFAs in place of conventional bank guarantees. The value of such LC may be revised on a yearly basis to adjust for any changes in the value of the two-month billing base.</p>

a. Subsequent to the study, the Ministry of Power issued standard bidding documents for appointment of distribution franchisees. A comparison of the recommendations provided in this section and the standard bidding document is provided in chapter 8.

Standardization of the Distribution Franchise Process

The success of the Bhiwandi franchisee, in terms of both the steep loss reduction achieved by Torrent Power Ltd. and the improvement in quality and reliability of supply under the franchisee model, has encouraged several utilities and states to undertake such initiatives in areas where the licensees have been struggling to improve efficiency levels (see box H.1). The distribution franchisee (DF) model has evolved since the Bhiwandi model was implemented with only the key terms of the distribution franchisee agreement (DFA) on hand at the stage of bidding.

In several cases, utilities across states have failed to appoint DFs for two primary reasons. The first and most important reason has been the inconsistency in approach toward balancing stakeholder interests in the terms and conditions of the DFAs that are being tailor made by the states and state utilities on a case-by-case basis. The second reason is the lack of availability of quality baseline data and measurement systems for undertaking such transactions.

The DF under the present model is more like a management and outsourcing contract. The ultimate responsibility for the area still remains with the licensee. Also, the competitive bidding process by the franchisee affects only the efficiency levels and recovery of the licensee, which continues to file its annual revenue

Box H.1 Bhiwandi Distribution Franchisee: A Success Story

- On January 26, 2012 Torrent Power Ltd.–run Bhiwandi distribution franchisee (DF) completed its five years of operations.
- Bhiwandi DF, based on an input-based DF agreement with Maharashtra State Electricity Distribution Company Ltd. for a period of 10 years, is responsible for metering, billing, collection of revenues, and capital expenditure (capex).

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Box H.1 Bhiwandi Distribution Franchisee: A Success Story *(continued)*

- Capital expenditure is subjected to regulatory approval and jointly verified by distribution company and franchisee.
- Torrent Power Ltd. is able to aggressively reduce the gap between average tariff and revenue realization.
- Bhiwandi, a textile hub of the country, was reeling under a severe power shortage in 2006 with no investment in system improvements, inadequate metering, low collection, and high losses.
- Because of inaccurate aggregate technical and commercial loss figures in 2006, the bid for DF couldn't be based on loss reduction targets.
- DF was not subjected to minimum capex investment commitment.
- Torrent Power Ltd. built robust, safe, and reliable distribution network in these five years.
- Technical losses were reduced through network strengthening, revamping of low-tension network, maintenance and addition of distribution transformers, and reactive power management.
- Use of information technology applications like Supervisory Control and Data Acquisition (SCADA) and Automated Meter Reading (AMR) was introduced.
- Unauthorized connections were regularized under Ujjal Bhiwandi Abhiyan, especially in slum areas: 38,000 connections were regularized, and 17,000 new connections were provided.
- Torrent Power Company replaced more than 80 percent of the old meters with electronics meters.
- Two new customer service centers were opened.
- A round-the-clock call center and a mobile van were introduced for quick resolution of complaints.

See table BH.1.1.

Table BH.1.1 Bhiwandi Distribution Franchisee Parameters

<i>Parameters</i>	<i>2006–07</i>	<i>2010–11</i>
AT&C losses (%)	58	18.50
Number of transformers	2,254	2,611
DT failure rate (%)	42	3
Metering (%)	23	98
Collection efficiency (%)	58	99
Reactive compensation (MVAR)	0	160
Number of feeders	46	86
EHV capacity (MVA)	550	1,000
Number of customers	174,000	235,000
Use of IT	—	SCADA, AMR

Source: Deloitte research.

Note: AMR = Automated Meter Reading; AT&C = aggregate technical and commercial; DT = distribution transformer; EHV = extra high voltage; IT = information technology; MVA = million volt-amperes; SCADA = Supervisory Control and Data Acquisition; — = not available.

requirement and tariff petition as usual for its overall license area, irrespective of whether a DF has been appointed or not. Thus, the DF is virtually nonexistent for the regulator with regard to the routine business scenario.

The process for appointment of DFs does not fall under Section 63 of the Electricity Act of 2003 unlike the competitive bids held for procurement of power by distribution licensees or for development of requisite transmission lines, for which the Ministry of Power (MOP) has issued standard competitive bidding documents. Even the recommendation to privatize distribution networks of cities with a population of 10 million or more has been eliminated in the Mega Power Policy. At present, the central government has recommended the approach to mandatory franchising of rural areas only under the Rajiv Gandhi Grameen Vidyutikaran Yojana scheme. However, the MOP has not specified a policy directive, common approach to DFs in the form of standard bidding documents (SBDs), model DFA, baseline data requirements, and so on.

Although the Central Electricity Authority (July 2009) has issued a sample request for proposal for urban DF and the Forum of Regulators (September 2010) has issued a report on standardization of DFA, there are several differences between the two in certain key aspects such as area selection, bid parameters, minimum benchmark rate or reserve price, prequalification criteria, allowance of consortiums, quality of baseline parameters, loss reduction targets, and capital investments to be undertaken by the franchisee. Moreover, both of these documents are only suggestive or advisory in nature and have not been adopted by the utilities and licensees in the same spirit as was done in the case of the SBDs issued by the MOP for case 1, case 2, and independent power transmission company bids. A comparison of the two documents is provided in annex X to Volume 2, for reference.

Based on the experience of the various state utilities to date, it is recommended that the MOP develop well-conceived recommended guidelines and SBDs for both rural and urban franchisees. This action will have a far-reaching effect on reducing difficulties with the bid processes being followed across states and will increase the confidence of participants and investors. However, unlike generation and transmission, there is no provision under the Electricity Act 2003 to create guidelines or SBDs for DFs. Nevertheless, the central government through its MOP may undertake the following options to resolve the issue at a policy level:

- Amend the National Electricity Policy (NEP) to provide for the MOP to specify the guidelines and SBDs for appointment of DFs, separately in rural and urban areas. The guidelines can empower the respective state electricity regulatory commissions to permit any specific deviations from the guidelines and SBDs issued thereunder in keeping with the context of specific cases.
- Issue a set of guidelines and SBDs as a recommended approach to DFs, separately for rural and urban areas, that would not be binding on the state distribution licensees.¹

It should be noted that the guidelines and SBDs to be recommended by the MOP would need to distinguish between the routine activities of a distribution licensee, including outsourcing of certain functions such as billing, metering, and recovery, and those of a full-fledged, input-based DF for both rural and urban areas.

Based on the review of the past bidding experiences of utilities for appointing DFs, annex 3 in volume 2 contains a summary of findings that could be used in formulating a standardized approach to DFs in India.

Post-award Contract Management

Utilities that have undertaken implementation of the input-based franchisee model have faced several issues arising out of the contractual framework such as verification of the average billing revenue in the case of Bhiwandi and establishment of the process for third-party audit, which were not envisaged at the tendering or bidding stage. There could be situations of commercial complexities that the utilities may not otherwise be able to resolve in a timely manner, thereby leading to disputes, defaults, and so on.

It would be essential to train and deploy specialized personnel in a separate franchisee monitoring cell of the distribution utility, which could also act as the single point of contact for the franchisees, thus facilitating smooth implementation and monitoring of the franchisees. Finalizing such team structure at an appropriate stage and clearly defining the roles and responsibilities would be critical to success.

Personnel being deployed in such teams must be provided with intensive training on the provisions of the DFA and the modalities and implementation issues associated therewith. The DFA requires a specialized skill set and approach to monitor the performances of franchisees to ensure that the licensee's interests are protected and the objectives of appointing the franchisee(s) are achieved. Such a team could also undertake appointment of third-party agencies for independent auditing of the average billing rate; the subsidy booked or claimed, as applicable; and the asset register through field verification or validations on an annual basis.

Note

1. The Ministry of Power issued the standard bidding documents for appointment of input-based distribution franchisees in June, 2012.

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The passage of India's Electricity Act of 2003 was a signature achievement, moving the sector toward a market-driven approach that forced potential investors to compete aggressively for generation and transmission contracts. India's 2005 National Electricity Policy recognized electricity as one of the key drivers for rapid economic growth and poverty alleviation in the country. Yet the policy's target—electricity for all and 1,000 kilowatt-hours (kWh) available per capita by 2012—was not met. Despite a 20-year reform process and private-sector participation, the rate of resource augmentation and growth in energy supply has been less than the rate of increase in demand. Numerous challenges need to be addressed before India can overcome severe energy shortages and achieve its desired national policy objectives.

Private Participation in the Indian Power Sector: Lessons from Two Decades of Experience examines the home-grown Indian experience with private sector participation in power, identifies emerging risks, and proposes specific actions for government consideration, so that the power sector may fulfill its important role in India's growth story. Much has been achieved, and the Indian power sector can rightfully take its place among the bold reformers. Yet a large agenda remains, and a more rigorous focus on implementation, particularly on last-mile reforms in the distribution sector, will be required. Close coordination among various stakeholders and unrelenting attention to efficient execution through decentralized authority to make technical decisions, together with a robust emphasis on monitoring, evaluation, and transparent sharing of data and performance statistics, will help in achieving this objective.



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