

The Indian Electricity Market: Country Study and Investment Context

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About The Experience of Independent Power Projects in Developing Countries Study

Private investment in electricity generation (so called "independent power producers" or IPPs) in developing countries grew dramatically during the 1990s, only to decline equally dramatically in the wake of the Asian financial crisis and other troubles in the late 1990s. The Program on Energy and Sustainable Development at Stanford University is undertaking a detailed review of the IPP experience in developing countries. The study has sought to identify the principal factors that explain the wide variation in outcomes for IPP investors and hosts. It also aims to identify lessons for the next wave in private investment in electricity generation.

PESD's work has focused directly on the experiences with IPPs in 10 developing and reforming countries (Argentina, Brazil, China, India, Malaysia, Mexico, the Philippines, Poland, Thailand and Turkey). PESD has also helped to establish a complementary study at the Management Program in Infrastructure Reform & Regulation at the University of Cape Town ("IIRR"), which is employing the same methodology in a detailed study of IPPs in three African countries (Egypt, Kenya and Tanzania).

About the Author

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Disclaimer

This paper was written by a researcher (or researchers) who participated in the PESD study *The Experience of Independent Power Investment in Developing Countries*. Where feasible, this paper has been reviewed prior to release. However, the research and the views expressed within are those of the individual researcher(s), and do not necessarily represent the views of Stanford University.

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“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 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...”

Deepak S. Parekh, Chairman, Infrastructure Development Finance Corporation, September 2004¹

I. INTRODUCTION

This paper forms part of a wider study produced by the Program on Energy and Sustainable Development on the historical experience of Independent Power Producers (IPPs) in developing countries that have undergone varied levels of reform in their electric power sectors. The ultimate aim of the study is to explain patterns of investment in IPPs at the country and project levels, as well as variation in IPP experiences for both host countries and investors. We have endeavored to not only assess the historical record accurately, but also chart possible future paths for the IPP approach to power sector investment. This paper adheres to the research methods and guidelines laid out in the project’s research protocol.²

India stands out in our study as the second largest developing country market and features an evolving legal and regulatory regime created in the early 1990s specifically to promote investment in greenfield independent power projects. India’s electricity sector, which straddles state and federal jurisdictions, and India’s experience with a diverse range of greenfield independent power producers (“IPPs”) have produced dramatic variation in investor strategies and outcomes, ranging from the disastrous Dabhol Power Project in Maharashtra to the modestly successful GVK project in Andhra Pradesh and Paguthan project in Gujarat. The experience of host governments at the state level has also varied. Given the political dynamics of the Indian power sector, discussed in detail below, it is hardly surprising that nowhere in India have politicians and state offtakers displayed truly lasting enthusiasm about IPP development. In each of the four Indian states examined in detail in this study (Andhra Pradesh, Gujarat, Tamil Nadu and Maharashtra), officials have openly and regularly criticized IPPs. To various degrees, state politicians, offtakers, and regulators have attempted to gain, and have often achieved, further concessions from IPPs in response to perceptions of biased or unsustainable original deals. The problems with IPPs most often cited by central and state government officials and offtakers are relatively high construction costs (using state power plants of similar type and vintage as benchmarks), poor fuel linkage choices, unjustifiably high rates of return, and the resultant high

¹ N. Ramakrishnan, *Decade of power reforms -- Hardly electrifying*, THE HINDU BUSINESS LINE, September 4, 2001, quoting Deepak S. Parekh, Chairman, Infrastructure Development Finance Corporation.

² Victor, et al (2004). “The Experience with Independent Power Projects in Developing Countries: Introduction and Case Study Methods”, PESD Working Paper #23.

wholesale electricity tariffs borne by already cash-strapped state electricity boards. This paper sets out to describe the political, legal and economic context of India's experience with investment in greenfield IPPs and paints the broad contours of this experience from 1991-2004. The paper also offers some preliminary conclusions on the factors that have contributed to the IPP track record of the Indian government and investors, measured against the stated objectives of state and federal officials and the various foreign and domestic project sponsors.

II. INDIA: INVESTMENT ENVIRONMENT

With a population of over one billion people living in 28 states, India is the second most populous country in the world. Based on India's current population growth rate of 1.4% per annum, many predict that India will surpass China as the world's most populous country by the mid twenty-first century.³ It is clear that demands on the electricity sector will increase at a dramatic rate. India has a land area of approximately 3 million square kilometers (slightly more than one third of the United States' land area) and has recently made progress toward linking its 28 states through a national transmission grid. The country has ports on the Arabian Sea to the west, the Bay of Bengal to the east, and Indian Ocean to the south, providing it with port access to natural gas being shipped from the Persian Gulf region. India's GDP, based on purchasing power parity, is estimated at US\$ \$3.03 trillion for 2004 – currently the fourth highest in the world.⁴

A. The Macroeconomic Context

1. *Overview*

India entered the twenty-first century with per capita income around half that of China and Indonesia, countries that in 1970 were at comparable stages of development with India.⁵ This has led many development economists to question the relative success of India's economic growth over the past several decades. Reform measures adopted since 1991, however, have improved India's economic picture, as legislation has created a variety of openings in specific sectors of the Indian economy. India's economy, however, is still largely closed by international standards. Foreign firms, disappointed from past dealings with India's difficult bureaucracy and high taxes and tariffs, have become cautious about entering the market. Total foreign direct investment ("FDI") into India has ranged from \$3 to \$5 billion over the past several years, but this compares to roughly \$40-\$50 billion per year of FDI in China.⁶ One of the important reasons for the low level of foreign direct investment in India (FDI accounted for less than 1 percent of India's gross domestic product in 2002, compared to 4 percent for its rival China)⁷ is the fear of

³ CIA World Fact Book, July 2004.

⁴ World Bank Group, World Development Indicators, 2004.

⁵ World Bank. 2003. *India: Sustaining Reform, Reducing Poverty*. World Bank Development Policy Review. New Delhi. Oxford University Press.

⁶ U.S. Department of Energy, Energy Information Agency, India Country Analysis Brief (October 2004).

⁷ Foreign telecom investors in India are anticipating some of the same obsolescing bargain problems and regulatory takings experienced by IPPs. According to the executive of the Indian division of a major telecom company, "We have all sunk hundreds of millions of dollars into the Indian market on terms that may be radically altered. I am not sure whether New Delhi appreciates the damage this does to investor sentiment." Similarly, another foreign telecom participant recently stated that "We have watched with incredulity as Reliance's entry through the back door has

regulatory capture in important sectors of India's economy. Although India's economy has benefited from trade liberalization, relatively low inflation, increased levels of international trade and foreign investment, and an improvement in foreign reserves, the economy also continues to face the challenge of high budget deficits and poor infrastructure. The World Bank, for example, continues to express concern about India's perennially high public-sector budget deficit, running at approximately 10% of GDP in recent years.⁸

One unique feature of India among developing countries is its high number of well-educated people with English language and technical skills. As a result, India has emerged as a leading exporter of software services and software workers and the information technology sector ("IT") leads the country's strong economic growth pattern. Electricity and telecommunications are two of the key infrastructure inputs for economic growth in IT. Unpredictable state electricity supply, however, has led these growth industries, to the extent possible, to rely increasingly on captive power generation, thereby obviating the risks associated with uncertain supply from the state electricity grid. Technology entrepreneurs complain of having to pay large deposits to the local electricity board to obtain uninterrupted power supply for their startups.⁹

The negative factors that have affected India's economic outlook include high interest rates, political uncertainty, a large budget deficit, and weak global markets (as evidenced by the 4% low in GDP growth in 1997, during the Asian financial crisis). Ahluwalia (2002) has presented data suggesting that India's fiscal and debt indicators are comparable to or worse than those of Brazil, Turkey, and Argentina, countries that suffered serious macroeconomic crises in recent years.¹⁰ India's large foreign reserves, capital controls, flexible exchange rate system and large public ownership of banks may temporarily avert a large-scale fiscal crisis, but controlling the fiscal deficit and public debt are key concerns of Indian policymakers working in the electricity sector. For India, in contrast to China, the percentage of infrastructure contributions to fixed capital formation has declined sharply for at least fifteen years.¹¹ Set forth in Figure 1 are basic economic indicators over the past five years.

been legitimized ex ante by government regulators and in spite of its own rules." Edward Luce and Khozem Merchant, "The family-owned conglomerate has shown it can compete successfully in one global industry after another..." [no article title provided], THE FINANCIAL TIMES, October 21, 2003.

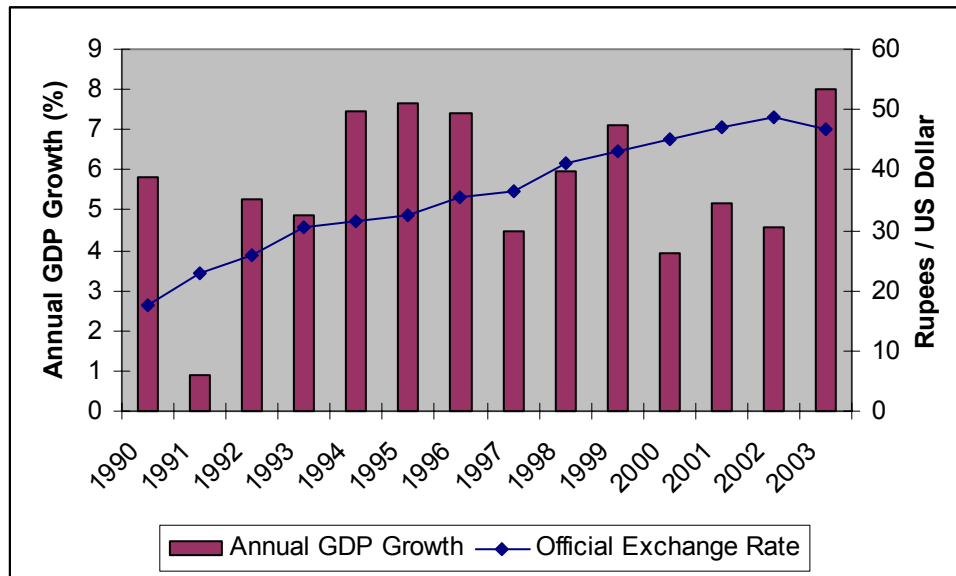
⁸ In 2003-2004, the overall deficit of the general government exceeds 10% of GDP, the primary deficit is 4.25% of GDP, and government debt is over 83 percent of GDP. The overall deficit and debt of the general government in India are greater now than during the run up to India's balance of payments crisis in 1991, when the overall deficit was 9.5% and government debt constituted 62% of GDP. See Roubini and Hemming, *A Balance Sheet Crisis in India* (2004).

⁹ Writing on the development of the IT sector in India, Nirvikar Singh writes that "[o]f the various infrastructure constraints, probably that of electric power is the most fundamental, and the most difficult one to tackle." Nirvikar Singh, *Information Technology and India's Economic Development* (April 2002); Rafiq Dossani and Martin Kenney, *Went for Cost, Stayed for Quality?: Moving the Back Office to India* (December 2003).

¹⁰ M.S. Ahluwalia, *Economic Reforms in India: A Decade of Gradualism*, 16 JOURNAL OF ECONOMIC PERSPECTIVES 3 (August 2002)

¹¹ R. Nagaraj, *Foreign direct investment in India in the 1990s: Trends and issues*, Economic and Political Weekly, (April 26, 2003).

FIGURE 1: SELECTED MACROECONOMIC INDICATORS, 1990-2003



Source: World Bank, World Development Indicators

2. Macroeconomic Growth

While India has achieved impressive economic growth over the last two decades, economists have expressed ongoing concern about its sustainability, most vocally during India's fiscal balance of payments crisis in 1991, and again after 1997-98, when fiscal deficits returned to around 10 percent of GDP range and government debt mushroomed.¹² During the decade of IPP presence in India, the economy has experienced real GDP growth ranging from 4% to 8%.¹³ Since 1990, the average growth rate has exceeded 6% and real growth in the country's GDP was 8.2% in 2003. This tracks with India's Tenth Five-Year Plan (running from 2002 to 2007), which calls for 8% GDP growth.¹⁴ India has performed most strongly in the service sector, bolstered by the success of India's information technology sector in attracting overseas business.¹⁵

Under the Planning Commission's most recent Five-Year Plan, the government indicated its intention to support India's aggressive economic growth target through the addition of 41,000 MW of new electricity. The Ministry of Power estimates that to support the government's 8% growth target, electric power supply will need to increase by more than 10% annually. By any

¹² See Brian Pinto and Farah Zahir, *India: Why Fiscal Adjustment Now?*, Economic and Political Weekly (2003).

¹³ U.S. Department of Energy, Energy Information Agency, India Country Analysis Brief (October 2004).

¹⁴ India's central Planning Commission releases Five Year Plans that provide a benchmark against which to measure economic progress against the Center's goals. The Planning Commission maps out five-year-plan investments for each sector of the economy, including power infrastructure. With this as background, the states work out their respective annual plans for each year based on estimated state and central resources. See <http://planningcommission.nic.in/plans/planrel/fiveyr/welcome.html>.

¹⁵ Rafiq Dossani and Martin Kenney, *Went for Cost, Stayed for Quality?: Moving the Back Office to India* (December 2003).

measure, such a capacity increase will require a high level of foreign investment. During the previous Five Year Plan, requisite levels of foreign investment in the power sector were not forthcoming, which led to electricity supply goals that were widely off the mark. Under the Ninth Five Year Plan from 1996 to 2001, the government called for 40,245 MW of new installed capacity. By 2001, only 19,100 MW of additional capacity was online, with the private sector contributing only a fraction of new generation.

3. *Inflation*

Inflation during the 1990s was above 8 percent on average, with a peak at over 16 percent in late 1991, when the balance of payments crisis led to sharp depreciation of the rupee and upward pressure on the price of industrial outputs.¹⁶ While government debt ballooned during the Ninth Plan from 1997-98 to 2001-02, inflation and interest rates began to converge with global trends toward 4% by the end of the period, despite a rise in the fiscal deficit and a significant increase in energy prices. This was due in large part to the Reserve Bank of India building up and sterilizing reserves designed to guard against exogenous macroeconomic shocks and control inflation.¹⁷ More recently, India has had record lows in interest rates, but many argue that low rates stem primarily from weakness in the global economy (with correspondingly low rates) and capital inflows, not better macroeconomic fundamentals.¹⁸ Inflation rates came down to 3.4 percent in 2002-03 and 5.4 percent in 2003-04, although recent high inflation figures due to rising commodities prices have led to estimates of an annualized rate of 7.3 percent for 2004.¹⁹

4. *Exchange Rate History*

The exchange-rate regime was liberalized with the devaluation of the rupee by 22% against the US dollar in two installments in July 1991. A market-determined exchange rate was introduced in March 1993 and current-account convertibility in August 1994. After a further devaluation in July 1993, the rupee remained constant at around Rs 31 to the U.S. dollar for two years before a nominal depreciation in 1995. The rupee gradually weakened to reach Rs47 to the U.S. dollar in July 2001 and has hovered between Rs46 and Rs48 to the dollar in the years that followed.²⁰ However, the currency has remained roughly constant in terms of the government's real effective exchange-rate calculation, which takes into account trade-weighted changes in the nominal rate against a basket of currencies and also relative inflation. Exchange-rate policy overall has focused on improving India's external competitiveness.

Infrastructure projects could theoretically eliminate foreign exchange risk by entering into a series of forward exchange rate currency hedging instruments. A currency hedge would allow a project to purchase for future delivery the amount of dollars needed to make each

¹⁶ Tim Callen and Dongkoo Chang, *Modeling and Forecasting Inflation in India*, IMF Working Paper (September 1999).

¹⁷ See Brian Pinto and Farah Zahir, *India: Why Fiscal Adjustment Now?*, Economic and Political Weekly (2003).

¹⁸ Id.

¹⁹ Arvind Panagariya, *Can Dr. Singh Cure His Economy?*, THE ASIAN WALL STREET JOURNAL, September 22, 2004; Anil Varma, *Rupee May Be Primed For Prolonged Strength*, THE ASIAN WALL STREET JOURNAL, December 2, 2004.

²⁰ CIA World Fact Book, July 2004.

scheduled debt service payment in return for delivery of local currency in amounts determined by the forward exchange rates in effect at the closing of the project's financing. In low-income countries, however, it is difficult to arrange forward foreign exchange transactions at an affordable cost with sufficient tenor to serve as the sole basis for financing an infrastructure project. As a practical matter, forward foreign exchange transactions have not generally been used as a component of financing for infrastructure projects in India or other developing or industrial countries.²¹

5. *Asian Financial Crisis*

With the onset of the Asian Financial Crisis, weak global markets did impact India's economy, but not as dramatically as the countries of East Asia. India's GDP growth slowed from approximately 7% in 1995-1996 to 4% in 1997. As discussed above, GDP growth regained momentum in subsequent years, fluctuating between 6 and 8 percent in recent years. Compared to the 40% to 70% depreciations that Asian currencies experienced during the crisis, the 15% depreciation experienced by the Indian rupee had minimal residual effects. Capital controls, while generating longer-term capital costs, appear to have limited India's vulnerability to the abrupt exodus of short-term capital. India, like China, also exercised greater central control over the foreign lending activities of its banks and corporations. The IMF argued that India's moderate slowdown reflected primarily domestic factors, particularly stalled structural reform and deteriorating public sector finances. Just as importantly, India was relatively isolated from the East Asia crisis, with trade contributing only 27% to GDP in 1997, with only a fraction of exports directed toward Asian markets (excluding Japan). Indonesia, Malaysia, Thailand, and South Korea, by contrast, had trade percentages ranging from 27% to 188% when the crisis occurred.²²

B. The Social and Political Context

As the world's largest democracy, India has displayed a great deal of political volatility at the federal, state and local level, and a calculation of political risk must factor into any large-scale foreign investment. According to recent International Country Risk Guide data tables,²³ India consistently ranks worse than the Peoples' Republic of China, the Philippines, Thailand, Malaysia, Poland and Mexico among those countries selected as representative for this study. The countries featured in our IPP study with greater country risk during the past year are, in increasing order of risk, Turkey, Argentina, Brazil, and the Philippines.²⁴ The presence of numerous factors in some projects has heightened the political risk normally associated with emerging market infrastructure development. One particular aspect of India's IPP program that has received a great deal of attention is the "fast-track" procedure available under the 1991 Amendments. Of eleven fast tracked projects, only three successfully achieved commercial

²¹ Tomoko Matsukawa, Robert Sheppard and Joseph Wright. *Foreign Exchange Risk Mitigation for Power and Water Projects in Developing Countries*, The World Bank Group (2003).

²² Id.

²³ For an analysis of the strengths and weaknesses of the ICRG analysis, see Anja Linder and Carlos Santiso, *Assessing the Predictive Power of Country Risk Ratings and Governance Indicators* (Working Paper, October 2002).

²⁴ International Country Risk Guide, *Aggregate Country Risk Tables* (The PRS Group, March 2004), available at <http://www.icrgonline.com/>.

operation. IPPs under India's "fast-track" program were not subject to competitive tender, which often led to charges of public corruption and malfeasance levied by political leaders, NGOs and the vocal Indian press. Likewise, lack of transparency (e.g. for some IPPs, documents including the final PPA were never made public) and the apparent alacrity of the decision-making process fueled further speculation of bribery and corruption.

From 1990 onward, the social and political landscape of India experienced a number of significant developments: the rise of regional social and political forces; the economic crisis of 1991 resulting in structural adjustment; social conflict due to implementation of the Mandal Commission report on the treatment of lower castes; mobilization of the Hindu majority by the Bharatiya Janata Party ("BJP") based upon the ideology of Hindutva, and steady erosion of the Nehruvian consensus on socialism and secularism. These changes have created fragmentation and conflict within the electorate, leading to breakdown of the single party system. This system was led by the Congress Party, which dominated since independence. With the transition toward a new and still evolving multiparty system, the two leading parties, Congress and BJP, have only found success through the building of complex and fragile coalitions with regional parties. "Hung parliaments" resulted from every national election through the 1990s, which produced a series of unstable and short-lived coalition governments.²⁵ Atal Bahari Vajpayee, thrice prime minister under various BJP coalitions, epitomized the instability of the new multiparty system. His party's political vicissitudes had their impact on at least one high-profile IPP renegotiation in the country. In 1996, Mr. Vajpayee was prime minister for less than two weeks, followed by eighteen months in the government's top post in 1998 and a final full term in office that ended in 2004. As will be seen, the political risk of renegotiated contracts in India is closely associated with regime changes such as these. Following the recent 2004 election, in which Congress unexpectedly swept back to power over the incumbent BJP coalition, Manmohan Singh became the new Prime Minister. Singh's new government is a blend of veteran Gandhi family loyalists and powerful regional politicians allied with the Congress party. It remains to be seen exactly how this new government will address the needs of the Indian electricity sector.

1. *Government Structure*

India's constitution has not undergone changes in its basic structure of federal parliamentary democracy since its adoption in 1950. Data shows that the social composition of the Lok Sabha, India's parliament, has become more representative of Indian society. The proportion of members elected to the Lok Sabha from rural areas was 62.9 percent in 1996, with 35.6 percent of the Lok Sabha comprised of farmers. The Lok Sabha is not at all dominated by the middle and upper-class castes, with the number of Brahman members down from 23.3 percent to 8.2 percent between 1952 and 1996. Two trends repeatedly came to the fore during the first decade and a half of private investment in electricity generation. First, increasingly organized social movements (sometimes referred to as grassroots politics) proliferated across the country. Social movements arose in particular as a response to violations of civil liberties, human rights, environmental degradation, and population displacement caused by infrastructure

²⁵ Sudha Pai, *Parties and Political Stability in India: Problems and Prospects*, Centre for Political Studies, JNU, New Delhi (2000).

development projects.²⁶ Second, and interrelated, the historically disadvantaged lower castes began to assert themselves politically with greater success. These castes include the *dalits*, or untouchables, and other castes officially designated as the “Other Backward Classes.” For example, the Hindu nationalist party, Shiv Sena, which became a powerful force in the state of Maharashtra, was said to have a particularly strong support in the growing urban slums. Because it has become increasingly difficult for single political parties to secure a majority in the Lok Sabha alone, coalition ministries have governed at the center, sometimes composed of more than ten parties. As part of this trend, regional parties, which have maintained their influence at the state-level, have now also risen to important strategic positions within national politics.²⁷ India has recently struggled with the emergence of the Hindutva movement, which gained ideological ground in the 1990s and sought to redefine democracy along more majoritarian, Hindu nationalist lines.

2. *Political Forces*

Two deeply divisive issues confronted the Indian polity during the era of IPP investment: secularism and the economic crisis. The two major parties attempted through shifts in their ideology, organization, social base and leadership to address these issues and thereby prevent instability. The period that saw the opening of the generation sector was one of political instability following the breakdown of the Congress party and Nehruvian consensus, which had previously survived in one form or another since independence. The 1990s was a decade of confrontation between the major national parties, as each struggled to mobilize a social base to gain a majority and form a government alone. In this highly politicized environment, the parties avowed strong positions on economic issues and marshaled their forces along the fault lines of social cleavages, resulting in fragmentation and conflict within the electorate. The second half of the 1990s was a period of greater moderation, which saw the dominant parties attempting to moderate their ideology, broaden their social base and form more stable coalitions. Increasing regionalization of national politics in India has now prevented any one national party from ruling without their support. On the other hand, regional party politicians, despite demanding a share in central governance, must still focus primarily on the regional political arena in order to strengthen their home base.²⁸ This push and pull between regional politics and national energy policy forms an important backdrop to international investment in IPPs.

The Indian corporate landscape is distinguished by very high concentrations of ownership. One study in 1996 estimated that the leading fifty Indian business houses controlled 44 percent of private sector assets. The great majority of the most valuable companies are family businesses. Large Indian corporations and industrial conglomerates are well represented locally and at the highest levels of government by powerful trade associations, which include the

²⁶ James Chiriyankandath, *Introduction: Situating Indian Democracy*, in *DEMOCRACY IN INDIA*, ed. Niraja Gopal Jayal (Oxford University Press, 2000). Unlike contemporary social movements in the United States and Western Europe, which tend to be led by the middle-class, social movements in India are dominated by the lower classes. For example, ecological conflicts have not generated middle-class movements, but rather have involved livelihood struggles among people directly dependent on natural resources. Id.

²⁷ Rajendra Vora & Suhas Palshikar, *Introduction*, in *INDIAN DEMOCRACY: MEANINGS AND PRACTICES* (2004), ed. Rajendra Vora & Suhas Palshikar.

²⁸ Sudha Pai, *Parties and Political Stability in India: Problems and Prospects*, Centre for Political Studies, JNU, New Delhi (2000).

Confederation of Indian Industries (“CII”) and the Federation of Indian Chambers of Commerce and industry (“FICCI”). Since the movement for Indian independence, industrial groups have maintained close ties with the political elite. Prior to liberalization, Indian business houses, the great majority of which are family-owned and operated, had ‘industrial embassies’ in Delhi for lobbying purposes,²⁹ and this presence continues to exert influence after the liberalization measures of the 1990s.

Smaller state-level and local business interests also impact the political parties at the state level. For example, allegiance with small businesses, particularly in the northern states, was essential to the BJP’s various ruling coalitions throughout the 1990s.³⁰ The influence of the industrial lobby at state and federal level, as well as the demands of more local business interests through the democratic political process, continues to constrain the development and implementation of electricity sector reform and credible independent regulators.

Elections are regularly held at the state and national level and are generally viewed as relatively free and fair. Most commentators believe that the chief stumbling blocks for Indian democracy are the accountability and responsiveness of politicians and bureaucrats. While voters have the ability to vote out poorly performing, corrupt or repressive regimes, India’s governance structures and procedures continue to lack transparency and remain largely inaccessible to the ordinary citizen.³¹

3. *Human Rights*

Although the Indian constitution and law demand otherwise, it is not uncommon to find occurrences of state personnel, such as local police, not only failing to protect citizens from unlawful coercion and violence but also engaging in violation of citizens’ rights. When the rule of law has not taken hold at the local level, subordinate social groups are often subject to abuse.³² International NGOs Amnesty International and Human Rights Watch, for example, both prepared extensive documentation on alleged “suppression by state authorities in Maharashtra of peaceful protests,” charging Enron with corporate complicity in human rights violations. Human Rights Watch documented numerous instances of violence and threats by state personnel of villagers and other activists protesting the development of the Dabhol Power Project in Maharashtra.³³ The Subcommittee Report in 2002 found that the police failed to investigate

²⁹ D. Encarnation, (1989), *Dislodging Multinationals: India’s Comparative Perspective*, Cornell University Press, Ithaca, New York. For example, in Chennai, only five of the 31 companies represented in the list of the top 500 Indian companies are not family businesses. Seven of the 31 companies are held by a single family group. John Harriss, *On Trust, and Trust in Indian Business: Ethnographic Explorations* (August 2002).

³⁰ John Henley, *Chasing the Dragon: Accounting for the Under Performance of India by Comparison with China in Attracting Foreign Direct Investment* (August 2003).

³¹ *Id.*

³² *Id.*

³³ Amnesty International, *The ‘Enron Project’ in Maharashtra – Protests Suppressed in the Name of Development* (Amnesty International ed., July 17, 1997); Human Rights Watch, *The Enron Corporation: Corporate Complicity in Human Rights Violations*, (Human Rights Watch ed., 1999).

alleged attacks and harassment of project opponents by State Reserve Police and security guards stationed at the plant at DPC's expense.³⁴

4. *International Political Disputes*

India's rivalry and protracted territorial dispute with Pakistan has defined Indian politics since the partition of British India in 1947. Political tensions between India and Pakistan have had relatively modest adverse effects on India's economy. The conflict has direct implications for the energy sector, however, as the conflict hinders plans for regional natural gas and/or oil pipelines originating in Central Asia. More recently, since the Vajpayee administration, relations between India and Pakistan began to thaw, and future developments may allow for more cross-border activity in the electricity sector.

C. Foreign Direct Investment Policy and Experience

Weak infrastructure (particularly energy and transportation), anti-export biases, complex labor laws, cumbersome administrative procedures (especially customs and excise taxes), and government reservations and subsidies for small-scale industry continue to discourage FDI flows on a scale commensurate with the size of the Indian economy.³⁵ FDI flows, as a result, are diminutive when compared with China.³⁶ Studies have shown that the major determinant of investors' decisions in India is the availability of good quality infrastructure.³⁷ Yet in a vicious cycle, state governments have struggled to fund the infrastructure development required to attract larger volumes of FDI, notwithstanding evidence of strong positive complementarities between public investment in infrastructure and private investment generally.³⁸ The largest foreign investors are Mauritius (some 44% in 2000/01), which has the most favorable tax avoidance treaty with India, followed by the United States (16.8%).³⁹ Foreign investors in Indian IPPs almost always structure their investments using Mauritius holding companies. The originating point of FDI that passes through the Mauritius tax haven, however, is not statistically available.

1. *Patterns of Foreign Direct Investment*

Annual foreign direct investment in India has averaged between US\$ 3 to US\$ 4 billion during the past several years, a figure which pales in comparison to foreign investment flows to China in excess of US\$ 40 billion. Until July 2003, the Reserve Bank of India ("RBI"), which prepares India's FDI statistics, prepared, only recorded FDI flows arising from direct equity investments. Based on the standard IMF definition, this resulted in undercounting FDI by excluding reinvested earnings, royalty payments, inter-company debt transactions and commercial borrowing by foreign direct investors. Official Indian FDI statistics thus have a significant downward bias. An International Finance Corporation ("IFC") estimate suggests that

³⁴ CABINET OF MAHARASHTRA SUB-COMMITTEE, REPORT OF THE CABINET SUB-COMMITTEE TO REVIEW THE DABHOL POWER PROJECT [hereinafter SUB-COMMITTEE REPORT], available at <http://www.hrw.org/reports/1999/enron/enron-b.htm>.

³⁵ World Trade Organization, *Trade Policy Review India: Report by the Secretariat* (May 2002).

³⁶ Henley (2003)

³⁷ C.P. Oman, *Policy Competition for Foreign Direct Investment*, OECD (March 2000).

³⁸ Henley (2003)

³⁹ World Trade Organization (2002).

India's actual FDI inflow in 2001 was between US\$5 billion and US\$8 billion. A Planning Commission Report argues that if allowance is made for double-counting of FDI in China, then China's FDI inflow to GDP ratio is only 1.8 percent. Yet this still doubles the adjusted ratio of FDI inflow to GDP for India.⁴⁰

(a) Sectoral Flows

The Government of India first liberalized FDI equity caps in central government-controlled infrastructure sectors where the state was unable to finance the desired level of investment (power, telecommunications, transportation infrastructure and large-scale urban development). In this respect, Indian FDI statistics show the clear impact of changes in government investment regimes on FDI sectoral flows. In 1991, India opened up its telecommunication and electricity generation sectors to FDI. Between 1991 and 2000, electricity generation attracted the greatest share of FDI, accounting for 25 percent of total flows of foreign capital. After the power sector, 18.5 percent of FDI went to mobile phone companies and 10 percent to electrical equipment (which includes software). A 2003 study presented evidence that the Indian manufacturing sector, when subject to competition from imports and FDI, experienced significant productivity growth.⁴¹ An important question for further exploration is whether the power sector also experienced an increase in productivity following the introduction of IPPs after 1991.

(b) Geographic Flows

In addition to distinct sectoral flows, particularly to power generation, Indian FDI also tends to concentrate in more developed states with more advanced infrastructure. From mid-1991 to mid-2002, roughly 45 percent of newly approved FDI by value was made into the relatively industrialized states of Maharashtra (17 percent), Tamil Nadu (8 percent), Karnataka (8 percent), Gujarat (7 percent) and Andhra Pradesh (5 percent). The capital, New Delhi, attracted a further 12 percent of approved FDI. The official statistics do not allocate 26.8 percent of approved FDI to particular states, but presumably the geographical distribution of FDI is similar to where target destination is declared. This leaves approximately 16 percent of FDI for the 23 remaining states and 6 union territories, which currently constitute 66 percent of India's total population.⁴² These geographic concentrations of FDI in the power sector and more generally create an important dynamic in India's overall economic development. Ahluwalia has argued that private investment levels provided the main driver of state-by-state differences in economic growth. Public investment, on the other hand, has had no discernible impact on growth according to this study. High growth states are, with the one exception of West Bengal, the states attracting the greatest shares of FDI.⁴³ If the power sector, as the largest sectoral recipient of FDI, is an important factor in this trend, than a successful state-level experience with IPPs may have important implications for general state economic growth.

⁴⁰ Planning Commission, *Foreign Investment India: Report of the Steering Group on Foreign Direct Investment Chaired by N. K. Singh*, Government of India, New Delhi, August 2002, p.16-17; Henley (2003).

⁴¹ Henley (2003), citing B. Unel (2003), *Productivity trends in India's manufacturing sectors in the last two decades*, IMF Working Paper WP/03/22.

⁴² Henley (2003). See also http://iic.nic.in/iic2_c03.htm and <http://www.censusindia.net/results/rudist.html>.

⁴³ M.S. Ahluwalia, *State level performance under economic reforms in India*, Center for Research on Economic Development and Policy Reform Working Paper No. 96, Stanford University (March 2001).

(c) Entry and Exit

Ideally, investors in IPPs, whether foreign or domestic, would like to have the ability to enter or exit new or existing projects with a minimum of transaction costs. Business organizations such as the Confederation of Indian Industries (“CII”) have also argued that excessive regulation of entry and exit forms a key barrier to private investment. For example, a hotly debated policy issue in India is the liberalization of merger and acquisition activity, which would effectively remove exit barriers for foreign investors. The Planning Commission Report has recently proposed the elimination of almost all exit barriers. Among significant barriers, the Commission only recommends against removing the prohibition on local borrowing by foreign investors to fund share purchases.⁴⁴

2. *Legislation on FDI*

Through the 1990s, India implemented a series of reforms that sought to encourage foreign investment. Since the 1991 Electricity Act Amendments, which opened the door for domestic and foreign IPPs, legislation has aimed at facilitating foreign direct investment in power projects. Subject to government approval, the 1991 Amendments allowed up to 100 percent foreign ownership of power plants. A debt-to-equity ratio up to four-to-one was permitted to prospective entrants into electricity generation.⁴⁵ The 1991 reform legislation also specifically aimed to attract *foreign* investment in IPPs, evident from a provision that Indian financial institutions could lend no more than 60 percent of the total debt for projects.⁴⁶ Reform legislation also lowered custom duties on imported capital goods, and in some cases import tariffs were eliminated (for example, on large scale power generation equipment such as turbines).

Although foreign investors frequently complain that their business activities are over-regulated in India, the fact is that very few restrictions and regulations apply to foreign investments that do not also apply to domestic investments.⁴⁷ Although the government has put in place equity limits on FDI in a few strategic sectors, India still generally extends national treatment to foreign investors.⁴⁸ This general observation is also applicable to foreign investment in IPPs, although national treatment hardly provided for a painless and straightforward process for foreign investors unfamiliar with the complex permitting requirements and government approvals required to develop a power plant in India.

3. *The License Raj*

States have also made varied progress in rolling back India’s historically intrusive regulatory bureaucracy, previously referred to as the “Inspector Raj.” This task that has become

⁴⁴ Id.

⁴⁵ International Energy Agency, *ELECTRICITY IN INDIA: PROVIDING POWER FOR THE MILLIONS* (2002).

⁴⁶ Navroz K. Dubash & Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, *ECONOMIC AND POLITICAL WEEKLY* (Sept. 1, 2001).

⁴⁷ Planning Commission, *Foreign Investment India: Report of the Steering Group on Foreign Direct Investment Chaired by N. K. Singh*, Government of India, New Delhi, August 2002..

⁴⁸ World Trade Organization (2002).

a competitive mandate for attracting private capital. Business managers of Indian firms, whether domestic or foreign-owned, have long argued that regulation of business activity is inefficient and unduly burdensome. Domestic and foreign complaints about red-tape in India stem from what is now called the “License Raj,” the interventionist, command-and-control industrial policy followed by India up until, and to a lesser extent after, the gradual liberalization of the 1980s and 90s. The aftereffects of the License Raj continued to be felt in the power sector following the 1991 reforms.

A useful measure of the bureaucratic hurdles encountered by both foreign and domestic firms in India can be found through comparison with China. To this end, the World Bank conducted surveys of a sample of firms in India and China in 2002. The World Bank study concluded that starting a new business in India required on average ten permits, compared to the six permits required to legally establish the same business in China. The permitting process took 90 days in India, three times longer than in China. For Indian IPPs with foreign investors, the survey reports that it took an average of 43 permits at the central government level and 57 at the state level to obtain clearance. The same clearances are required for domestic and foreign invested firms.⁴⁹

Once permits and clearances are obtained, investors are still faced with a high level of government oversight – the so-called “inspector Raj.” Large international project sponsors with political connections and management expertise in developing countries may find this only a minor irritant. The management time required to accommodate a steady stream of inspections, however, becomes burdensome for small to medium-sized operations. In India, 16 percent of senior management’s time may be occupied by interactions with government officials, as compared to 9.9 percent of management time in China.⁵⁰ Foreign investors in the power sector may find this less burdensome if they can rely on their local partner or carefully selected local manager to liaise with officials. Reforms in the power sector, including the 2003 Electricity Act described below, have endeavored to cut back drastically on the amount of red tape that historically attended the electricity sector. Complete removal of the onerous ‘inspector Raj’ artifacts that remain will require continued devolution of state power through improved corporate governance, as well as greater professionalization and compensation of civil servants. It is hoped that a systematic approach will minimize the rent-seeking that has traditionally characterized India’s bureaucratic labyrinth.

4. *Contract Enforcement*

Another important factor for IPP investors, particularly for foreigners, is contract enforcement. Contract enforcement has proved to be one of the foremost problems cited by foreign investors when IPPs have soured. In depth discussion of this issue can be found below in the section of renegotiation of PPAs. Moreover, Indian debt recovery and bankruptcy proceedings are viewed as long and drawn-out. The exceedingly slow timetable for resolution of debt recovery and bankruptcy claims partially explains the failure of DPC stakeholders to reach a settlement. The CII asserts that it is ‘normal’ for debt recovery proceeding to take more

⁴⁹ Henley (2003)

⁵⁰ Id.

than two year, and enforcement can reportedly take over a decade in some cases.⁵¹ Given these inadequacies in the legal regime, it becomes all the more important for foreign investors and smaller players to use an Indian company with the necessary political clout to achieve results outside of court.

5. *The Wider Reform Experience*

For most of its history, India's economic policy was driven by import substitution and state ownership of key industries. From the early to mid-1990s, the government embarked on a series of economic reforms that relaxed restrictions on foreign ownership in some sectors and led to privatization of some industrial state owned enterprises. The 1990s also saw a pronounced shift in governance patterns from direct state regulation to independent regulation a step removed from the political process. Sectors that saw substantial reforms during the 1990s include finance and banking, insurance, telecommunications, and electricity.⁵² Since the 1990s, India has remained committed to promoting competitive forces in these key industrial sectors. For example, in January 2003 the government decided in favor of selling the state's majority stake in two downstream oil companies, Hindustan Petroleum (HPCL) and Bharat Petroleum (BPCL). In the energy sector, further reforms are currently under consideration, including deregulation of natural gas prices (although some state officials argue that gas suppliers remain too concentrated to allow for efficient pricing).

III. ELECTRICITY MARKET CONTEXT

A. Overview

India is the world's sixth largest energy consumer, relying on coal as the primary energy source for over half of its total energy needs. Thermal power plants produce more than three quarters of India's electricity, taking advantage of India's position as the third largest producer of coal in the world. The electricity sector has long experienced capacity shortfalls, poor reliability and quality of electricity (voltage fluctuation, etc.) and frequent blackouts. Industry cites electricity supply as a major impediment to economic growth. Despite reforms introducing private participation during the 1990s, the India's electricity sector has remained dominated by the state since India's independence in 1947. The Electric Supply Act of 1948 integrated smaller fragmented utilities into 19 state electricity boards. SEBs remain the dominant institutions within India's electricity industry, controlling well over half of the electricity supply and the vast majority of distribution. The SEBs fall under the jurisdiction of individual state governments. Currently, the financial losses of the SEBs total to nearly US\$ 6 billion, amounting to 1.3% of India's GDP.⁵³

India's federal system creates an institutional environment of shared authority over power projects. The political, institutional and economic context for private investors varies

⁵¹ Id.

⁵² Navroz K. Dubash & Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, ECONOMIC AND POLITICAL WEEKLY (Sept. 1, 2001).

⁵³ U.S. Department of Energy, *An Energy Overview of India* (2003).

substantially across states, which allows for partially controlled conclusions when comparing outcomes. Because India could not adequately address the country-wide shortage in electricity supply through state and federal deficit spending, federal and state reforms aimed at minimizing the role of cash-strapped and inefficient state electricity boards (“SEBs”) and empowering independent regulators across the country. States were given wide latitude to pursue their own reform plans. Some states privatized distribution, others unbundled their SEB, and a few opted against structural reform, keeping the SEBs intact and reforming internally.⁵⁴

With the introduction of independent regulators in 1998, independent electricity regulatory commissions at the state level have primary responsibility for setting retail electricity tariffs and approving tariffs between IPPs and the state SEBs. The Indian Constitution lists electricity as a “concurrent” responsibility of the state and federal governments, meaning that the state legislature’s authority overlaps with the central government. In the event of a conflict between overlapping state and federal authority, the federal parliament in New Delhi can exercise preemptive power. The concurrent listing of electricity in the Constitution has opened the door, however, to delays in the implementation of statutory economic reforms when disagreements occur between the central government and state parliaments.⁵⁵

B. Electricity Supply and Demand

From 1990 to 2000, annual electricity generation and consumption nearly doubled and India’s projected annual rate of growth in energy consumption (2.6% to 4.5%) is the highest of any major country. Estimates of the current electricity supply shortage for peak capacity range from 11% to 18%. A summary of electricity generation, by project type, and electricity consumption during the period under review in the IPP study is set forth below in Table 1. Installed capacity from 1990 to 2001 is listed in Table 2 by project energy source.

TABLE 1: ELECTRICITY GENERATION AND CONSUMPTION, 1990-2001 (BILLION kWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Net Generation	275.5	300.3	315.9	339.3	366.1	395.8	412.7	441.2	470.7	503.7	512.0	533.3
<i>hydroelectric</i>	70.9	72.0	69.2	69.8	81.9	72.0	68.4	73.9	82.2	79.9	73.7	77.4
<i>nuclear</i>	5.6	5.2	6.0	5.9	4.7	6.5	7.4	10.5	10.6	11.5	14.1	18.2
<i>geo/solar/wind/biomass</i>	0.0	0.0	0.0	0.1	0.2	0.1	0.8	1.0	1.1	1.4	1.6	1.8
<i>conventional thermal</i>	198.9	223.1	240.7	263.6	279.3	317.2	336.1	355.8	376.8	410.8	422.6	435.8
Net Consumption	257.1	280.6	295.1	316.9	341.9	369.7	385.4	411.7	439.1	469.4	477.5	497.2
Imports	1.0	1.4	1.4	1.4	1.6	1.7	1.7	1.6	1.5	1.4	1.5	1.5
Exports	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2	0.3

Note: generation components may not add to total due to rounding

Source: DOE/EIA

⁵⁴ See, generally, Rahul Tongia, Stanford-CMU Indian Power Sector Reform Studies (February 2003).

⁵⁵ U.S. Department of Energy, *An Energy Overview of India* (2003).

TABLE 2: INSTALLED ELECTRICITY GENERATION CAPACITY, 1990-2001 (THOUSANDS OF MW)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Hydroelectric	18.31	18.76	19.20	19.58	20.38	20.84	20.99	21.10	21.89	22.44	24.50	25.14
Nuclear	1.57	1.57	1.79	2.01	2.01	2.23	2.23	2.23	2.23	2.23	2.23	2.86
Geothermal/Solar/ Wind/Biomass	0.02	0.03	0.03	0.04	0.05	0.12	0.55	0.82	0.93	1.02	1.08	1.27
Conventional Thermal	51.86	54.35	57.35	60.75	65.04	69.19	71.89	73.40	75.19	77.77	80.35	82.51
Total Capacity	71.75	74.70	78.37	82.38	87.48	92.38	95.66	97.55	100.23	103.45	108.15	111.78

Note: components may not add to total due to rounding

Source: DOE/EIA

While the world average per capita consumption of electricity exceeds 2000 kWh annually, India lags far behind at only 300 kWh per annum.⁵⁶ Like many developing countries, India cannot afford to construct the new generation capacity required to meet its growing demand for power. The 100 gigawatts of new capacity that India will require between 2002 and 2012 according to recent forecasts will require an estimated capital outlay of \$120 - \$160 billion. Even at the low end of current forecasts, the level of expenditure required to meet demand remains well beyond the reach of the Indian government.⁵⁷

Another central political aspect of India's energy strategy is the Rural Electrification Action Plan, which calls for countrywide electrification of villages by 2007.⁵⁸ Although the rural electrification plan do not relate directly to IPPs, it is important to note its political importance, as the goals may be perceived as running contrary to private participation in the near term.

C. Fuel Sources

Thermal power plants have a critical dependence on reliable fuel supply, which has often created challenges and vulnerabilities for IPPs in both the development and operational phases when fuel markets face shortage, become unstable or distorted. PESD has found in any earlier study that the management of input factor markets, particularly domestic fuel markets, has had a substantial impact on the ability of reformers in the electricity sector to alter the organization, efficiency and financial solvency of the state system. In India, where private investment in generation occurred at the vanguard of energy sector liberalization in only partially restructured or nominally reformed state power sectors, private generators have in many cases borne the brunt of fuel market challenges.

In the energy sector, the state has not only regulated the price of electricity, but has also set fuel prices and has had a hand in allocating fuel resources. India's ambivalent approach to

⁵⁶ Id.

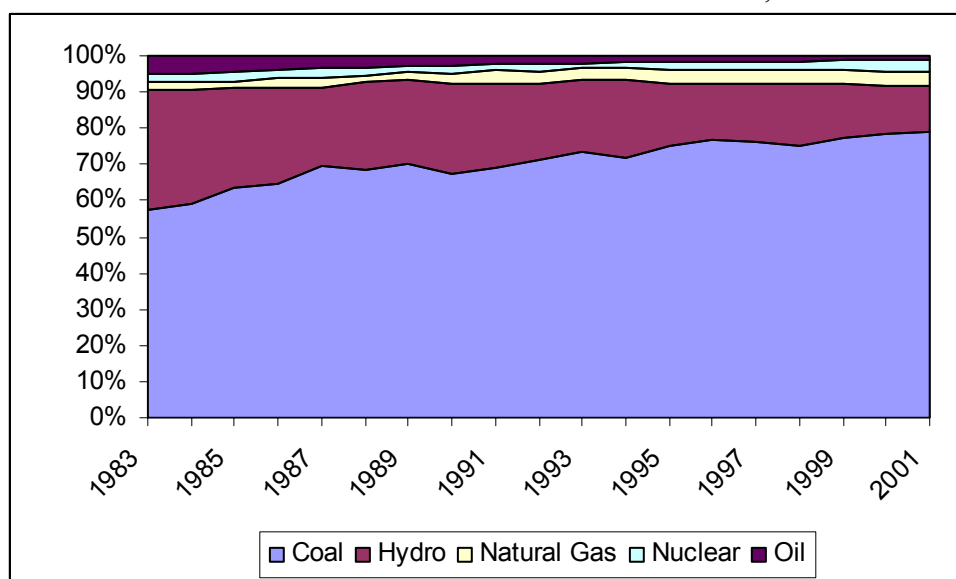
⁵⁷ Ahmad Faruqi, *Pricing Reform in Developing Countries*, POWER ECONOMICS (September 2002).

⁵⁸ U.S. Department of Energy, *An Energy Overview of India* (2003).

fuel allocation for IPPs reflected the tension between the country's overall economic reform policies, which emphasized self-reliance and import substitution, and the need to import foreign fuel due to domestic shortages and lack of institutional coordination.

Fuel linkage became a crucial issue from the development stages through operation for nearly every IPP in India. Although the Power Ministry was the central government ministry responsible for pushing forward electricity sector liberalization, for liberalization to work the Ministry needed to consult and cooperate with numerous other government agencies, particularly those with regulatory oversight over the fuel sources required for proposed power projects. The Power Ministry had its own legacy of failed coordination with other agencies, which elevated the bureaucratic hurdles that developers had to pass. Policymakers, regulators and bureaucrats outside of the Ministry of Power often failed to cooperate fully with the electricity sector liberalization plan, citing well-established and complex rules concerning fuel security, import substitution, environmental protection and economic development policy. Because of the politics and uncertainty surrounding domestic fuel linkages and the status of fuel cost as a pass-through item under standard PPAs, many project sponsors preferred to import fuel (such as LNG) for their IPPs notwithstanding high fuel import tariffs. A series of restrictions on fuel imports put in place by the Ministry of Commerce limited import options, particularly with respect to petroleum-based fuels. The government attempted to address the political and institutional conflicts surrounding the allocation of scarce domestic fuel resources when the Ministry of Petroleum gave the green light for the use of naphtha as an interim fuel for short gestation gas-fired IPPs, which eventually led to a temporary crisis situation, discussed in detail below, for a large number of IPPs in India.⁵⁹

FIGURE 1: ELECTRICITY GENERATION BY FUEL SOURCE, 1983-2001



Source: World Bank, World Development Indicators

1. Coal

⁵⁹ Navroz K. Dubash & Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, ECONOMIC AND POLITICAL WEEKLY (Sept. 1, 2001).

With the second largest coal reserves in the world (approximately 7% of the world's total), the Indian government over the past decade and a half has continued to emphasize its importance in the energy sector. Nearly 75% of India's electricity comes from coal. India's coal deposits occur mostly in the east central part of the country, with major coal fields lying in Bihar, West Bengal and Madhya Pradesh. Coal India Limited, the world's largest coal company, owns nearly all of the country's coal mines and produces about 90% of the coal. Low productivity fields, distribution problems, and market share loss to higher quality, less expensive coal from overseas characterize CIL's operations. Most Indian coal has a high ash content and low calorific content. Due to the high ash content, the government has sought new advanced coal scrubbing technologies and has passed regulations mandating the cleaning of coal. Regulations require that all coal shipped to new generation plants are processed for ash removal in coal washeries. The US Department of Energy indicated that India planned to generate half of its future electricity supply using its domestic coal source. The government has shied away from privatizing the country's coal production. During the period under review, the law provided for captive mining operations dedicated to a power plant or factory, but otherwise barred private mining operations. The government abandoned plans for coal-sector liberalization in the face of strong opposition from labor unions. Coal prices were not fully deregulated until April 2000 upon passage of the Colliery Control Order, which superseded prior orders and legislation that empowered the government to fix coal prices by grade and colliery.⁶⁰

IPPs reportedly faced numerous obstacles in securing contracts for domestic Indian coal. The vertically integrated SEBs had a poor payment history to the state-owned companies managing coal and the railway transportation system for coal. Because of the legacy of payment default from the SEBs to the ministries overseeing coal supply and delivery, the Ministry of Coal and Ministry of Railway refused to alter their procedures to the extent necessary to accommodate IPPs. The ministries believed that the payment risk, which in the past was directly attributable to cash-strapped SEBs, was still an issue: although a coal supply contract would be entered into with a project company, the SEBs would continue to bear the full fuel cost through the pass-through mechanism in the standard PPA tariff. The fear was that this in turn could translate back into payment risk for the state ministries in the event of SEB default on payments to IPPs.⁶¹

2. *Natural Gas*

Although many Indian policymakers have opposed excessive reliance on oil and natural gas because they are subject to greater price and supply uncertainty and would require even greater net energy imports, Indian consumption of natural gas has risen faster than any other fuel in recent years. Natural gas consumption has grown from only 0.6 trillion cubic feet (Tcf) per year in 1995 to 0.8 Tcf per year in 2000, with projections of 1.2 Tcf in 2005 and 1.6 Tcf in 2010. Reliance Industries announced the discovery of a large natural gas reserve in the Krishna-Godavari Basin, offshore of Andhra Pradesh on India's southeast coast. New reserves from the Krishna-Godavari find are estimated at roughly 5 Tcf. Cairn Energy has also reported large finds offshore of Andhra Pradesh and Gujarat. These new discoveries of gas and awareness of the

⁶⁰ U.S. Department of Energy, *An Energy Overview of India* (2003).

⁶¹ Navroz K. Dubash & Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, ECONOMIC AND POLITICAL WEEKLY (Sept. 1, 2001).

advantages of natural gas power plants (such as short gestation and peaking ability) have led to an increase in gas-fired generation companies. The environmental benefits of natural gas, with its absence of sulfur dioxide and lower levels of carbon dioxide and nitrogen oxide compared to coal, also appeal as India becomes increasingly concerned about the environmental impact of energy production.

Through the 1990s, natural gas prices in India were government controlled under the Administered Pricing Mechanism (APM) and limited supply was allocated to states, industries and end users. For domestic gas, the APM ensured that gas prices were held artificially low. In 1997, the Ministry of Petroleum and Natural Gas announced a plan to institute a pricing scheme more in line with international and domestic market realities. The Ministry proposed to price wholesale natural gas in relation to a world market price of a basket of low-sulfur and high-sulfur fuel oils, which are in many cases the substitutes for natural gas. Initially the price of gas was to be 55% of the blended fuel oil price, rising each year until full import parity was reached in 2000.⁶²

When world oil prices spiked in 1999 (*see* Figure 2), the landfall price of gas hit a pre-determined price ceiling of Rs 2850 per thousand cubic meters (approximately \$2 per MMBtu). As a result of the sharp increase in global oil prices, the gas pricing reforms stalled. The prices described above are wholesale rates paid to producers. End consumers incurred additional costs. For example, customers receiving gas through the HBJ pipeline paid a fixed transportation charge, regardless of distance, of Rs 1150 per thousand cubic meters, resulting in a pre-tax cost of Rs 4000 per thousand cubic meters of gas (about \$2.14 per MMBtu). While capped prices in the late 1990s and recent years are roughly in line with domestic production cost, the pricing system is not compatible with the imports of natural gas. The flat pricing scheme created a number of perverse incentives, including inefficient location of gas users. It also failed to provide a means to fund pipeline expansion outside of the state sector. The fixed transport cost, regardless of distance, creates no incentive for users to locate closer to the source. At the same time, the scheme provided inadequate funding to support expansion of the pipeline grid.⁶³ At the present time, as of April 2005, the landfall price of imported LNG in Gujarat is roughly US\$ 3.70, and the cost to consumers is approximately US\$ 4.87 per MMBtu at the coast and up to US\$4.93 per MMBtu if the gas is transported by pipeline outside of Gujarat.

Notwithstanding the new reserves, India's domestic natural gas supply falls short of demand and the country has aggressively pursued plans to increase its ability to import natural gas via pipeline and as LNG. India has invested heavily in LNG terminals and gas pipelines. Gas Authority of India Limited (GAIL), a government-owned enterprise, has worked to double the throughput capacity on its main Hazira-Bijaipur-Jagdishpur (HBJ) Pipeline.⁶⁴ Private companies, such as Shell, have participated in the development of the new natural gas distribution infrastructure. India has increased its import of liquefied natural gas as a partial solution to its expected gas shortage, but overall the electricity sector's financial problems have

⁶² Mark H. Hayes, *India's Natural Gas Sector: Historical Development, Options and Obstacles to Reform, and Supply Alternatives* (2002), unpublished manuscript available upon request from the author (mark.hayes@stanford.edu).

⁶³ Id.

⁶⁴ U.S. Department of Energy, *An Energy Overview of India* (2003).

slowed the growth of natural gas as a fuel source. For example, the payment default of the Maharashtra State Electricity Board to the Dabhol Power Company, an Enron-led IPP, led to many concerns about the financial viability of some LNG import projects and the Indian government froze approvals of new LNG terminals. Several LNG projects were cancelled due to the Indian government's decision not to extend sovereign payment guarantees to power projects, which were slated as the LNG projects' largest customers. Natural gas prices may become cheaper once Reliance Industries' new offshore finds are developed. Efforts are underway to deregulate natural gas pricing, which the government previously handled. The recent domestic finds may promote greater deregulation of prices, forcing LNG importers to compete with domestic natural gas suppliers.

Gas imports into India have received a tremendous boost in 2004-05 with the first deliveries of gas to India's first two LNG terminals. The Petronet Dahej LNG terminal in Gujarat began operations in January 2004 with a capacity of 5 mmtpa. Petronet is initially marketing its gas at \$3.66/mmbtu, which comes to a delivered cost of \$4.87/mmbtu within Gujarat and \$4.93/mmbtu outside of Gujarat.⁶⁵ Despite this high price, Petronet has been able to sell the full extent of its gas.⁶⁶ Petronet also has plans to expand the terminal to 10 mmtpa and is developing a second 2.5 mmtpa facility at Kochi in Kerala.

The Shell Hazira LNG terminal, with a capacity of 2.5 mmtpa, received its first cargo in April 2005. Shell has announced plans to enter into short-term contracts with offtakers to enhance contract flexibility and absorb some price risk from consumers. It has initially signed a contract for 210 days with the Gujarat State Petroleum Corporation (GSPC) for the supply of 0.7 mmscmd at \$3.70/mmbtu while the terminal scales up to full operational capacity.⁶⁷ Shell has been in talks with GSPC to offtake the entire quantity of gas from the facility, but has also been looking to other potential consumers in Gujarat.⁶⁸ The Shell Hazira facility does not have a dedicated LNG supply train, unlike most worldwide LNG terminals in the past, but is expected to source gas from existing LNG trains in Asia operated by Shell and its strategic partner Total Gaz de France.

Currently, some of the most stable projects in India have led the way in securing private gas supply contracts that have two-way take-or-pay provisions, in which the supplier will indemnify the power plant for the costs of failing to deliver. Essar Power and CLP Paguthan, both in Gujarat, have availed themselves of nearby private gas field developments to secure such private contracts and move away from expensive naphtha firing (discussed below).

3. *Naphtha*

Through the 1990s and early years of India's second decade of IPP experience, there was a curious prevalence of power plants developed to fire on naphtha, a fuel that is rarely used

⁶⁵ Sixth Report to the Lok Sabha of the Standing Committee on Chemicals & Fertilizers, April 15, 2005, available at <http://164.100.24.208/ls/CommitteeR/chemicals/6rep.pdf>; The Hindu Business Line, *Shell-Total combine commissions LNG terminal, port at Hazira*, April 22, 2005.

⁶⁶ The Economic Times, *Petronet LNG declines gas supply to NTPC*, April 24, 2005

⁶⁷ The Economic Times, *Royal Dutch/Shell set to invest Rs 3,000 cr for Hazira terminal*, May 18, 2005.

⁶⁸ The Economic Times, *Shell looks at gas-for-equity deals with IPPs*, April 15, 2005.

elsewhere in the world for power generation. Naphtha is a low density, highly volatile liquid fuel that is a byproduct of petroleum refining. It is most commonly used as feedstock for the petrochemical industry. For power generation, however, naphtha is typically an inefficient fuel choice because of its high cost – a fact that led to a temporary crisis for a large number of Indian IPPs and their offtakers when naphtha prices were deregulated in late 1998. During the 1990s, uneven domestic demand for petroleum products, lopsided toward diesel, motor oil and kerosene, created a relative surplus of naphtha in India. Because naphtha was in relatively low demand, in late 1996 the Ministry of Petroleum allocated naphtha and other heavier oil distillates to fuel the proposed 12,000 megawatts of additional power generation capacity that the government had set out to install.⁶⁹ The Planning Commission had advised against this action, arguing that naphtha would entail exceedingly high generation costs per unit and could potentially result in a foreign exchange outflow from heavy naphtha imports.⁷⁰ The IPPs that fired naphtha used combustion turbines capable of burning both naphtha and gas (with some effort required to convert from one fuel type to the other). The PPAs for these projects included dual fuel provisions that allowed the plants to run on naphtha in the event that natural gas was unavailable. According to management at Lanco Kondapalli, the dual-firing generator configuration cost an additional Rs. 1 billion (roughly US\$20 million) for the IPP. IPPs may also incur several million in additional capital costs when converting the dual-firing generator configuration from naphtha to natural gas. Some IPPs in India fired a mixture of natural gas and naphtha simultaneously, such as PPN in Tamil Nadu. In 1998, just as some naphtha burning plants had come online (e.g. Dabhol) and several others were waiting in the wings (e.g. a series of tariff-bid projects in Andhra Pradesh), the government deregulated the price of naphtha. With the price controls removed, naphtha prices doubled in the two years as international prices of crude oil rose.

The tariff for the Dabhol Power Company, which was by far the largest of the dual-firing naphtha/natural gas IPPs, provides a vivid illustration of the impact of soaring naphtha prices on wholesale electricity prices. Dabhol electricity was more than double the cost of power from the average MSEB generator, which was largely attributable to increases in naphtha prices on the international market. At the height of the first naphtha price spike in 2000-2001, the average tariff for Phase I of Dabhol was 4.8 rupees per kilowatt hour. This compared to an average cost of power purchased by the MSEB during this period of 2.2 rupees per kilowatt hour. The high marginal cost of electricity led the MSEB to not dispatch the Dabhol facility under its merit order dispatch rules, which led to a serious decrease in plant load factor (PLF). Low utilization of the plant drove costs even higher under the tariff formula contemplated by the PPA.⁷¹ In Gujarat, the Essar Power IPP weathered the difficulties of running on naphtha in part because the project is primarily captive, providing power to a massive steel plant owned by the project developers. When naphtha prices soared, the steel industry was booming, which allowed Essar to continue profitably operating its power plant. Powergen and CLP's IPP in Gujarat, the Paguthan power plant, however, faced problems with the Gujarat Electricity Board while firing only on naphtha and was hardly generating in the state's merit order dispatch regime. After bringing down the

⁶⁹ Navroz K. Dubash & Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, ECONOMIC AND POLITICAL WEEKLY (Sept. 1, 2001).

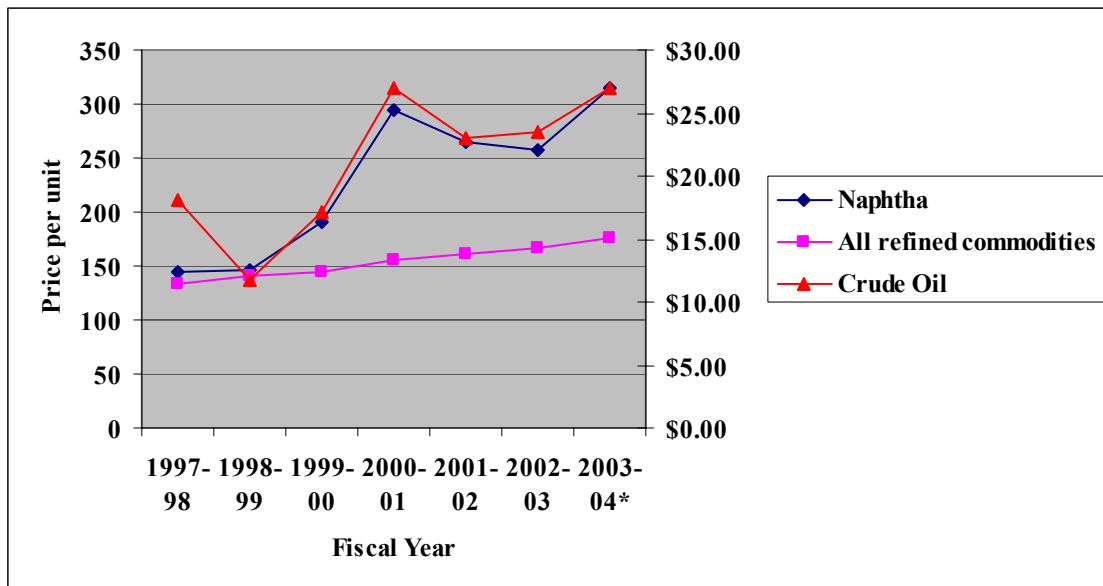
⁷⁰ KP Kannan. N. Vijayamohan Pillai, *Plight of the Power Sector in India: SEBs and Their Saga of Inefficiency*, Working Paper No. 308 (November 2000).

⁷¹ International Energy Agency, *ELECTRICITY IN INDIA: PROVIDING POWER FOR THE MILLIONS* (2002).

tariff by obtaining natural gas fuel linkages, the dispute subsided and the GEBs payment record has improved.

In Andhra Pradesh, pressure from naphtha price increases in the late 1990s also put stress on IPPs. When soaring naphtha prices created a situation in which naphtha-fired facilities would not be fully utilized in the merit-order environment, project companies scrambled to obtain gas allocations in a market of relative gas scarcity. The politics of obtaining gas linkages were used by the government to place pressure on all of the second-generation tariff-bid IPPs in Andhra Pradesh to lower their tariffs. Only the Lanco Kondapalli IPP was able to resist government pressure during the naphtha crisis – a combination of having already closed financing (which would have made tariff renegotiation more cumbersome) and the company’s construction of a pipeline for delivery of gas to the plant.

FIGURE 2: INDIAN NAPHTHA PRICES PER UNIT, 1997-2004.



Sources: Govt. of India, Ministry of Petroleum and Natural Gas; BP Statistical Review of World Energy.

The experience with naphtha, starkly presented in Andhra Pradesh, is repeated with some variations across India. For example, part of the relative stability of the Gujarat plants stems from their success in securing private, commercial and reliable gas supply contracts. The naphtha/gas fired plants in Tamil Nadu (i.e. PPN) have similarly faced pressure because naphtha became prohibitively expensive and projects could not obtain adequate gas linkages to lower their cost. Part of the solution to the problems confronting IPPs in Tamil Nadu may also rest on private gas suppliers – a natural gas project is coming online in the state that will supply PPN with gas, which may make the plant one of the cheapest in the state.

The gradual availability of new domestic and imported gas was critical to solving the naphtha problem, particularly in Andhra Pradesh, where benefits accrued from new gas developments, and in Gujarat, which saw the completion of the Petronet and Shell LNG terminals in addition to newly developed domestic gas fields. The crisis gradually ended in Andhra Pradesh and Gujarat as gas allocations came through, but numerous IPPs took significant

hits during the interim period of skyrocketing naphtha prices as SEBs declined to dispatch electricity from the expensive naphtha-fired facilities and demanded renegotiation of PPAs.

4. *Heavy Distillate Fuel Oil*

India has become a major global market for petroleum products and has gradually reduced its dependence on imports of refined petroleum products. During the 1990s, however, there was far greater demand for distillate fuel oil than could be met by domestic refineries. To make up the shortfall, India imported a large amount of refined products, with the largest volumes in kerosene and distillate fuel oil.⁷²

As part of the Petroleum Ministry's decision on fuel allocations for IPPs in 1996, it also set aside heavy distillates, such as fuel oil, for short-gestation power projects as part of the government's policy to accelerate development of additional generation capacity. Supply of heavy distillate fuel oil, along with naphtha, was not as tight as other refined petroleum products.⁷³ As a result of the Petroleum Ministry policy, four IPPs firing on heavy fuel oil were developed and achieved commercial operation. Three of five operational IPPs in Tamil Nadu were developed with heavy distillate fuel oil as their fuel source (the GMR, Madurai and Samalpatti projects), along with one smaller IPP in Karnataka (the Belgaum project).

TABLE 3: HEAVY DISTILLATE FUEL OIL FIGURES, 1990-2000 (THOUSANDS B/D)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
<i>Domestic output</i>	382	380	373	373	402	450	479	477	511	713	835
<i>Exports</i>	2	1	1	0	0	4	4	0	5	12	44
<i>Imports</i>	87	100	126	155	175	283	277	288	241	136	35

Source: U.S. Department of Energy, Office of Fossil Energy

5. *Nuclear*

The Atomic Energy Commission oversees India's nuclear power industry. India has 14 nuclear reactor units in operation at six facilities with a combined generating capacity of 2720 MW. The wholly state-owned Nuclear Power Corporation operates the plants. India has continued to pursue capacity expansion through nuclear plants, with a series of new nuclear power stations slated to come on line in the new future with reactors utilizing Indian developed design and technology for the first time. During the IPP program of the 1990s, however, nuclear power was not an area of interest for private generation.

6. *Hydro and Renewable*

Hydroelectric power is by far the predominant renewable energy source in India. India's 10th Five-Year Plan calls for 10% of all new electric generating capacity to come from renewable energy sources, which will come almost entirely from additional hydroelectric capacity. About 20% of India's total electricity generation now comes from hydroelectric power

⁷² U.S. Department of Energy, *An Energy Overview of India* (2003).

⁷³ Navroz K. Dubash and Sudhir Chella Rajan, *Power Politics: Process of Power Sector Reform in India*, ECONOMIC AND POLITICAL WEEKLY (September 1, 2001).

plants. The only IPP in India utilizing hydroelectric power is the 86 MW Malana Power Plant in the northern state of Himachal Pradesh.

BOX 1. MALANA POWER HYDRO PROJECT

The 86 MW Malana Project located in Malana Nallah, Himachal Pradesh, is the first and only operational hydro IPP. A diversified Indian industrial group, LNJ Bhilwara, promoted and wholly owns the project. According to reports, some electricity will be wheeled to the LNJ Bhilwara Group's manufacturing facilities in Rajasthan, taking advantage of the new multi-offtaker framework now available in India. The Himachal Pradesh State Electricity Board (HPSEB) and National Power Grid will wheel the power from Himachal Pradesh to Rajasthan. Based on the project's offtake structure, which also benefits from rolling contracts with the Power Trading Corporation (described below), Malana Power illustrates the future potential for, and transition toward, a partial merchant power market in India. For example, in 2001, some of the electricity from Malana Power was sold through the PTC to the Delhi Vidyut Board for distribution in Delhi. An expansion of the Malana hydro station is underway but by different company. For a hydro station, the Malana project was completed with a competitive capital cost of Rs 3.75 per MW and was finished within half of the scheduled construction period. As of January 2001, Malana was selling power at Rs 2.45 per unit. Citing the success of the Malana hydroelectric project, the IFC has provided loans to the LNJ Bhilwara Group for subsequent projects.

D. Institutional Profile

1. *Overview*

Public sector institutions continue to play the dominant role in the generation and supply of electricity in India, primarily through state-level government owned utilities, called state electricity boards ("SEBs") and central sector utilities such as the National Thermal Power Corporation ("NTPC") and the Nuclear Power Corporation of India Limited ("NPCIL"). The central government, through public companies, owns and operates one-third of total generation capacity and interstate transmission lines. At the state level, SEBs own and operate most of the remaining two-thirds of the generation capacity, as well as the majority of intrastate transmission and distribution systems.⁷⁴ Although the central government institutions, particularly after corporatization, have fared better, the SEBs increasingly faced the threat of bankruptcy during the development of India's IPP program in the 1990s. At a time when new generation capacity and distribution infrastructure was desperately needed, the near insolvency of the SEBs created a serious impediment to private investment in the electricity sector. Public funds had also contracted. Without funds to invest in the development of the electricity sector, economic growth far outstripped electricity consumption growth during the 1990s. Despite the opening of generation to IPPs in 1991, the private sector provided less than 10,000 MW of total generation capacity through the 1990s. Through 2003, IPPs accounted for little more than 5000MW of new capacity since the introduction of private participation more than a decade earlier.

Under the Indian constitution, electricity is on the "concurrent list", which means that the states, not the central government, have authority to regulate the electricity sector and determine tariff structures. Although the states, which control the largest percentage of generation and transmission infrastructure and nearly all distribution, form the crucial part in effecting

⁷⁴ International Energy Agency, *ELECTRICITY IN INDIA: PROVIDING POWER FOR THE MILLIONS* (2002).

institutional change, the central government must also play a vital role in guiding the reform process. Within the central government, the Ministry of Power designs and implements electricity sector policies. To this end, the Ministry of Power is responsible for coordinating development and providing the necessary legal and financial incentives for the states to implement reforms. At the state level, various ministries in charge of power or energy make electricity sector policy. Whether state or national in origin, political intervention in electricity matters is common in India. Institutional disagreements and competing agendas between state and federal actors often affect outcomes in India, whether at the project level or sector-wide. Even at the national level, the interrelationship of Indian institutions plays an important role in the development of both policy and particular projects. Fuel-supply issues for power generation projects, for example, may also require clearance from the Ministry of Coal and the Ministry of Railways, or from the Ministry of Petroleum and Natural Gas. The opinions of these various ministries do not always comport with the policies and objectives pursued by the Ministry of Power.⁷⁵

2. *Central Government Institutions*

The Ministry of Power is the central government institution responsible for overseeing India's electricity industry. Several authorities and agencies operate centrally under the Ministry of Power, among them the Central Electricity Authority, which assists the Ministry of Power in technical and economic matters and serves as a central clearinghouse for state-level generation and supply information. Other central government institutions include the Power Trading Corporation, the Rural Electrification Program, which finances rural electrification projects, and the Power Finance Corporation, which provides financing for new power plants and transmission infrastructure. The 1998 Electricity Regulatory Commission Act, in addition to creating state regulatory commissions to regulate retail rates, also established the Central Electricity Regulatory Commission ("CERC"). Like the state-level ERCs, the CERC is an independent statutory body with quasi-judicial powers. The CERC has a mandate to regulate interstate tariff-related matters, advise the central government on formulation of the national tariff policy (which acts only as a rough guideline for the state ERCs), and promote competition and efficiency in the electricity sector.

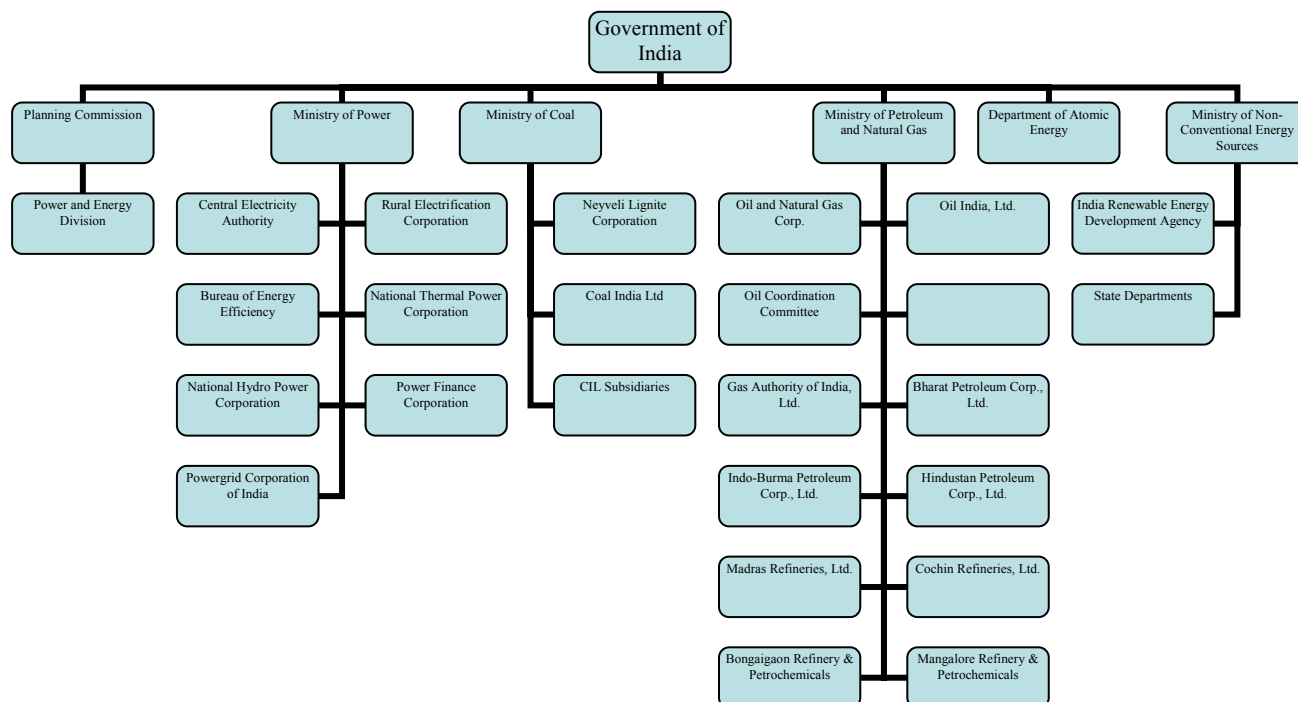
A diverse and often bewildering set of agencies play a role in determining energy policy. These include the Ministry of Petroleum and Natural Gas, the Ministry of Coal, the Ministry of Non-Conventional Energy Sources, the Ministry of Environment and Forests, the Department of Atomic Energy, and, most importantly in the context of IPPs, the Ministry of Power. Within the Ministry of Power, the Central Electricity Regulatory Commission (CERC) works closely with state electricity regulatory commissions, state electricity boards and utilities in power generation, transmission, and distribution of electricity. Other government ministries and agencies have a small hand in energy policy, such as the Ministry of Shipping Transport's responsibility for the importation of energy aboard ships of the state-owned Shipping Corporation of India.

Within the Indian Parliament, the Committee on Energy has primary responsibility for energy-related legislation, and the Energy Policy Division of the Planning Commission establishes federal steering policies concerning energy. Set forth as Table 4 is a schematic

⁷⁵ Id.

diagram illustrating the current relationship between India's various ministries and state-owned companies in the energy sector.

FIGURE 3: STRUCTURE OF CENTRAL ENERGY SECTOR INSTITUTIONS



3. *Central Sector Utilities*

Central Sector Utilities, or CSUs, were introduced in 1975 under the Indian Company Act. Administrative control of the CSUs resided with the central Ministry of Power. The creation of CSUs was premised on the economic advantage obtainable from pooling key state energy resources, such as hydroelectricity and coal, to create economies of scale. CSUs were also designed to complement the SEBs' limited investment capability. Since their recent corporatization, the generation capacity of central sector utilities (such as NTPC) has grown dramatically, representing an increasing share of incremental capacity and now constituting around one-quarter of total capacity.⁷⁶ In the section below on "Dominant Local Competitors in the Electricity Sector," the financial strength and competitive advantages of NTPC are discussed further.

4. *State Electricity Boards*

As mentioned above, every State Electricity Board ("SEB") in India is either unprofitable and/or bankrupt by private sector standards. Just as the first generation of IPPs began to come online in 1995-96, nine of the nineteen SEBs were already in the red. By 2000-2001, the problem had worsened. Every SEB in India was incurring substantial losses and became increasingly

⁷⁶ Tongia (2003); International Energy Agency (2002).

unable to pay for electricity purchased from central public-sector power companies such as NTPC or from IPPs.⁷⁷

Contributing to this budget crisis, cumulative electricity transmission and distribution losses amounted to 260 billion rupees per year, due largely to technical line loss, commercial line loss (electricity theft) and the cross-subsidy tariff structure that heavily subsidizes agriculture at the expense of commercial and industrial consumers, who must pay at rates above the average cost of service. Only slightly more than half of electricity in India is billed, and less than half of electricity consumed is paid for regularly.

An entrenched system of cross-subsidization, encouraged by political interference and buttressed by concerns with equity for rural farmers, has further worsened the financial situation of SEBs. Retail electricity tariffs vary widely according to customer classification. The major customer categories in India are households, agriculture, commercial, industry and railways. Tariffs for households and agriculture are generally far below the cost of service, while tariffs to other customer categories, particularly industry, are typically much higher than the SEBs' average cost of supply. As a result, the average price of electricity sold in 1999-2000 was 26% below the average cost of supply, resulting in large losses incurred by the SEBs.⁷⁸

Financial constraints on SEBs resulting from uneconomic tariff structure and poor collections became the most serious challenge, sometimes insurmountable, faced by IPPs in India. In Section IV below, further detail is provided on the performance of the SEBs that purchased power from IPPs in the four Indian states that form the focus of our India study.

E. Electricity Industry Market Structure

1. *Generation*

The market for generation in India is comprised largely of state-owned power plants, developed and managed by SEBs or unbundled state generation companies or central sector utilities. In 1999-2000, India had a total generation capacity of 113 GW. A decade after the market opened for private generators, IPPs constituted less than ten percent of this total capacity. 15 GW of the total capacity came from captive power plants, discussed below. The fuel mix of the balance consisted of 61 percent coal, 24 percent hydro, 10 percent gas, 3 percent nuclear and 2 percent oil. Coal and hydroelectric power will likely provide the majority of future incremental capacity. Coal power plant efficiency and availability in the 1990s was low by international standards, and many plants used poor quality unwashed coal, with low heat and high ash content. The predominance of coal in the generation market of the 1990s also skewed generation toward base load capacity, with resulting shortfalls in peak period supply, which has continued to be problem with the overall electricity generation market in India.⁷⁹

Due to high commercial and industrial tariffs, power shortages, unreliability, and quality concerns, many Indian corporations have set up their own on-site captive power generation

⁷⁷ International Energy Agency (2002).

⁷⁸ Id.

⁷⁹ Id.

capacity to ensure reliability of power supply. One World Bank study concluded that 76% of Indian businesses depend upon on-site primary or backup electricity generators. Captive generating capacity has grown faster than utility capacity in many cases and has provided an additional 15% to 20% of total capacity since the IPP program began in 1991. Diesel represents the most common fuel for captive power generation, although some larger facilities burn coal or gas. The captive power capacity estimates, already significantly high, exclude the use of countless unregulated smaller generators (so-called “gensets”), numbering in the hundreds of thousands, that typically run off diesel.⁸⁰

2. *Transmission and Distribution*

The transmission network in India currently reaches about 80% of the population. The transmission infrastructure formerly consisted of five regional grids that were not interconnected into a national grid. In 1998, restructuring efforts of the transmission system began with the creation of the Powergrid Corporation. The state-owned Powergrid Corporation is responsible for transmission of about 40% of the electricity generated in India. India has successfully established links between the regional grids.

3. *Dominant Local Competitors in the Electricity Sector*

(a) NTPC

The National Thermal Power Company (“NTPC”) is an enormous player in the Indian electricity sector and has increasingly performed well as a competitive domestic state-owned generating company. NTPC recently launched a successful IPO. The company will likely continue to build upon a number of substantial competitive advantages over IPPs in the generating market.⁸¹

One example of this is a recent security mechanism put in place to protect NTPC receivables from state non-payment. By the early 2000s, unpaid bills to NTPC from the states were becoming unsustainable. A central government committee was set up to study the matter and proposed a one-time settlement: the debt would be converted to state guaranteed bonds, and NTPC would enjoy claw-back rights on any funds moving from the federal government to the state government (i.e., on devolution accounts) to protect payment on these bonds. It remains unclear whether this security mechanism could potentially apply on a going-forward basis to new projects, or even to new receivables that were not securitized in the settlement. Although this appears unlikely, it would afford NTPC an enormous advantage by securing project receivables. In any case, the securitization illustrates the advantages that NTPC will have in the generating market in the future – the backing of the central government means that it will remain less concerned about financial constraints on the SEBs, relatively secure in the knowledge that arrangements of this type will be available through direct central government pressure. At the same time, they will also likely be more flexible than private companies with regards to payment security, offtake terms, and project-specific profitability because of their role as a state owned company.

⁸⁰ Tongia (2003).

⁸¹ Tongia (2003).

However, according to NTPC officials, the firm can account for only about 25-30% of the huge capacity additions that India needs over the next two decades. While some of the balance will be covered by captive power or state-level generation companies, the private sector is still seen as a critical contributor in this process.

(b) Reliance / BSES

The Reliance Group is a family-owned conglomerate regarded widely as “India’s most successful company,” supplying more than five percent of India’s annual exports and accounting for 3.5 percent of Indian GDP with sales of \$18 billion.⁸² 10 percent of the Indian government’s indirect tax revenues depend on the Reliance Group,⁸³ Reliance dominates the Indian petrochemicals market⁸⁴ and has rapidly grown its new energy division, bought out from shareholders of Bombay Suburban Electric Supply (“BSES”). The Reliance Group also has the best access to capital markets of any Indian conglomerate (one of every four shareholders in India holds Reliance shares).⁸⁵ The Reliance Group is viewed throughout India as a trendsetter in corporate culture, with business methods and models distinct from the conservative culture present in India’s traditional family-run conglomerates, such as the Tata Group and Aditya Birla Group. The Reliance Group has also attracted negative publicity relating to allegations from foreign and domestic competitors that Reliance unfairly manipulates government regulators.⁸⁶ Some commentators argue that “India’s public regulatory system would appear to be as open to manipulation as it was during the ‘License Raj’.” With respect to regulatory capture, industry executives claim that “Reliance has no equal in terms of its influence.”⁸⁷

In the energy sector, the newly created Reliance Energy has proclaimed its ambition to dominate the energy market from “well-head to wall socket,” as its chief executive Anil Ambani announced.⁸⁸ At the “well-head,” Reliance Industries in 2002 made a large gas reserve discovery in the Krishna Godavari basin of the Bay of Bengal, offshore from the southern Indian state of Andhra Pradesh. Initial reserve estimates in 2002 were at 7.76 trillion cubic feet. Reliance’s ability to source its own gas could give it a significant competitive advantage over foreign project sponsors. To gain access to the wall socket, Reliance Group acquired a controlling interest in BSES, India’s oldest private electricity distribution utility and one of two private distribution licensees in Maharashtra (the second being Tata Power) in 2003. The Reliance Group took a majority stake in BSES and assumed management control in June 2003 through a successful tender offer, renaming the company Reliance Energy. In addition to its position as the largest electricity distribution company in Mumbai, Reliance Energy has now become the

⁸² Edward Luce & Khozem Merchant, “The family-owned conglomerate has shown it can compete successfully in one global industry after another...” [no article title provided], THE FINANCIAL TIMES, October 21, 2003.

⁸³ *The Show Must Go On*, THE FINANCIAL TIMES, December 2, 2003.

⁸⁴ The petrochemical industry utilizes natural gas to produce certain fertilizers and chemicals. Reliance may see a potential strategic link between its petrochemical division and Dabhol’s LNG port and re-gasification terminal.

⁸⁵ *The Show Must Go On*, THE FINANCIAL EXPRESS, December 2, 2003.

⁸⁶ Luce & Merchant, “The family-owned conglomerate has shown it can compete successfully in one global industry after another...”

⁸⁷ *Id.*

⁸⁸ *BSES is now Reliance Energy – To set up transmission, trading arms*, HINDU BUSINESS LINE, June 10, 2003.

dominant electricity distribution player in New Delhi following the unbundling and privatization of the New Delhi electricity board.⁸⁹

The Reliance Group in the past has excelled as a first mover in sectors with uncertain regulatory environments, such as the one created by the 2003 Electricity Act. Reliance has made clear its intention to move directly to consumer markets in the newly deregulated electricity market. Reliance Energy's control of large distribution franchises, its intention to continue expansion of its generation and distribution capabilities, its access to gas fields and existing infrastructure, and its proven ability to overcome Indian regulatory hurdles make it a potentially fierce domestic competitor in the IPP market.

(c) Tata Power

Whereas BSES/Reliance Energy had its start in Mumbai as a distribution licensee, Tata Power finds its origins in the early 20th century as a Mumbai generation licensee. Since then, Tata Power has grown into India's largest private sector power generating company after consolidating three independent private utilities. For its 2004 fiscal year, Tata Power booked net revenues of Rs. 4239 crore (approximately US\$870 million). In Mumbai, where Tata has the strongest foothold and has served customers for nine decades, the company supplies electricity to the metropolitan railway network, refineries, ports, BEST and Reliance Energy Limited. In addition to generation capacity in Mumbai, Tata owns power plants in Jharkhand (under development) and Karnataka.⁹⁰ The company was criticized during the 1990s for its reluctance to enter into the IPP business, but its former managing director, AJ Engineer, described this as a "blessing in disguise."⁹¹ Tata's foray into IPPs was limited to the 81 MW Belgaum power plant in Karnataka, which was commissioned on schedule and performing well according to reports. With the benefit of experience at the company and in the electricity sector as a whole, Tata has started to pursue IPP development more aggressively. In addition to vying for a stake in the revived Dabhol plant, Tata is in the midst of construction of a 240 MW IPP in Jojobera, Jamshedpur. Tata currently has an installed power generation capacity of more than 2200 MW (but with nearly 80% concentrated in the vicinity of Mumbai) and a growing presence in transmission and distribution as well as distribution. As of 2003, Tata planned to add 1500 MW to its generation capacity by 2009, far less aggressive than the 9000 MW that Reliance plans to build by 2012.⁹² According to company reports, Tata's transmission and distribution losses of 2.4% are among the lowest in the country. Tata was also engaged in India's first transmission project to be executed with a private-public partnership since the enactment of the 2003 Electricity Act. The project will wheel surplus power from Bhutan to power deficit states in northern India. Like Reliance, Tata Power has clearly taken steps to cash in on the opportunities presented by the 2003 Electricity Act and, although less aggressive in its outward strategy, will be a dominant player and significant local competitor among foreign and domestic IPPs.

⁸⁹ *Reliance Stake drops to 53% of BSES*, THE ECONOMIC TIMES, December 3, 2003; Luce & Merchant, "The family-owned conglomerate has shown it can compete successfully in one global industry after another..."

⁹⁰ Tata Power Company Profile, available at <http://www.tatapower.com>.

⁹¹ Interview with AJ Engineer, Managing Director, Tata Power (date not specified), available at http://www.tata.com/0_media/features/interviews/20020515_adi_engineer.htm.

⁹² Business Standard, *India Inc's on an investment drive* (2003).

In addition to the domestic conglomerates and state-owned companies that operate across India, there are a number of important regionally powerful companies in electricity generation, such as GVK and Lanco in Andhra Pradesh, Essar Steel in Gujarat, and GMR in Tamil Nadu and Karnataka.

4. *Domestic Turbine Suppliers*

As one of the only developing countries in the world with its own power turbine manufacturing industry, India had the ability to supply its own equipment for power generation (although its gas turbines were still considered technologically obsolete during the 1990s IPP buildout).

IV. INDIA'S IPP EXPERIENCE

A. Introduction: The Universe of Greenfield IPPs in India

Despite a rapid expansion of power generation (from 1300 MW in 1947 to 113,506 MW in 2004),⁹³ shortfalls in electricity supply have continued to constrain India's economic growth severely. Since 1991, India has turned to the private sector to address the supply gap. According to a recent OECD roundtable, private power plants have contributed commissioned capacity of roughly 7400 MW through 37 IPPs. The Central Electricity Authority's dispatch records and comprehensive data searches suggest that this overestimates the amount of power actually provided by IPPs. The Ninth Plan cites 5,061 MW of additional power capacity provided by the private sector through 2001-02, which is much closer to the estimate of roughly 5200 MW of IPP capacity in PESD's universe of Indian IPPs (not including projects classified as IPPs but structured as cooperatives). According to the OECD, eleven new IPPs, totaling 4000 MW of capacity, have achieved financial closure since the passage of the 2003 Electricity Act.⁹⁴ However, despite the great sense of urgency to increase power generation capacity in the 1990s through foreign investment, IPPs were only producing 2.7% of the capacity that was originally slated for private participants by 2000. Table 4 below sets forth the universe of greenfield IPPs that achieved commercial operations from the launch of India's IPP program through 2003.

⁹³ OECD India Investment Roundtable, *Opportunities & Policy Challenges for Investment in India: Background Paper* (October 19, 2004).

⁹⁴ *Id.*

TABLE 4: UNIVERSE OF INDEPENDENT POWER PRODUCERS IN THE INDIAN POWER SECTOR

Project Company Name	State	Fuel Choice	MW	Fast Track?
GVK Power	Andhra Pradesh	Natural Gas / Naphtha	216	YES
Spectrum Power Generation	Andhra Pradesh	Natural Gas / Naphtha	206	YES
Lanco Kondapalli Power	Andhra Pradesh	Natural Gas / Naphtha	350	No
BSES/Reliance Andhra Power	Andhra Pradesh	Natural Gas / Naphtha	220	No
Andhra Pradesh Gas Power*	Andhra Pradesh	Natural Gas / Naphtha	172	No
Gujarat Paguthan Energy	Gujarat	Natural Gas / Naphtha	655	No
Essar Power	Gujarat	Natural Gas / Naphtha	515	No
GIPCL Baroda Unit I**	Gujarat	Natural Gas / Naphtha	145	No
GIPCL Surat Unit**	Gujarat	Lignite Coal	250	No
GSEG Surat Unit**	Gujarat	Lignite Coal	156	No
PPN Power	Tamil Nadu	Natural Gas / Naphtha	330.5	No
GMR Power (Basin Bridge)	Tamil Nadu	Heavy Distillate Fuel Oil	200	No
ST-CMS (Veyneli)	Tamil Nadu	Lignite	250	YES
Balaji Power (Madurai)	Tamil Nadu	Heavy Distillate Fuel Oil	106	No
Samalpatti Power	Tamil Nadu	Heavy Distillate Fuel Oil	106	No
Dabhol Power	Maharashtra	Phase I: Naphtha / Distillate Phase II: Natural Gas (incomplete)	740 [1444]	YES
Belgaum Power	Karnataka	Heavy Distillate Fuel Oil	81	No
Jindal Tractebel Power	Karnataka	Blast Furnace Gas / Coal	260	No
Tanir Bavi Power	Karnataka	Naphtha	220	No
Jamshedpur Power	Jharkhand	Coal	307.5	No
Malana Power	Himachal Pradesh	Hydro	86	No
BSES(Kerala)	Kerala	Natural Gas / Naphtha	173	No
Small IPPs (< 50 MW; 9 total)			182	No
Total Installed Capacity:			5927	MW
Total Installed Capacity Minus Cooperatives:			5204	MW
* Project development predated IPP policy; structured as a cooperative with % of capacity dedicated to SEB				
**CEA approved as IPPs; structured as cooperatives.				

B. National IPP Strategy

Indian policymakers cite two primary justifications for relying on the private sector to address supply electricity shortages. First, India's power shortage had placed serious constraints on the overall growth of India's economy. When the Indian government began to explore an IPP strategy, industry and transportation accounted for 70% of India's power consumption and officials feared the repercussions of continued power shortages for India's program of development.⁹⁵ Second, a move away from the state utility model was believed to be necessary to reduce state expenditures and enormous budget deficits in the energy sector. The ever-increasing demand for electricity had outpaced the growth in public funds required to finance capacity expansion. Indian policymakers have long viewed the poor quality and inefficient pricing of electricity through a cross-subsidy tariff structure as the single greatest deterrent to

⁹⁵ HARVARD BUSINESS SCHOOL, ENRON DEVELOPMENT CORPORATION: THE DHABHOL POWER PROJECT IN MAHARASHTRA, INDIA (A) (HBS Case no. 9-596-099, Mar. 25, 1997) [hereinafter HARVARD CASE STUDY (A)].

India's economic growth and development. As a result, Indian legislators at the central and state level had made the electricity sector a focal point of economic policy and regulatory reform.

In 1991, the Indian government also issued its "mega power project" guidelines, which provided incentives for qualifying thermal power plants with capacity in excess of 1000 MW or hydroelectric power plants with at least 500 MW capacity. In addition, the plants had to supply power to more than one state. Under the guidelines, mega power projects were exempt from customs and countervailing duties, among other lesser investment incentives.

The regulatory arrangements applied to IPPs have also differed considerably, particularly when comparing the eight projects approved under the "fast-track" program and the remaining projects pursued according to terms and procedures somewhat less favorable to foreign investors. This included both cost-bid and tariff-bid projects, which unsurprisingly led to considerably lower construction costs compared to projects developed without competitive bidding. Although early reforms focused on IPPs, private sector power currently represents only roughly five per cent of total capacity in India. The main supplier of new electricity through the 1990s was the state-owned thermal power company NTPC, which amassed enough capacity to make it the sixth largest generating company in the world.⁹⁶ NTPC is by far the largest electricity producer in India, with more than 20,000 MW of installed capacity. Despite India's series of reforms and policy intentions, the electricity sector remains heavily dominated by the state.

C. Legal Regime for IPPs

As a central component of India's structural adjustments and efforts toward economic liberalization in the early 1990s, the federal government's Ministry of Power announced that India would open its state-owned electricity sector to foreign investment. In 1991, the federal parliament passed amendments to the Electricity Supply Act, 1948 ("ESA") to allow 100 percent foreign private ownership of generating plants. The 1991 Amendments adopted a "cost-plus" approach to India's newly created independent power producer ("IPP") program, providing for a guaranteed return on equity of at least 16 percent, a five-year tax exemption, and other attractive investment incentives.⁹⁷ To provide context to the current legal regime for private investment in the electricity sector generally and IPPs specifically, the sections below summarize the primary legislation addressing the electricity sector, followed by discussion of the 1991 Amendments and subsequent reforms culminating in the 2003 Electricity Act.

1. *The Indian Electricity Act, 1911 and Electricity Supply Act, 1948*

Because electricity falls under the concurrent list of responsibilities in the Indian Constitution, both state and central governments may exercise legislative powers on matters of electricity policy. Similar to other areas in the Indian constitution dealt with concurrently at the

⁹⁶ Tongia (2003).

⁹⁷ Navroz K. Dubash, *India: Electricity Reform under Political Constraints*, in POWER POLITICS: EQUITY AND ENVIRONMENT IN ELECTRICITY REFORM (Navroz K. Dubash ed., World Resources Institute 2002); SHARON BEDER, POWER PLAY: THE FIGHT TO CONTROL THE WORLD'S ELECTRICITY (2003); ABHAY MEHTA, POWER PLAY: A STUDY OF THE ENRON PROJECT (2000); D'Sa, Narsimha & Amulya, *India's Power Sector Liberalization: An Overview*, ECONOMIC AND POLITICAL WEEKLY, June 5, 1999.

state and federal level, federal rules and legislation will often override state-level decisions.⁹⁸ Two legislative acts, one before and another immediately following Independence, forged the development of the power industry in India. The Indian Electricity Act, 1910 (the “IEA”), introduced the licensing system in the electricity industry, and the Electricity Supply Act, 1948 (the “ESA”), provided for state involvement in the industry under the new federal constitutional system. The IEA was enacted at a time when the electricity industry was heavily fragmented, competitive and concentrated heavily in urban areas.⁹⁹ In an attempt to impart structure on the infant industry, the IEA primarily addressed the supply and use of electricity under an ad hoc regime of private licensees. The subsequently enacted ESA moved India toward a state-dominated system by laying out the statutory powers and functions of the Central Electricity Authority, powerful vertically integrated state electricity boards and state generating companies. One of the fundamental reasons for the enactment of the ESA was to use state control to achieve electrification of rural and semi-urban areas.¹⁰⁰

The 1956 Amendment to the ESA increased the supervisory control of state governments over the SEBs. The resulting politicization of the SEBs led to massive electricity subsidies in important sectors like agriculture, and substantial operating losses among the SEBs became the norm. Due to the poor financial health of the SEBs and the widening gap between electricity demand and supply throughout India, the ESA was again amended in the 1970s to allow participation of the central government in power generation through large-scale projects that serve more than one state. Because large-scale projects were financially out of reach for the SEBs, central leadership in this area led to the creation of successful federal generating companies like the National Thermal Power Corporation (“NTPC”) and the National Hydro Power Corporation (“NHPC”), which now act as significant players in the power industry and may operate as competitors to IPPs in an open access retail regime. Currently, Maharashtra is relying in part on NTPC to expand its generation capacity. Under amendments to the ESA, captive generation was also allowed under certain narrow circumstances in order to reduce demand-supply gaps.¹⁰¹

2. *The Electricity Act Amendments of 1991*

Similar to world trends and activity in other Indian business sectors, the electricity sector began to open up to private participation and foreign direct investment in the early 1990s through further amendments to the ESA and IEA. Under the 1991 Amendments, independent power producers (“IPPs”) were granted attractive terms to set up power stations and sell electricity to the vertically integrated SEBs through long-term power purchase agreements (“PPAs”). Because project promoters had to work with SEBs, they tended to converge on the better performing SEBs, but even top performers such as the MSEB were severely limited in their ability to make credible long-term commitments in light of their future earning capacity and longstanding operating losses. In the mid-1990s, some states independently promulgated reform acts to restructure their electricity supply industry by de-integrating the SEBs into

⁹⁸ Tongia (2003).

⁹⁹ Subhes C. Bhattacharyya, *Review of the Electricity Act 2003 of India*, Center for Energy, Petroleum and Mineral Law and Policy, Dundee University, November 2003.

¹⁰⁰ Tongia (2003)

¹⁰¹ Bhattacharyya (2003)

separate generation, transmission and distribution systems. All the reform acts instituted a single buyer industry structure, where the transmission and bulk supply licensee acted as the buyer of all electricity produced by generators and then in turn sold electricity to distribution licensees for final sale to consumers. Because Maharashtra did not pass its own reform act, I have omitted further discussion of the different state-level experiences with de-integration and deregulation.¹⁰²

3. *The Electricity Regulatory Commission Act, 1998*

Although subsequent amendments were made to the ESA, it was the Electricity Regulatory Commissions Act (the “ERCA”) in 1998 that made the first serious attempt to distance the government from the functioning of the SEBs. Under the ERCA, independent electricity regulatory commissions (“ERCs”) were created at the central level and the framework provided for voluntary creation at the state level – respectively, the Central Electricity Regulatory Commission and the State Electricity Regulatory Commissions. The ERCA sought to rationalize electricity tariffs, eliminate subsidies, provide for greater transparency in policy formulations, and promote both private sector participation and efficient and environmentally sound policies.¹⁰³ The scope of the ERCA, however, was limited, because it did not require legislation at the state level and was not preceded by restructuring of the electricity supply industry.

4. *The Electricity Act, 2003 and Implications for IPPs*

The Electricity Act 2003 (the “Act”), which became effective in mid-June 2003, consolidates and replaces the Indian Electricity Act, 1910, the Electricity Supply Act, 1948 and the Electricity Regulatory Commission Act, 1998.¹⁰⁴ By addressing certain issues that have prevented or slowed down the reform process, the Act seeks to usher in second generation reforms of the Indian power sector following the first round of reforms under the 1991 Amendments and the Electricity Regulatory Commissions Act, 1998. The Act sets forth a structure and broad guidelines for mandatory changes directed toward establishing a competitive market in the electricity sector through the removal of key restrictive barriers. At core, the Act embodies principles that will move the industry structure from a single-buyer market to a multi-buyer, multi-seller system.

The Act eliminates licensing requirements for electricity generation, as well as the techno-economic clearance previously required from the CEA for new generating facilities.¹⁰⁵ Generators can sell electricity to any licensee (with the exception of transmission licensees, which are not allowed to trade in electricity) and, if state ERCs have implemented full retail

¹⁰² For further background on state-level experiences with de-integration and deregulation, see Tongia (2003).

¹⁰³ See, generally, Pramod Deo, *Setting Tariffs for Economic Efficiency, Equity and Environment Externalities – the Maharashtra Experience*, April 2003 (paper presented at the Workshop on State-Level Electricity Reforms: Impacts on Technologies, Institutions and Environment, Indian Institute of Management, Ahmedabad).

¹⁰⁴ *The Electricity Act, 2003*, Universal Law Publishing Co. Pvt. Ltd. (New Delhi, 2003) [hereinafter, “EA 2003”], at 4. The Act was originally published in the Gazette of India, Extra., Part II, Section 3(ii), 10 June 2003), available at http://powermin.nic.in/The%20Electricity%20Act_2003.pdf.

¹⁰⁵ The one exception is hydro-electric power stations above a certain level of capital investment. EA 2003, Section 8.

distribution, to consumers directly. Because the Act provides for direct sale of electricity by generators with “non-discriminatory open access” to end consumers, it aims to promote participation from IPPs upon implementation by the state ERCs.¹⁰⁶ IPPs should be more attracted to a multi-buyer system because it provides more creditworthy offtaker alternatives compared to the single-buyer SEB model. One negative factor for IPPs will be the imposition of a surcharge by the State ERC (if the sale is intra-state) or Central (if the sale is inter-state) ERC, designed to compensate for the loss in cross-subsidy revenues to the SEBs due to the anticipated direct sale of electricity by generators to the most lucrative creditworthy consumers (which paid the highest tariffs under the cross-subsidy system). Section 9 of the Act removes restrictions on the construction and operation of captive power plants by any consumer or group of consumers, which opens further opportunities for private sector competition.¹⁰⁷ Prior to enactment of the Act, captive power generation generally required approval from the SEB or state regulatory commission based on (i) whether the SEB could provide power at costs lower than the consumer’s cost of generating its own captive power, and (ii) whether the SEB was able to supply the power demanded by the consumer at the required times. If the SEB was able to meet both of these provisions, it could reject the customer’s proposal to generate its own captive power. Removing entry barriers to captive generation and adding the possibility of alternative buyers will likely subject the SEBs to even greater financial stress. In particular, the new generation structure will eat into cross-subsidies and erode the SEBs’ most reliable segment of paying customers.

The Act also provides exemption from the surcharge for wheeling of power (as opposed to sale), providing even greater financial incentives to companies and groups of companies interested in providing their own supply of electricity to different locations and exiting the grid. It is important to note, however, that sale of excess power from captive power facilities still requires the approval of the appropriate commission under the Act.¹⁰⁸ Because the Act provides significant new freedoms for captive power, merchant power through captive generating units will likely become a key driver of growth in capacity in the future and represent competitive threat to existing IPPs. There is concern that proliferation of grid-connected captive power plants may lead to system instability, grid management problems and an attendant increase in disputes over power transmission and sales. The World Bank is among those viewing grid discipline as one of the major transitional issues. It is unclear whether the emerging open access electricity market will in fact force IPPs to bear some of the increased grid stability risk in the new deregulated environment.

The “competitive bidding” limitation would also presumably apply to other fast track IPPs, potentially creating a stranded costs issue for project sponsors if the tariffs under their PPAs are revised under the new law. While the Act eliminates barriers to entry, the state ERC or central ERC still determine the tariff for a generator’s sale of electricity to any distribution licensee.¹⁰⁹ The Central ERC has jurisdiction over central generators (such as NTPC power plants) and generators that sell electricity in more than one state. The state ERCs have authority to regulate generators within the state’s boundaries, except those falling under Central ERC

¹⁰⁶ See EA 2003, Section 42(3).

¹⁰⁷ See EA 1998, Section 9.

¹⁰⁸ See EA 1998, Section 9.

¹⁰⁹ See EA 2003, Section 62(1)(a).

jurisdiction. To prevent some IPPs from incurring stranded costs, the Act requires the ERCs to maintain tariffs at previously agreed levels for projects selected through a “transparent process of bidding” (which excludes projects such as Dabhol). The regulatory regime contemplated by the Act gives a great deal of power and autonomy to the now mandatory state electricity regulatory commissions (“ERCs”), and employs a multi-year approach and flexible timeline. The authority of ERCs to set tariff levels also remains intact, although the Act contemplates a National Tariff Policy, still being finalized, that will serve as a guide to ERCs. The Act introduces important changes to tariff determination principles compared to the previous rate-of-return regulation required under the ESA. The Act does not keep in place mandatory rate-of-return tariff regulation and gives the ERCs freedom to use a range of approaches to fix tariffs. Because the ERCs will have broad discretion in setting tariffs and determining cross-subsidy levels, there is also no foreseeable end to differences in the regulatory treatment of central, state and private generators, as was the case in the past. Open access to interstate transmission lines as mandated by the Act was implemented by an order issued by the Central Electricity Regulatory Commission on November 17, 2003. The order stated that “all transmission service providers in the country, including Powergrid shall provide non-discriminatory open access for inter-state transmission to any distribution company, trader, generating company, captive plant or any permitted consumer with immediate effect.”¹¹⁰ For investors in IPPs, the ability of generators to sell electricity at mutually agreed rates to consumers with full or partial retail choice (thus bypassing tariff regulation by the ERC) stands as a promising opportunity for the future but is by no means guaranteed in the near term by the Act. Under Section 12(c), the Act designates electricity trading as a licensed activity and defines trading as the “purchase of electricity for resale.”¹¹¹ In keeping with its combined treatment of wholesale and retail distribution activities, the Act does not make a distinction between wholesale trading (involving power purchases from generation companies and sale to distribution licensees) and retail trading (involving power purchases from generation or distribution licensees for sale to end consumers), which renders some of the licensing requirements for traders unclear. Of course, investors in IPPs will hope that the regulatory landscape for energy traders will take shape in a way that opens new opportunities for the dispatch of its electricity to a wider range of end consumers through energy trades. Penalties for theft of electricity have also increased under the Act, which seeks to curtail heavy transmission and distribution losses throughout the country.

The power of the government, through the ERCs, to take over core industrial assets and utilities when extraordinary circumstances arise in the public interest is not a novel concept in India and has been exercised repeatedly by other sovereign states, including the United States, in purported times of crises. However, the express provisions for seizure of assets in the public interest in the Act will cause concern to investors in IPPs because of the broad power it gives to the three-person state ERCs. Prior to the 2003 Electricity Act, the financial health of the intermediary state electricity board in the single buyer market structure proved to be a key variable. The changes contemplated by the 2003 Electricity Act are ambitious in their scope and will undoubtedly have a major impact on the future of IPPs. The Electricity Act seeks to remove the weak link of SEBs in the supply chain. Implementation of the law is largely left to the states, particularly the state commissions, and there is still no fixed time frame or strict guidelines for elimination of cross-subsidies, disintegration of the monolithic state utility boards, and

¹¹⁰ *Indian regulation opens access to state-owned transmission lines*, GLOBAL POWER REPORT, Dec. 11, 2003.

¹¹¹ See EA 2003, Section 2 & Section 12(c).

introduction of wholesale and retail competition. As a result, the Act will require considerable political will before tangible benefits accrue for the energy sector. If successfully implemented, the new multi-buyer model created by the Act will allow IPPs to look beyond selling to the financially distressed SEBs and choose among multiple creditworthy offtakers.

For existing IPPs to profit in the new open access environment, future infrastructure investment in the electricity sector needs to be less skewed toward generation. The benefits available under the Act to a massive project like DPC will only be fully realized with substantial expansion of the transmission capacity. Finally, new investors in DPC should be troubled by uncertainty regarding the manner in which MERC will determine the tariff levels, cross-subsidy surcharges and wheeling charges required for dispatch of electricity to the new multiplicity of users. One hopes that budding regulatory institutions charged with heavy responsibilities in the deregulated electricity sector will avoid capture and introduce greater certainty and economic efficiency into the market. Moreover, open access transmission will ideally lead to better transmission infrastructure, remove the old emphasis on capacity expansion, and place new emphasis on least cost alternatives.

D. Selected State IPP Experiences

1. *State of Maharashtra*

(a) Electricity Sector and State Electricity Board

The MSEB operates as one of the largest SEBs in India (and the largest as of 2002-03), with nearly 13,000 MW of capacity on its grid as of 2002-03 (including 728 MW of offline capacity from the Dabhol Project), with 9771 MW of that capacity owned and operated by the MSEB.¹¹² Private generation capacity in 2002-03 represented only a 12 percent increase in total state-wide capacity on the grid since 1996-97. The MSEB's own capacity increased 26 percent over this same six year period.¹¹³ During the late 1990s, the MSEB depended less on power purchases from outside sources than other states because of its relatively high ownership of overall capacity in Maharashtra. Tata Electric Company (now Tata Power) and the Bombay Suburban Electric Supply Company (now Reliance Energy) have also provided additional capacity to the grid through licensed generating units. The MSEB does not distribute electricity in the state capitol of Mumbai, which is served by Reliance Energy, Bombay Electricity Supply and Transport (BEST), and Tata Power. Coal fuels most of the generation capacity owned by the MSEB, and the vast majority of the Board's plants are thermal. According to the Ministry of Power, the reported peak shortage in 1996-97 was only 8.7 percent, relatively low compared to peak shortages elsewhere in the country.¹¹⁴

¹¹² MSEB Annual Administrative Report, 2002-03, at 4.

¹¹³ Infrastructure Development Finance Corporation Policy Advisory Papers, *State Electricity Boards: A Selective Overview* (1998); MSEB Annual Administrative Report, 2002-03.

¹¹⁴ Infrastructure Development Finance Corporation Policy Advisory Papers, *State Electricity Boards: A Selective Overview* (1998).

Through the 1990s, the MSEB had a reputation as one of the best managed SEBs in the country.¹¹⁵ In 2002-03, the MSEB reported its peak demand at 13,418 MW, which outstripped its ability to supply, particularly when factoring in the several thousand megawatts of load shedding occurring at the time of peak demand.¹¹⁶ The MSEB's average plant load factor for 2002-03 was 72 percent according to MSEB data.¹¹⁷ In its 2002-03 Administrative Report, the MSEB states that special efforts were directed toward enhancing computerized billing, increasing the efficiency of its power plants through improving operations and maintenance, and raising capital through external assistance and financial institutions.¹¹⁸

(b) The Dabhol Project

One of the first major developments spurred by the 1991 Amendments was a memorandum of understanding hastily signed in June 1992 between Enron Development, the wholly-owned subsidiary of Houston-based energy concern Enron Corporation,¹¹⁹ and the west Indian state of Maharashtra, India's most industrialized and prosperous state.¹²⁰ Just five days after the initial arrival of Enron's executives in India, Enron and the Maharashtra State Electricity Board ("MSEB") had already agreed to the principal terms that would underlie the largest commercial contract in Indian history, as well India's largest foreign investment to date.¹²¹

The Dabhol Power Company ("DPC") became India's first and largest fast-track IPP. Prior to the first renegotiation in 1996, Enron maintained majority control with an 80 percent stake and the MSEB did not hold an equity stake in the project.¹²² The additional equity participants were General Electric, which supplied and installed the plant's turbines, and Bechtel, which acted as the primary contractor for the engineering, procurement and construction of the plant. General Electric and Bechtel each held a 10 percent stake in DPC through their subsidiaries, Bechtel Enterprises and GE Structured Finance.¹²³

Numerous factors contributed to the renegotiation and eventual mothballing of the Dabhol project. These factors included: (i) a PPA with terms that were exceedingly unbalanced in favor of the project company; (ii) host country payment obligations that became viewed as

¹¹⁵ Id.

¹¹⁶ MSEB Annual Administrative Report, 2002-03.

¹¹⁷ Id.

¹¹⁸ Id.

¹¹⁹ Enron Corporation was a diversified energy company that booked net earnings of \$453 million on revenues of nearly \$9 billion in 1995. Like other energy market players at the time, Enron confronted the problem of sluggish growth in the U.S. energy sector with a strategic decision to focus heavily on the growing demand for power in developing countries. In pursuit of this strategy, Enron Corporation created Enron Development Corporation to exploit power generation opportunities in high-growth emerging markets. See Salacuse,

¹²⁰ The State of Maharashtra was India's third largest state with a population of nearly seventy-nine million people. Centered around the Indian commercial capital of Bombay (later to be Mumbai), Maharashtra also boasted the highest gross national product per capital in India. Jeswald Salacuse, *Renegotiating International Business Transactions: The Continuing Struggle of Life Against Form*, INTERNATIONAL LAWYER (Winter 2001).

¹²¹ Salacuse (2001)

¹²² Id.

¹²³ Id.

exploitative by the public and in any case were not sustainable due to the financial condition of the MSEB; (iii) an unusually high return on equity guaranteed under the project documents; (iv) an unanticipated level of political risk; (v) the appearance of government impropriety and allegations of corruption; (vi) the initial exclusion of domestic partners; (vii) an unstable industry structure at the state and national level; (viii) and exogenous events such as the collapse of Enron Corporation.

2. *State of Andhra Pradesh*

(a) Electricity Sector and State Electricity Board

The Andhra Pradesh electricity sector emerged as a leader in reform efforts during the 1990s. Relative to other SEBs, the state utility has maintained a positive, if not stellar, performance record. Andhra Pradesh has recently ranked number one in independent reviews of state power sector performance.¹²⁴ In 2000, installed capacity in Andhra Pradesh had reached almost eight gigawatts and per capita consumption was 391 kilowatt hours, compared to 355 kilowatt hours on average in India. Hydropower and coal fired plants account for the majority of the generating capacity in the state, although dependence on combined cycle natural gas-fired projects has grown tremendously, primarily via the installation of private generators.

In 1998, the Andhra Pradesh unbundled its SEB into a generation company, APGenco, and a transmission and distribution company, APTransco, which also acts as the offtaker from IPPs. APTransco was further divided into a transmission company and four distribution companies in 2000.¹²⁵ Genco controls roughly 70% of installed capacity, with the rest coming from IPPs, cooperative power projects and captive generators. Technically, performance is mixed—the generation sector in Andhra Pradesh has averaged the highest plant load factors in India, but the transmission and distribution sectors often fritter away any potential gains with high losses and poor billing performance. Tariffs remain highly cross-subsidized, with prices for industry among the highest in India, yet almost non-existent for agriculture (e.g. in 1997-98, agricultural users accounted for 48% of sales, yet only 4% of revenue).¹²⁶

Policymakers in Andhra Pradesh sought to place the state's electricity sector at the vanguard of reform in India. The state was an enthusiastic participant in the early development of IPPs—two of the original eight fast-track IPPs (GVK and Spectrum) are in AP, both of which achieved commercial operations. In 1998, the state passed an electricity reform law that unbundled the state electricity board into generation and transmission units, and established an independent regulator.¹²⁷

(b) Andhra Pradesh IPP Overview

¹²⁴ Government of India, Ministry of Power, *Rationale for Andhra Pradesh State Power Sector Scoring* (2003); CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

¹²⁵ Id.

¹²⁶ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998)

¹²⁷ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Andhra Pradesh, India*, PESD Working Paper #20 (2004).

Development of IPPs in Andhra Pradesh proceeded in three stages. First, in the early 1990s the state pursued fast-track MOU projects (GVK and Spectrum), which were priced on a cost-plus basis and did not involve a formal competitive bidding process. Second, Andhra Pradesh invited project cost bid projects, in which project sponsors competitively bid on project cost pursuant to guidelines established in January 1995 – none of these has ever reached operations. Third, and most recently, Andhra Pradesh has solicited tariff bid projects, in which the sponsors bid a fixed tariff formula and then proceeded to negotiate a PPA with AP Transco.¹²⁸

There are five projects operating in Andhra Pradesh currently, which include GVK (MOU), Spectrum (MOU), Lanco Kondapalli (tariff bid) and BSES/Reliance (tariff bid).¹²⁹ Although the fifth operational project, Andhra Pradesh Gas Power, is classified as an IPP in government records, the project's development actually predated the national IPP policy. The sponsor's structured the project as a cooperative, with the AP SEB (now AP Transco) participating as a promoter and taking its proportional share of capacity.¹³⁰

From the perspective of the host government, the IPP experience in Andhra Pradesh invoked either negative or mixed views. First, in terms of price, we hear conflicting reports regarding the construction cost of the three main IPPs. However, the IPP share of total capacity is still small enough that the burden appears to have been bearable, and the competitiveness of the IPPs from the host government perspective has improved as the sector has matured. Nonetheless, although Andhra Pradesh has been among the most successful states in attracting and maintaining investment in private generation, from the 1990s to the current time state officials in Andhra Pradesh have expressed reservations about the role of IPPs in the state, citing the expensive cost of electricity from IPPs, relatively high fixed costs when measured against the debatable benchmark of NTPC or state generation company plants of like vintage and configuration, and what is deemed an unreasonably high rate of return provided to IPPs given the risk profile of the state. APTransco, for example, asserts that the security mechanisms in place, particularly escrow arrangements, effectively tie its hands and guarantee payment security for IPPs in Andhra Pradesh. Moreover, the wholesale cost of electricity from state or central generating companies in Andhra Pradesh, is considerably lower, due to lower fixed costs, concessionary financing, and hidden subsidies (although state officials argue that the cost comparison of government and private generation is transparent, on equal terms, and not skewed by supposed subsidies). PESD has begun to investigate this debate in detail. However, the forensic and investigative accounting required to determine with precision the true cost comparison of state and central sector power generation against private sector generation is currently beyond the scope of our research. Suffice it to say that government officials and

¹²⁸ The three historical phases in the government's approach to awarding contracts can also be observed in the other Indian states that have pursued an IPP policy, including Gujarat, Maharashtra and Tamil Nadu. In each case, there is overlap between the phases. For example, SEBs and state regulators have informed us that for some projects already under development (i.e. involving ongoing discussions between sponsors and the government) the second generation approach may still be taken. Tariff-bidding, however, is currently the dominant approach to the current generation of projects being developed.

¹²⁹ For an overview of BSES/Reliance Andhra Power, the only IPP in Andhra Pradesh not investigated during field research, see the following APERC Order conditionally approving the modified BSES/Reliance PPA, available at <http://ercap.org/orders/BSES%20ORDER%20Final.htm>.

¹³⁰ The state of Gujarat also features power plants structured as cooperatives with the SEBs participation.

management at APTransco argue publicly and persuasively that costs are unjustifiably high for IPPs and government generation has become more economically competitive. Industry, on the other hand, contests this view, stating that concessionary finance, hidden costs and subsidies, shorter plant life and diminished reliability add up to account for the unfavorable cost comparison.

The AP government and offtaker experience with individual IPPs has varied somewhat, but the three most politically visible IPPs in the state (Lanco Kondapalli, GVK, and Spectrum), while each operational and earning returns, have been subject to large and small scale disputes. The serious problems that arose with the Spectrum IPP are reviewed in Box 2 below. GVK faced two renegotiations, and while the second renegotiation process was time consuming and difficult for the project sponsors (coming in the wake of the Dabhol scandal), government officials contend that it involved concessions on the part of both parties, with the most important points operating in favor of GVK.¹³¹ (The overall success of the GVK project for investors has been a difficult issue to resolve clearly; opinions from industry participants familiar with the project vary widely).

APTransco has also pursued several smaller disputes with Lanco Kondapalli, which was not renegotiated. According to interviews and figures provided by the state offtaker, Lanco's first bid contemplated a Rs. 1240 crore project cost. The tariff bid, based on levelized tariff cost, worked out to 1.40 rupees per unit for the fixed cost component of the tariff. When project costs came before the CEA for approval, total approved project cost was Rs. 1027 crore, lower than the project cost reflected in the tariff bid. This discrepancy led to a levelized tariff of Rs. 3.49 per unit under the PPA, and Rs. 2.89 per unit taking into account the lower CEA approved costs. APTransco filed a notice stating that it would only pay based on the tariff resulting from CEA's approval. Lanco argued against this position, stating that because Lanco Kondapalli is a tariff bid project, the bid tariff in the PPA should govern. Lanco successfully sought a stay in court against APTransco's notice and APTransco is currently paying the higher tariff rate while the matter is litigated.

The Lanco PPA also contemplates installed capacity of 368 MW, which must be rated and certified based on calculations that take into account site conditions, such as ambient air temperature. According to interviews with AP Transco, actual installed capacity is 351 MW, but AP Transco pays based on a rating of 368 MW. This dispute was referred to the regulator and is now in court. Lanco obtained a stay against the regulator in this case as well. Arbitration is viewed as a last resort. These disputes suggest that while Andhra Pradesh is often viewed as a relatively investor-friendly state for IPPs, the government and IPPs have had their share of

¹³¹ Interview with Rachel Chatterjee, Chair and CEO of AP Transco, June 3, 2005. Chatterjee points to several specific renegotiated provisions that favored GVK, including: (i) provisions providing for a central government counter-guarantee; (ii) a fuel choice clause allowing naphtha as an alternate fuel; (iii) an escrow mechanism required to open prior to COD to cover the construction period; and (iv) a richer plant load factor ("PLF") incentive formula, which remains at a low 68.5% PLF and which was changed from a percentage of the return on equity to a percentage of overall equity committed to the project. The key terms that changed in the government's and/or lenders' favor, according to Chatterjee, were: (i) a revised ceiling on capital cost; and (ii) a clause providing for debt conversion to equity in the event of default. In addition, the term of the GVK contract was reduced to 18 years, as the normal useful life of a gas-fired plant is less than 30 years.

smaller disputes, which reflect state official's ambivalent position toward much needed, but more expensive privately produced power.

From the perspective of investors, the Andhra Pradesh government seems to have performed relatively well, although unsurprisingly, investors, like the government, find it in their interest to give the impression that they are being squeezed. AP Transco has a strong record of paying its bills to IPPs, bolstered largely by a fully operational escrow arrangement through which all APTransco revenue passes, and promoted in part by a significant discount from both the fixed and variable tariff components for prompt payment (at least three days in advance of payment due date). Official renegotiations of contracts has occurred during the pre-operational period in a project life cycle – once a project achieves commercial operations there have been no renegotiations of the fundamental project terms to date. The PPAs for both GVK and Spectrum were renegotiated prior to financial close, and the tariff bid projects faced interesting government pressure to lower their tariff after the bid had been accepted but before financial close.

There are, however, two brewing conflicts that may change this. First, the APERC has requested that the MOU projects pass on to consumers the gains achievable from refinancing given the sharp decrease in interest rates since the mid-1990s, when the MOU projects reached financial close. GVK, Spectrum and Lanco Kondapalli have challenged this move in court, where the matter is pending. Second, the AP government has convened a political committee to review three of the IPPs – GVK, Spectrum, and Lanco Kondapalli – to deliver on a campaign promise by the recently elected Congress Party government. While renegotiation discussions were being held between the generation companies and the government committee regarding reduction of fixed costs for the projects, AP Transco vocally continued to demand lower fixed costs, raising the political acrimony of the dispute.

Thus in Andhra Pradesh, the road has been treacherous, but with outcomes that are not entirely negative. Most IPPs were forced to change the terms of their original bargain under pressure from the SEB. GVK was renegotiated twice before reaching commercial operations. These renegotiations addressed some issues of mutual concern, such as awkward provisions in the original contract, but also lowered the performance incentives that the plant was eligible to earn. However, since commercial operations in 1996, the PPA has been performed as expected, with timely payments from AP Transco.

The fuel allocation problems first faced by GVK are amplified in the case of competitively bid projects that signed PPAs with AP Transco (then APSEB) in 1997 and became caught in the crosshairs of gas politics in India. As with many IPPs in India, including GVK, these projects were designed to run on naphtha, with an anticipated shift to natural gas when expected gas fields came online. When naphtha prices were deregulated in 1998 by the Indian government and rose sharply, the pass-through treatment for fuel prices in the Indian IPPs translated into a steep escalation of the cost of power from naphtha burning plants. This episode arguably produced more stress on Andhra Pradesh's IPPs than any other, and was used by the SEB as leverage to pressure IPPs to renegotiate.

Underpinning this experience in Andhra Pradesh is the fact that, through the entire period during which IPPs have been operational, the state has continued to experience an acute energy shortage.¹³⁴ Thus, the electricity generated by the IPPs, while

BOX 2. SPECTRUM POWER

The most prominent controversy among IPPs that reached COD in Andhra Pradesh concerns Spectrum Power. While the case provides a paradigmatic example of mismanagement and (according to numerous sources) fraud on the part of the project manager,¹³² it provides less conclusive evidence of systemic problems with the IPP approach, owing to the difficulty of separating out the impact of personalities and management missteps from project fundamentals. However, based on the factors discussed below, the Spectrum experience offers a few common sense lessons.

Originally developed as a “fast-track” project by a team composed of a US-based Indian national with GE ties and his Hyderabad-based brother-in-law, the project soon deteriorated into a protracted dispute between the two sponsors. Spectrum became possible when Andhra Pradesh officials reallocated half of the gas allocation slated for GVK to the Spectrum promoters, a change that was naturally opposed by GVK management.

The Spectrum project had two fundamental weaknesses. First, the local partner in the project reportedly contributed to gross financial mismanagement of the project, including enormous cost overruns. Second, poor project structuring allowed poor management to continue unchecked. For example, there was no trust and retention agreement or account in place to control the use of project revenues (the popular “cash-cade”), which greatly undermined the lenders’ ability to control project cash flows. Eventually investigations of fraud by Indian authorities and failure to make loan repayments led domestic lenders to declare default and reconstitute the board of the project company. A Supreme Court order also directed the project company to sign a trust and retention agreement in 2002 to enable lenders to have direct control of Spectrum’s cash flows.¹³³

For the purposes of the IPP study, the Spectrum story provides a clear illustration of how poor local partner selection and structuring deficiencies can increase vulnerability to financial mismanagement, fraud and inability to repay project debt.

¹³² Abheek Barman, A Power Project that Floats on Air, THE ECONOMIC TIMES, September 4, 2002; THE ECONOMIC TIMES, *Stop the Rot*, October 25, 2001.

¹³³ Financial Express, *Spectrum Signs TRA Pact with Lenders*, September 19, 2002; Financial Express, *IDBI Files Fresh Application in SC on SPGL Mortgage Transaction*, May 5, 2003.

expensive, is very much needed. This is in contrast to several other countries, such as the Philippines, Thailand, Malaysia, and Indonesia, where overbuilding led to overcapacity problems and difficult payment burdens to the IPPs.

3. *State of Gujarat*

(a) Electricity Sector and State Electricity Board

Gujarat is one of the most developed and industrialized states in India, a factor that is reflected in the profile of its electricity industry. In 2000, per capita consumption of electricity was 835 kilowatt hours, as compared to an average of 355 kilowatt hours for India overall. Overall, consumption has quadrupled between 1980 and 2000, from 8 trillion kWh to 33 trillion kWh. However, consumption is still heavily agricultural, with 40% of demand coming from the agricultural sector. Installed capacity was almost nine gigawatts in 2002, of which 27% was provided by private generators.¹³⁵

In terms of performance, the GEB seems typical for a state electricity board in India. Through the mid-1990s, revenues amounted to only one-fourth of annual revenues—with the balance coming largely from government subsidies. Tariffs remained highly subsidized, particularly for agricultural consumers, although in line with most of India.¹³⁶ As a state, Gujarat placed seventh in a pool of 26 SEBs ranked by the debt rating firm CRISIL in 2003 for state power sector performance.¹³⁷

Gujarat has not been a leader in reform efforts. The major activity in the development of the IPP sector came in the mid-1990s (a fact that may have helped Gujarat avoid some of the mistakes of other states that had pioneered reform). Subsequently, in 1998, following the enactment of the national Electricity Regulatory Commissions Act in 1998, Gujarat established an independent regulator (GERC) to oversee the electricity markets and reform tariffs. Efforts continue in this arena, with the passage of a state reform statute in 2003 and unbundling of the state utility in 2005.

(b) Gujarat IPP Overview

Gujarat began its IPP program notably later than other states, particularly trailblazer Andhra Pradesh. None of the Gujarat IPPs is a “fast-track” project like Dabhol, GVK, Spectrum, or ST-CMS Neyveli. Available data indicates that fixed costs on a per megawatt basis were clearly lower than in Andhra Pradesh, Tamil Nadu, and Maharashtra and among the most competitive in the country. Additionally, politics appear to play a somewhat lesser role in the

¹³⁴ POWER ASIA, *Blackouts hammer India's economic output*, January 8, 1996; THE HINDU BUSINESS LINE, *Power cut may continue for a few more days in AP*, July 2, 2004.

¹³⁵ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Gujarat, India*, PESD Working Paper #21 (2004).

¹³⁶ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998).

¹³⁷ CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

Gujarat electricity sector compared to the other states that PESD has examined closely, i.e. Andhra Pradesh, Tamil Nadu, and Maharashtra. This observation was made by all of the main players in the Gujarat electricity sector – the GERC, the GSEB and the project companies themselves. Contrary to the strategy adopted by project companies in Andhra Pradesh, one IPP project manager stated that the best approach is to involve politics and the press as little as possible. Based on our interviews, the changes made to PPAs in Gujarat did not ultimately stem from political pressure or an election agenda. Moreover, the most common reported tools for resolving disputes with the GEB involved restructuring fixed-cost or pass-through elements. The main components of renegotiations and tariff reduction in Gujarat were refinancing project debt and altering fuel supply arrangements from naphtha to natural gas to reduce variable costs. However, such changes to pass-through items involved little actual cost to the bottom line of IPPs, and ultimately made them more competitive (and thus more profitable) in the merit dispatch order system.

Another key feature of the Gujarat electricity landscape is the state’s two LNG terminals and recently expanded gas fields. The availability of new gas supply was critical to overcoming the crisis that ensued for IPPs in Gujarat when naphtha prices skyrocketed in 1999-2000. Gujarat IPPs led the way in signing private gas contracts, as opposed to relying on the soft commitments from GAIL on gas allocations that have caused serious problems for plants in other states. For example, Essar Power and Paguthan both enjoy private gas contracts with two-way take-or-pay provisions that provide the project companies with assurance that they will receive their committed gas supply or the resulting price difference if delivery is not made. Reports from IPPs and the state offtaker in Gujarat in field research interviews were the most positive among the four states selected for focus in the India study.

4. *State of Tamil Nadu*

(a) Electricity Sector and State Electricity Board

In contrast to both Gujarat and Andhra Pradesh, Tamil Nadu was a late reformer, establishing the Tamil Nadu ERC in 2002 and still providing free electricity to farmers. Estimates of the annual losses to the Tamil Nadu Electricity Board (TNEB) reach US\$625 million,¹³⁸ but energy accounting studies have only begun recently and expect to focus greater attention on the problem of the TNEB’s financial unsustainability.¹³⁹ At the same time, these numbers are relative in the Indian power sector – according to a 1998 report by the Infrastructure Development Finance Corporation, TNEB was one of the most effective SEBs in terms of both financial and technical factors.¹⁴⁰ Through the mid-1990s, revenues amounted to only one-fourth of annual revenues—with the balance coming largely from government subsidies. Tariffs remained highly subsidized, particularly for agricultural consumers (who as of 2003 were not levied any tariff at all).¹⁴¹ While the TNEB’s operations and to a lesser extent its financial condition may have been superior to most electricity boards during the development of IPPs in the state, Andhra Pradesh had relatively less government support compared to Maharashtra,

¹³⁸ Suresh Seshadri, *Covanta’s second Indian utility starts generation*, Reuters, October 1, 2001.

¹³⁹ CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

¹⁴⁰ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998).

¹⁴¹ *Id.*

Andhra Pradesh and Gujarat. This compounded the cash flow crunch, as the state government was not disbursing the full level of subsidies requested in the TNEB's claims. With the TNEB's losses mounting, CRISIL recommended in 2003 that the state government increase its financial support to prevent cash flow pressure from impacting the operating efficiency of the TNEB. Although the TNEB in the past was able to service its debt through sound but constrained cash flow management, gearing levels rose considerably for the TNEB in the years leading up to 2003, and debt coverage ratios deteriorated as tariff rates and subsidy levels failed to keep pace with mounting power purchase costs, attributable in part to IPPs that came online in the state.¹⁴² Failure to fully fund the TNEB's losses has also led to endemic problems for IPPs in the state.

The Tamil Nadu power sector ranked ninth in a pool of 26 SEBs evaluated by CRISIL in 2003 for overall performance, placing it behind the other three states examined in detail as part of this study (Andhra Pradesh first, Maharashtra ranked fifth, and Gujarat seventh).¹⁴³

(b) Tamil Nadu IPP Overview

Tamil Nadu emerged as a stark counterexample to the relative successes of Gujarat and Andhra Pradesh with TNEB only paying just enough money to ensure that the project companies can service their debt. There are five Tamil Nadu IPPs, all of which came online between 1998 and 2001. With five pure IPPs (as opposed to cooperative structures) on the grid, Tamil Nadu has more operational IPPs than any other state in India. If cooperatives such as the GIPCL plants in Gujarat and the Andhra Pradesh Gas Power facility are counted, Tamil Nadu is still at the head of the pack alongside Gujarat and Andhra Pradesh, each with five plants classified as IPPs. Three of the four IPPs running on heavy fuel oil in India were developed in Tamil Nadu (the other being Tata's 81 MW Belgaum facility in Karnataka). Like Andhra Pradesh, all of the IPPs in Tamil Nadu are relatively small in size, with the largest, the natural gas and naphtha fired PPN plant, producing only 330 MW of electricity.

Like Andhra Pradesh, Tamil Nadu began with very aggressive plans to build out private generation capacity. While many projects were discussed and developed in early stages, few developers actually broke ground, although the state still emerged with a relatively high number of low capacity IPPs (five in total). Yet had Tamil Nadu achieved its original objective for capacity expansion, the current distressed situation of the electricity sector there would be in even worse shape. In 1999, the advisory branch of Indian rating agency Crisil estimated that if Tamil Nadu were to follow through on the 2,564MW of private projects that were in development, the subsidy to keep the state electricity board solvent would need to double.¹⁴⁴

In Tamil Nadu, IPPs have been locked in a protracted dispute that stems from a 2001 policy of paying only 2.25 rupees/kWh to each plant, regardless of contracts or costs. Facing extreme financial distress, both the Tamil Nadu Ministry of Finance¹⁴⁵ and the Tamil Nadu

¹⁴² CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

¹⁴³ *Id.*

¹⁴⁴ *Subsidy support to TNEB required to be doubled*, Business Line (The Hindu), October 25, 1999.

¹⁴⁵ See White Paper on Tamil Nadu Government's Finances, available at <http://www.tn.gov.in/>.

Electricity Regulatory Commission¹⁴⁶ have directed the TNEB to reduce power purchase costs from the IPPs. The 2.25 rupee policy was apparently derived by quantifying the TNEB’s average cost recovery for the sale of power.¹⁴⁷

This policy was announced as a temporary measure to restore some financial viability to the TNEB – and was accompanied by a significant increase in tariffs. During the dispute, the TNEB has continued to track its arrears to the projects (based on the difference between contract payments and actual payments) – which at one point reached \$150 million. Nonetheless, the dispute continues. Compounding all of this is the low dispatch from many of the plants, illustrated in the adjacent table.

PPN	40%
GMR Basin Bridge	73%
Samalpatti	73%
Madurai	70%
ST-CMS Neyveli	93%

From this common starting point, the dispute for each plant diverges somewhat depending on project characteristics. Each IPP in Tamil Nadu has reacted differently, reflecting the relative influence of a range of project characteristics, including fuel choice, local partner selection and relationship, and sponsor strategy and expectations. Notwithstanding the dismal experience for investors in Tamil Nadu, the state’s experience does illustrate how power purchase agreements do provide some measure of protection against the obsolescing bargain and guides the parameters of discussions when disputes emerge or crises erupt. The TNEB has maintained records of outstanding payments to the IPPs and has stated its intention of covering these payments when it has the financial wherewithal to do so. These promises may, of course, prove to be illusory. However, the original PPAs continue to frame the relationship between investor and government.

The adjustments required to put IPPs back on track in Tamil Nadu demand cooperation and coordination among an array of actors, each with slightly diverging interests. As the drama unfolds between the IPPs and local authorities in Tamil Nadu, new evidence may emerge that shows how different investor strategies in a crisis situation result in different project outcomes; the PESD research team will continue to observe the Tamil Nadu situation for additional lessons in this area.

V. CONCLUSION

India succeeded in attracting a great deal of foreign interest in its IPPs throughout the 1990s. When compared against other countries with IPP programs, India was among the leaders in terms of total development activity and number of projects reaching commercial operations. Between 1991 and 2003, 22 projects of more than 50 MW were commissioned alongside nine

¹⁴⁶ Directing the TNEB to “pursue all possible options” to reduce costs from IPPs, the TNERC summed up the government’s position as follows: “[T]here has been a qualitative change in the environment for participation of private sector in the power projects and the Board must make efforts in consultation with and co-operation of the IPPs to review the existing arrangements with a view to bring down the cost of power purchase.” See <http://tnerc.tn.nic.in/orders/MP%20263%20Nellikuppam%20krishnamurthy.pdf>.

¹⁴⁷ *IPPs fault TNEB for poor tariff*, The Hindu (Business Line), August 28, 2001.

¹⁴⁸ N. Ramakrishnan, *TN private power producers find going tough*, The Hindu (Business Line), April 18, 2005.

small independent generators bringing the total capacity addition to nearly 6000 MW.¹⁴⁹ However, there are three important qualifications to this apparent progress in private sector participation. First, while the new IPP capacity is significant, the state share of electricity generation continues to dwarf the private sector's share. India failed by a long shot to achieve the aggressive capacity expansion objectives laid out in the central government's original IPP policy. Although thousands of MOUs were signed with foreign and domestic project developers, only a miniscule fraction eventually broke ground for construction and reached commercial operations. Frustration with the high mortality of projects in India still runs deep in the minds of investors, particularly foreign project developers who had to invest even greater time and effort in navigating the Indian bureaucracy.

Second, and apart from high project mortality in the development stage, the controversy surrounding the Dabhol project and the Tamil Nadu IPPs has raised strong cautionary signals to potential investors. The fears engendered by these high profile disputes and magnified by the Indian and international media resulted in the reversal, by and large, of early foreign enthusiasm about investment prospects in the Indian electricity sector. Although interest has started to ripen again as domestic players and foreign late comers such as CLP press on with project expansions, even these relatively successful project sponsors remain hesitant to sell to cash strapped SEBs, instead opting whenever possible to enter into multiple contracts with new buyers such as the central Power Trading Corporation and industrial offtakers.

Third, India continues to face substantial shortfalls in electricity supply throughout most of the country. As in other countries, supply shortfalls and actual demand for private power has collided with the financial political inability of state utilities to pay for unmet electricity needs. This reality is only compounded by the pressures of populist politics, which make tariffs at actual cost all the more difficult. When these twin challenges were made concrete by several prominent beleaguered IPPs, foreign investment over the last five years flowed out of the electricity sector rather than in. Most foreign investors, including major players such as Electricite de France, PowerGen, and Mirant, have withdrawn from India, at least for the time being. Many continue to watch and wait, particularly with the implementation of new reform legislation, particularly the recent 2003 Electricity Act. Yet thus far, the pace and implementation of reform has not proved successful in raising tariffs to cover costs, and although some states have made progress, work must still be done to improve abysmal bill collection rates. The renegotiation and cancellation of PPAs in India reflected these failures of reform by forcing heavily burdened SEBs and regulators to squeeze private investors when facing a budgetary impasse, which was aggravated by political transitions.¹⁵⁰ For example, Mirant specifically cited the failure of government-led electricity sector reform in India when explaining its decision to not enter the market. The 2003 Electricity Act, discussed below, can be viewed partly as a response to the exit of foreign investors. However, with the retreat of global energy investors and contractors, well established domestic electricity and infrastructure companies such as Tata and Reliance have partially filled the gap and may continue to hold the competitive advantage.¹⁵¹

¹⁴⁹ Ministry of Power; cf. *A bits and pieces approach*, Asian Power, August 20, 2001.

¹⁵⁰ Clive Harris, *Private Participation in Infrastructure in Developing Countries: Trends, Impacts and Policy Lessons* (April 2003)

¹⁵¹ *Id.*

TABLE 6: FIXED COST PER MW FOR OPERATIONAL IPPS (RS. CRORE)

Project Name	Fuel Choice	MW	Fast Track	Fixed Costs/MW
GIPCL Baroda Unit I*	Natural Gas / Naphtha	145	No	2.539
Lanco Kondapalli Power	Natural Gas / Naphtha	350	No	2.958
Essar Power	Natural Gas / Naphtha	515	No	3.236
Jamshedpur Power	Coal	308	No	3.334
PPN Power	Natural Gas / Naphtha	331	No	3.394
Gujarat Paguthan Energy	Natural Gas / Naphtha	655	No	3.509
Balaji Power (Madurai)	Distillate Gas	106	No	3.625
Spectrum Power Generation	Natural Gas / Naphtha	206	Yes	3.633
Samalpatti Power	Distillate Gas	106	No	3.697
GVK Power	Natural Gas / Naphtha	216	Yes	3.778
GMR Power (Basin Bridge)	Distillate Gas	200	No	3.784
Malana Power	Hydro	86	No	3.976
Jindal Tractebel Power	Coal	260	No	4.207
Dabhol Power	Natural Gas / Naphtha	2015	Yes	4.492
GIPCL Surat Unit*	Coal	250	No	4.669
ST-CMS (Neyveli)	Coal	230	Yes	5.217

Source: Government of India, Ministry of Power, Private Power Projects at a Glance¹⁵²

The Indian case studies demonstrate that even with high-level central government support, both from the host country government and the investor's government, a project may flounder badly. Moreover, the Indian experience suggests that while foreign investors should seek support from their home country, multilateral agreements and arrangements may be less politically charged (cf. the Dabhol project, in which the World Bank very visibly declined to participate). Yet multilateral participation has its drawbacks in the view of some domestic project developers, making it difficult for local sponsors and financiers to adapt flexibly to changing circumstances and requiring overly rigid project and financing documentation. Partnering with local companies from the outset may provide some insulation against challenges lodged by opposition groups and NGOs (e.g., the presence and positive reputation of GVK and Lanco in Andhra Pradesh prior to project development). Credibility can also be enhanced by inviting a broad range of stakeholders to the bargaining table, even if it initially delays closing the deal. Most importantly, instead of negotiating a maximum return in the short term, project sponsors should consider the importance of obtaining a balanced agreement and fair return that lays the foundation for future opportunities, paying careful attention to the probable financial constraints on SEBs and state governments and not placing full faith behind central government guarantees, which have become equally subject to politicization. As illustrated by individual cases from this country study and others, the more an investor succeeds in shifting all risks under the power purchase agreement onto the offtaker to create a contract that leans heavily in their favor, the greater that investor's overall exposure to renegotiations.

¹⁵² Available at http://tempweb30.nic.in/projects/pvt_power_projects.htm; the four projects lacking publicly available fixed cost data did not require techno-economic clearance from the Central Electricity Authority. As a result, fixed cost data is not available through the Ministry of Power or CEA.

Several other prominent themes emerge from the India study. First, there is the tendency to confuse latent demand with actual capacity to pay, and to rely on fantastic and somewhat arbitrary growth projections that never bear out. Among the four states examined in the India study, this was the case in Maharashtra. During the development of Dabhol, electricity demand was projected to grow at 18% annually; in reality growth averaged 5.1%. Second, multilateral actors presupposed and relied upon the eventual success of key electricity sector reforms in India, most importantly the ability of SEBs to set retail tariffs at the level required to recover costs. The presumption that such reforms would keep pace with the development of India's IPP program proved to be unwarranted. Prices remained low and the SEB's capacity to pay for market priced capacity additions (sometimes with large risk premiums attached) lagged far behind the build out of IPPs. Had the proposed volume of projects gone forward, it is difficult to imagine how the SEBs and governments would have responded; undoubtedly the IPP program would have faced an even more pronounced and widespread crisis. Given the modest impact of IPPs on the electricity sector, however, the situation never became truly severe. While India has more than its share of electricity sector problems, analysis of IPP performance has inevitably become more cynical than justified by the actual experience on the ground. The vast majority of analysis on Indian IPPs concentrates on a few massive failures, such as India's Dabhol or the Cogentrix mega-project that never got off the ground. From these few prominent case studies of pathological projects and dysfunctional state utilities, observers have put forward a range of anecdotal and tailored hypotheses for why particular projects fail. Yet while some states in India exhibit more or less muted versions of the obsolescing bargain, others have struggled to create a mutually sustainable investment environment for the government and investors alike, and some investors have clearly maintained an interest in continued expansion in the more hospitable state power sectors.

As with many developing (and developed) markets, the electricity sector in India remained in flux through the 1990s and continues to evolve rapidly to this day. Since the beginning of India's IPP program, project companies have had to compete in a conflicted context of partial and evolving reform. Hybrid state electricity sectors combined elements of market competition with continued state dominance and intervention. In such an environment, instability is common; firms that operate most effectively are those best able to navigate highly politicized markets, providing an inherent advantage to domestic actors. The Electricity Act of 2003 has been designed to transform the industry from a single-buyer market to a multi-buyer, multi-seller system—and in the process to remove the weak link of the state electricity boards that has undermined reform efforts to date. At the same time, domestic players have grown increasingly dominant and mobilized capital for substantial investment in the electricity sector. These firms including state-controlled NTPC, national firms led by Reliance Energy and Tata Power, and niche regional players such as the GVK, Essar, and Lanco groups. Following the 2003 Electricity Act, competition will center around firms willing and able to undertake the arduous task of selling power supply contracts to a dispersed market of more solvent offtakers, not the structurally simple but high risk single buyer market of the past. By placing a premium on local knowledge, as well as existing commercial and political presence, this development could potentially limit foreign investment dramatically.

In conclusion, despite a flurry of activity and controversy over the last fifteen years, IPP obligations in India have remained small relative to the overall electricity sector and government

budget as a whole. Even in the cases where the cost of state IPP programs was relatively manageable politically and financially, it must be remembered that the size of the IPPs in the sector is small relative to total generation. However, the lessons of the past have led to marked improvements. In order for the next round of investment to succeed, fixed costs must be kept to competitive levels (see Table 6 below), and reform of retail tariffs must progress more rapidly.

Without comprehensive reforms, the private sector will increasingly choose to deal only with itself, taking advantage of the increased ability to sell to private offtakers but leaving the most power hungry regions and needy customers, such as farmers, without the capacity additions they too require. As policymakers, technocrats and investors continue to experiment with IPPs in India, it is hoped that the private sector will take the steps required to become increasingly competitive on cost, and state utilities and governments will proceed with the difficult reforms necessary to carry out their service obligations to Indian consumers on a sustainable basis.

GVK Industries, Jegurupadu Power Project

Andhra Pradesh

Specifications			
Capacity	216MW	MOU	1992
Fuel	Naphtha / Natural Gas	PPA	1993, 1994, 1996
Technology	Combined Cycle	Financing	1997
Approved Cost	Rs. 8.16 billion	COD	1996, [2000]
US dollars (1993)	US\$261 million	PPA Term	18 years
Leverage	70/30	Ownership	BOT
Sponsors	GVK Group (40%), CMS Energy (24%)		
EPC Contractor	ABB		
Operator	CMS (original), GVK (current)		
Multilateral involvement	ADB, IFC		
Offtaker	AP Transco (formerly APSEB)		
Lenders	IFC, Nordic Investment Bank, IDBI		

I. OVERVIEW.

The 216 MW GVK Jegurupadu natural gas fired power plant was developed as one of the original “fast-track” projects in India. The project sells its entire output to the Andhra Pradesh Transmission Corporation (AP Transco), the state owned utility and offtaker in Andhra Pradesh (“AP”) that derived from the unbundling of the AP State Electricity Board. Andhra Pradesh was an early and relatively effective reformer of its electricity sector in comparison to other Indian states and the state offtaker has maintained a reliable payment history to all of its IPPs. Nonetheless, political controversy, government reviews and renegotiations have become recurring episodes in the IPP market in AP. GVK, however, has weathered this uncertain climate reasonably well and is a relative success in the universe of IPP cases – particularly among Indian cases.

II. PROJECT STRUCTURE

A. Stakeholders.

The principal sponsors for the GVK project were GVK Group of India (the local partner), CMS Energy of the United States (original O/M contractor), and ABB Equity Ventures (the EPC contractor for the project). GVK is an Indian corporation with substantial experience in infrastructure projects, but none (prior to GVK) in power plants. Since COD in 1996, both ABB and CMS

Project Equity	
GVK Group	40%
Asia Infrastructure Fund	25%
CMS Generation	24%
IFC	10%
AP Transco	2%
ABB	5%

have exited the project. GVK now holds the O/M contract. The project included significant support from multilateral institutions. The IFC was a lender and equity holder. The Asia Infrastructure Fund was also a 25% shareholder. Finally, AP Transco

held a small stake in the project, although by most accounts the state utility played a passive role in the project.

The GVK project was constructed largely on balance sheet by the sponsors – only after COD did the sponsors close on commercial lending for the plant. Financing for the project came primarily from the IFC and from a syndicate of Indian commercial banks, with IDBI as the lead arranger. During the initial financing arrangements for the project, the sponsors anticipated offering equity in the project through the domestic Indian capital markets. ABB Project and Trade Finance acted as financial adviser to the project and worked closely with the IFC during the financing negotiations.

Debt Structure	
IFC	US\$30M; DM65M
Nordic Investment Bank	DM16 million
IDBI (arranger)	\$19.2M
Total	US\$181M

B. Fuel Arrangements.

The project was designed to burn both natural gas, supplied under contract by the Gas Authority of India (“GAIL”) and naphtha, supplied by Bharat Petroleum Corporation Limited (“BPCL”). Natural gas is available from the onshore Mandapeta/Tadipaka gas fields of the Krishna-Godavari basin, located on the AP coast less than 30 kilometers from the project site (Source: Tinsley, 2002). Fuel is supplied under a 13 year contract with GAIL for 0.75 mcmd of gas, which provides enough fuel to operate two of GVK’s gas turbines fully on gas and the third with up to 20% gas.

GAIL has also allocated 0.30 mcpd of gas on a temporary fall-back basis, which has allowed the plant to operate with 100% natural gas through 2002 under the GAIL supply contract. There are provisions for the extension of the GAIL gas supply agreement on mutually agreeable terms (Source: Tinsley, 2002). As a dual-fuel plant, naphtha is available as a substitute fuel through BPCL if gas prices escalate. The cost of building the pipeline and metering facilities to move gas from the KG basin to the project site is borne by GAIL, but GAIL recovers this in part through a monthly fixed transportation cost (which escalates annually) for piping the gas. The price of gas was government controlled through 2002, determined by government guidelines.

The project was originally allocated gas for a 400MW plant. This allocation had been taken from a nearby NTPC project that had stalled. In the early 1990s, however, Indian authorities halved this allocation and gave 200 MW to sponsors for the Spectrum project in Andhra Pradesh. GVK subsequently altered plans and built a 216MW facility.

C. Power Sales Arrangements.

GVK sells its entire output to AP Transco under an 18-year PPA. The PPA was originally signed in 1993, and renegotiated on two occasions in 1994 and 1996. The first renegotiation was essentially a chance for the parties to correct poorly drafted provisions in the first PPA. The second renegotiation was far more painful. When GVK came up for review for a counter-guarantee (“CG”) from the Government of India (“GOI”), the

Dabhol controversy was beginning to boil over into full blown disaster, and GOI officials were extremely hesitant to issue another such guarantee without raking GVK over the coals. This renegotiation dragged on for almost two years until the new PPA was signed in 1996, and the CG only became effective in 1997. Until this point, the IFC had refused to disburse its loans to the project, and GVK was almost \$100 million in arrears to ABB – thus, the project was constructed largely on balance-sheet.

Under the revised PPA, GVK cannot sell power to third parties. If APTransco fails to take power from GVK due to low demand or for other reasons attributable to APTransco, it still must pay GVK the fixed charges that would be incurred at 68.5% PLF on the approved capital cost. At 68.5% PLF, the minimum take-or-pay tariff stream provides coverage of project debt and O&M obligations (Source: Tinsley, 2002).

Both fuel and foreign exchange risk are treated as pass-through costs in the PPA. FX tariff risk is passed through under the fixed cost component of the tariff. Specifically, the FX risk is taken on by APTransco up to the point of remittance of foreign exchange for debt service. Additionally, the PPA provides that the return on equity for the foreign exchange component of total project equity is referenced to current exchange levels, shifting further FX risk on to the government.

D. Facilities, Construction and Cost.

According to ABB, the turnkey EPC for the final 150 MW of the combined-cycle facility was valued at approximately US\$195 million. By the time ABB announced that it had finalized the EPC with GVK, the project company had already installed the first of the plant's three gas turbines and connected it to the local electricity grid. Full commercial operation of the 235 MW facility was scheduled for the summer of 1997 (Source: ABB press release, August 1996).

ABB was responsible for the overall planning and project management during construction and supplied three 50 MW gas turbo-set turbines to the project (rated at 46 MW each), together with associated heat recovery steam generators, one steam turbo-set turbine (rated at 77 MW) and the plant control system (Source: GVK homepage, 2004). ABB's local subsidiary, ABB India, had substantial resources and manufacturing capabilities in India and supplied a significant portion of the project infrastructure. With over 10,000 people employed in India and an order intake of US\$670 million in 1995, ABB India was positioned to play a leading role in the development of the project. APP India provided the cooling water plant, switchgear and transformers, as well as planning and management of civil works for the project. (Source: ABB press release, August 1996).

Sponsors absorbed all construction risk by proceeding with construction before securing external financing and the central government counter-guarantee. Under the EPC, ABB had to execute the turn-key construction contract within 28 months from the date of financial close (Source: Tinsley, 2002). With the LDs in place under the EPC, the EPC contractor bears the risk of construction delay as with any ordinary EPC contract.

However, because several lenders refused to disburse loans until the central government counter-guarantee was issued, and then ended up disbursing only after commercial operations, ABB faced significant payment delays and ended up financing much of the construction itself, before payments from the project company caught up.

The O&M contract limits the liability of the operator (JOMC) to the amount of base fees, which may or may not cover the cost of property or other consequential damages. GVK has purchased industrial all-risk insurance with business interruption coverage to mitigate this risk (Source: Tinsley, 2002).

E. Government Support and Guarantees.

1. *Central Government Counter Guarantee.*

As one of India's eight fast-track IPPs, GVK was eligible for a counter-guarantee of the project's foreign loans by the Government of India ("GoI"). However, like other projects unfortunate enough to follow Dabhol in the process of negotiating a counter-guarantee ("CG") with the central government, GVK faced pressure from Indian officials to dilute the terms of the CG from that originally envisioned in the fast-track program. The GoI issued the counter-guarantee in September 1996, which covers repayment for "external commercial borrowings" up to US\$77.7 million (Source: Tinsley, 2002). The project also obtained a guarantee from the AP government in March 1996 that backed all of AP Transco's payment obligations under the PPA (Source: Tinsley, 2002).

2. *Escrow Account.*

As with other projects in Andhra Pradesh, the documentation for GVK established an escrow mechanism whereby the revenues of the state offtaker pass through a third-party escrow account, where IPP payments are deducted, before passing to state accounts. This arrangement has engendered significant dissatisfaction within the host government, and AP Transco officials have expressed frustration with this arrangement, arguing that their hands are bound with respect to resolving ongoing disputes with the IPPs, including GVK. Project sponsors in Andhra Pradesh, however, credit the escrow arrangements as helping to ensure payment security, although as secondary to commercial viability.

III. HOST COUNTRY CONTEXT: ANDHRA PRADESH.

The Andhra Pradesh electricity sector, while representative of India generally in many respects, emerged as a leader in reform efforts during the 1990s. Relative to other SEBs, the state utility has maintained a positive, if not stellar, performance record. Andhra Pradesh has recently ranked number one in independent reviews of state power sector performance.¹⁵³ In 2000, installed capacity in Andhra Pradesh had reached almost eight gigawatts and per capita consumption was 391 kilowatt hours, compared to 355 kilowatt hours on average in India. Hydropower and coal fired plants account for the

¹⁵³ Government of India, Ministry of Power, *Rationale for Andhra Pradesh State Power Sector Scoring* (2003); CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

majority of the generating capacity in the state, although dependence on combined cycle natural gas-fired projects has grown tremendously, primarily via the installation of private generators.

In 1998, the Andhra Pradesh unbundled its SEB into a generation company, APGenco, and a transmission and distribution company, APTransco, which also acts as the offtaker from IPPs. APTransco was further divided into a transmission company and four distribution companies in 2000.¹⁵⁴ Genco controls roughly 70% of installed capacity, with the rest coming from IPPs, cooperative power projects and captive generators. Technically, performance is mixed—the generation sector in Andhra Pradesh has averaged the highest plant load factors in India, but the transmission and distribution sectors often fritter away any potential gains with high losses and poor billing performance. Tariffs remain highly cross-subsidized, with prices for industry among the highest in India, yet almost non-existent for agriculture (e.g. in 1997-98, agricultural users accounted for 48% of sales, yet only 4% of revenue).¹⁵⁵

Policymakers in Andhra Pradesh sought to place the state's electricity sector at the vanguard of reform in India. The state was an enthusiastic participant in the early development of IPPs—two of the original eight fast-track IPPs (GVK and Spectrum) are in AP, both of which achieved commercial operations. In 1998, the state passed an electricity reform law that unbundled the state electricity board into generation and transmission units, and established an independent regulator.¹⁵⁶

IV. PROJECT PERFORMANCE.

A. For Investors.

According to analysts and GVK Industries, the plant has consistently operated at a plant load factor of 96% and above (Source: Tongia, 2003; GVK homepage, 2004). Following a detailed audit, the Tata Energy Research Institute (“TERI”) gave the Jegurupadu plant its highest rating for environmental performance in February 2003 (TERI project report, 2003). According to TERI, average stack emissions for NO_x and SO₂ were roughly 20 ppm and below detectable limits, respectively. Emissions are well below the standards set by India's Ministry of Environment and Forests. Wastewater is treated on site before discharge. Resultant sludge is used as manure within the power plant complex and treated water is used to irrigate the 160 acre greenbelt surrounding the complex.

Some sources familiar with the project suggest that returns have been healthy, but in fact lower than the expected 16%. Original equity sponsor CMS Energy exited the

¹⁵⁴ Id.

¹⁵⁵ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998)

¹⁵⁶ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Andhra Pradesh, India*, PESD Working Paper #20 (2004).

project beginning in 2001. In theory guaranteed a 16% rate of return, as one of the “fast track” projects under the 1991 amendments to the Electricity Act, the GVK project has seen returns whittled away by numerous smaller disputes. For example, due to depreciation of the Indian rupee against the U.S. dollar, the capital cost of the project increased by Rs. 1 billion over the amount sanctioned by the PPA. AP Transco was responsible for approval of the increased capital cost (Prayas report, 2000), but project stakeholders suggest that this has not occurred and the project is being paid on the original contract cost only. The project has had to earmark revenue that would go to equity returns in order to meet the increased debt service as a result. Additionally, the contract limits the pass-through of operating costs to 2% of capital costs, leaving a narrow margin.

As with all projects in the IPP study, it is difficult to determine with precision how profitable GVK has been. While some accounts (discussed in the prior paragraph) suggest a difficult operating environment, it is important to keep in mind that the PLF incentive threshold has remained at 68.5%, while availability has been far higher. Between incentives and the cost-based direct negotiation of the deal, the contract likely provides substantial opportunities to earn profits. Thus, despite ongoing controversy, the IPP study considers the GVK project to provide a positive investment outcome. Perhaps reflecting this, the GVK Group is moving forward with plans to expand capacity of the GVK facility by 220 MW to 435 MW total (“GVK II”). In 2002, the APERC released its load forecast order, which concluded that generation capacity requirements had decreased in the state (Source: Prayas report, 2002). Upon its initial submission to the Central Electricity Authority, the Techno-Economic Clearance proposal for GVK II was returned to the project developers (Source: Prayas report, 2002). By mid-2003, however, the GVK II expansion had received the necessary approvals, including consent from APERC in April 2003. The reported cost of the expansion is Rs. 7600 million (Source: GVK homepage, 2004).

B. For the Host Government.

From the host government perspective, project outcomes from GVK are also mixed. On the positive side of the equation, GVK pioneered private power development in Andhra Pradesh, likely opening the door for subsequent development. As noted above, the project has a strong environmental record, and as with other IPPs, has removed the costs of project development from government responsibility.

Nevertheless, state officials express dissatisfaction with GVK on several counts. Fundamentally, these objections revolve around the costliness of the plant—records kept by the Ministry of Power indicate a fixed cost of Rs. 3.778 crore / MW for GVK, which is approaching the high end of the spectrum even within IPPs in India. Project sponsors response to this is that several factors contributing to cost in GVK are beyond their control—such as high costs for EPC services in the global market at the time of project development, and high interest rates. There have been at least some discussions on refinancing the project and passing through cost savings to consumers (as some other Indian IPPs have done), but both sides argue that the other is holding up an agreement on this count.

A prominent aspect of GVK's history involves the repeated renegotiations of the PPA prior to reaching commercial operations. Renegotiation is often seen as one sign of trouble for an IPP, however, according to AP Transco officials these renegotiations largely favored GVK. Specific elements of the renegotiations they point to include: (i) the eventual provision of a GoI counter-guarantee; (ii) the fuel choice clause that allowing naphtha as an alternate fuel; (iii) establishing an escrow mechanism and requiring that it to open prior to COD to cover construction period; and (iv) a richer plant load factor ("PLF") incentive formula, which remains at a low 68.5% PLF and was changed from a percentage of the return on equity to a percentage of overall equity committed to the project. The key terms that changed in the government's and/or lenders' favor were: (i) a revised ceiling on capital cost; and (ii) a clause providing for debt conversion to equity in the event of default. In addition, the GVK term was reduced to 18 years, to reflect the fact that the normal useful life of a gas-fired plant is less than 30 years.

As in the case of Kondapalli, these disputes continue to simmer. AP Transco officials argue that their hands are tied because of the escrow arrangements, while company officials maintain that their profits have already been squeezed substantially.

Lanco Power, Lanco Kondapalli Power Project

Andhra Pradesh

Specifications			
Capacity	368.144 MW	Bidding	1995-96
Fuel	Naphtha / Natural Gas	PPA	March 1997
Technology	Combined Cycle	Financing	December 1998
Approved Cost	Rs. 10.64 billion	COD	October 2000
US dollars (1997)	US\$ 285 million	Gas conversion	September 2001
Debt-to-equity ratio	70:30	PPA Term	15 years
		Ownership	BOO
Sponsors	Lanco Group (domestic); Genting Group (Malaysian)		
Other equity holders	CDC Globeleq (UK); Doosan Heavy Industries and Construction (Korea);		
EPC Contractor	Korea Heavy Industries and Construction (Hanjung; now Doosan)		
Operator	Genting Lanco Power (India) Pvt. Ltd. ¹⁵⁷		
Multilateral involvement	Korean ECA		
Offtaker	AP Transco (formerly APSEB)		
Lenders (Present)	Industrial Finance Corporation of India (IFCI); Power Finance Corporation (PFC), Industrial Development Bank of India (IDBI), Life Insurance Corporation (LIC), General Insurance Corporation (GIC), Bank of Baroda, State Bank of India, Canara Bank, Bank of India, ING Vysya Bank, Dena Bank.		
Lenders (Financial Closure)	Industrial Finance Corporation of India (IFCI); Power Finance Corporation (PFC), Industrial Development Bank of India (IDBI), Life Insurance Corporation (LIC), General Insurance Corporation (GIC), Bank of Baroda, Vysya Bank, IndusInd Bank, Dena Bank		

I. OVERVIEW.

The 368.144 MW Lanco Kondapalli plant in Andhra Pradesh is the third major IPP in Andhra Pradesh. Developed by local sponsor Lanco Group, with international partners Genting Bhd. (Malaysia), CDC Globeleq (UK) and Eastern Generation (UK), the Kondapalli project was competitively bid on the basis of a single tariff (as opposed to earlier bidding, which relied on bids for project cost). The relationship with state offtaker AP Transco has included some disputes. Despite these bumps, payment has been consistent, debt-service uninterrupted, and returns for investors seem to have been relatively stable.

Kondapalli Development Timeline	
June 1995	First discussions
Nov. 1995	Request for qualification
Apr. 1996	Price bid submitted
Jul. 1996	Letter of intent signed
Mar. 1997	PPA signed
July 1997	EPC contract signed
Jan. 1998	TEC approval from CEA
Dec. 1998	Financial close
June 2000	COD Unit I
July 2000	First invoice to AP Transco
Sept. 2000	COD Unit II
Sept. 2000	First payment from AP Transco

¹⁵⁷ A joint venture between Genting Group and Lanco Group.

Lanco Kondapalli was a second generation, tariff-bid IPP. Lanco is the only one of six tariff-bid projects in Andhra Pradesh to reach commercial operations (in October 2000). The tenders for these projects included a clause that required financial close by December 1998 – only Lanco was able to meet the requirement, which was possible in part due to the Lanco Group’s strong relationship with Indian banks and to support from other equity sponsors, CDC Globeleq and Eastern Generation.

II. PROJECT STRUCTURE.

A. Stakeholders.

Kondapalli’s core sponsors are the Lanco Group (“Lanco”)(a local Hyderabad company), CDC Globeleq and Eastern Generation (UK), Genting (Malaysia) and Doosan Heavy Industries & Construction (Korea). The Lanco Group has promoted seven IPPs, five of which are operational. Other than Lanco Kondapalli & Aban Power, however, Lanco’s other generators are renewable energy projects of less than 15 MW each. Eastern Generation sold its equity to NRG (USA), which was in turn, bought over by Genting (Malaysia). Beyond this transaction, the equity interests have not changed in percentage terms.

Kondapalli Equity Structure	
Lanco Group	33.9%
Genting Bhd.	30%
CDC Globeleq	25.1%
Doosan	11%

B. Power Sales Arrangements.

Kondapalli sells all of its capacity via a 15 year PPA with AP Transco, the state off-taker in Andhra Pradesh. The plant is run as a base load plant, fully dispatchable but with a take-or-pay floor set at 80% PLF. (With some contractual and technical constraints laid down in the PPA).

Lanco Kondapalli’s foreign currency requirements are in the form of principal repayments, interest payments; O&M related expenses etc. LKPPL tariff is a two-part tariff and contains both rupee component and dollar components, which compensates to a large extent the foreign exchange risk.

C. Financial Arrangements.

Kondapalli is financed almost entirely from domestic Indian financial institutions with long-term rupee denominated loans. The loan repayment period is 12 years. KEXIM is the only foreign lender, supporting the EPC work of contractor Doosan. Subsequently, Kondapalli refinanced the high cost K-EXIM debt with Foreign Currency Loans from State Bank of India, Bank of Baroda and Canara Bank.

Kondapalli secured financing in December 1998, as per a requirement in the original tender documentation. It was the only one of six tariff-bid projects to achieve financial closure in time, which protected Kondapalli's ability to resist government pressure to lower its tariff. Although the Asian financial crisis did not affect the Indian economy significantly, securing financing in Asia at this time was difficult. In order to secure financing, the usual limited or non-recourse project finance terms have been expanded to provide additional recourse for the Indian bank lenders. All lenders have first right on the company assets, and several "full recourse" lenders were provided a corporate guarantee by the Lanco Group, as well as personal guarantees from various directors on the Kondapalli board.

D. Fuel Arrangements.

Kondapalli obtains natural gas via a Gas Supply Contract (GSC) signed in August 2000 with GAIL, the Indian state-owned natural gas utility. The gas is sourced from various fields located in the Krishna Godavari Basin ("KG Basin") and supplied through a 200 Km pipeline. The GAIL contracts cover 100% of Kondapalli's capacity. Kondapalli has fired exclusively on natural gas since September 2001. Previously, the project had been built to fire on naphtha. When naphtha prices were deregulated in the late 1990s and began rising precipitously, the switch to natural gas became critical. Kondapalli covered the costs of transforming the plant to natural gas. Since incurring these costs, the project has not been allowed to recover the costs of the transition by passing it through in its tariff.

As discussed below, the fact that Kondapalli had secured financing by December 1998, thus complying with project requirements in the original tender, allowed the project to resist government pressure to renegotiate when naphtha prices began climbing in the late 1990s. A second element of this episode is that the six tariff-bid projects had rights to gas allocations from GAIL that vested only upon achieving financial close—Kondapalli thus had a low cost alternative to naphtha, and was protected from competing for scarce gas allocations from a position of vulnerability.

E. Government Support and Security Arrangements.

Kondapalli enjoys the protection of an escrow arrangement, whereby AP Transco's revenues pass through a third-party escrow account where IPP payments are deducted, before arriving in AP Transco's bank accounts. Government officials have expressed frustration with these arrangements, feeling that they provide excessive protection for the IPPs, and constraining government official's capacity to resolve disputes (*see below*).

In light of the fragile financial health of APSEB (AP Transco's predecessor) at the time of bidding, lenders required escrow protection (as in many other Indian IPPs). AP Transco operationalised the escrow mechanism only in October 2003. Since that time, flows into the escrow account are sufficient to meet the monthly bill amounts raised by Lanco.

III. HOST COUNTRY CONTEXT: ANDHRA PRADESH.

The Andhra Pradesh electricity sector, while representative of India generally in many respects, emerged as a leader in reform efforts during the 1990s. Relative to other SEBs, the state utility has maintained a positive, if not stellar, performance record. Andhra Pradesh has recently ranked number one in independent reviews of state power sector performance.¹⁵⁸ In 2000, installed capacity in Andhra Pradesh had reached almost eight gigawatts and per capita consumption was 391 kilowatt hours, compared to 355 kilowatt hours on average in India. Hydropower and coal fired plants account for the majority of the generating capacity in the state, although dependence on combined cycle natural gas-fired projects has grown tremendously, primarily via the installation of private generators.

In 1998, the Andhra Pradesh unbundled its SEB into a generation company, APGenco, and a transmission and distribution company, APTransco, which also acts as the offtaker from IPPs. APTransco was further divided into a transmission company and four distribution companies in 2000.¹⁵⁹ Genco controls roughly 70% of installed capacity, with the rest coming from IPPs, cooperative power projects and captive generators. Technically, performance is mixed—the generation sector in Andhra Pradesh has averaged the highest plant load factors in India, but the transmission and distribution sectors often fritter away any potential gains with high losses and poor billing performance. Tariffs remain highly cross-subsidized, with prices for industry among the highest in India, yet almost non-existent for agriculture (e.g. in 1997-98, agricultural users accounted for 48% of sales, yet only 4% of revenue).¹⁶⁰

Policymakers in Andhra Pradesh sought to place the state's electricity sector at the vanguard of reform in India. The state was an enthusiastic participant in the early development of IPPs—two of the original eight fast-track IPPs (GVK and Spectrum) are in AP, both of which achieved commercial operations. In 1998, the state passed an electricity reform law that unbundled the state electricity board into generation and transmission units, and established an independent regulator.¹⁶¹

IV. PROJECT PERFORMANCE.

A. For Investors.

Kondapalli has faced several notable challenges in the construction, operation and management of the plant. Nevertheless, the original contract terms are intact and project officials note that the plant has serviced its debt so far with no default, and suggest that

¹⁵⁸ Government of India, Ministry of Power, *Rationale for Andhra Pradesh State Power Sector Scoring* (2003); CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

¹⁵⁹ Id.

¹⁶⁰ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998)

¹⁶¹ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Andhra Pradesh, India*, PESD Working Paper #20 (2004).

the project's equity holders have been satisfied with project performance, including financial performance.

The most serious problem arose when the project was caught in the crosshairs of gas politics in India. Originally, all six tariff-bid projects were planned with naphtha as primary fuel. Within two years of the original bids, naphtha prices had more than tripled. As a result, the AP government advised the tariff based projects (including Kondapalli) to switch to natural gas as primary fuel and natural gas allocations to the projects. Based on the recommendations of Government of AP and AP Transco, Lanco Kondapalli obtained an allocation of natural gas in June 2000.

As noted above, however, the other projects were not able to do the same. This difference reflects the fact that Kondapalli was further down the path to commercial operation—particularly the involvement of commercial banks and the vesting of the projects rights to a GAIL gas allocation. The additional contractual layers following financial close and the start of construction placed meaningful constraints on the government's ability to reduce the tariff. The remaining five plants on the other hand, were in a weak position because they had already failed to meet the contractual deadline, and were facing an inability to get natural gas to fire their plants. All four lowered their tariff to lowest bid. None of these plants is operational yet.

A brewing conflict threatens the relative stability of Kondapalli's operations. The AP government has convened a committee to review PPAs of three of the IPPs – GVK, Spectrum, and Lanco Kondapalli – to deliver on a campaign promise by the recently elected Congress Party government. While renegotiation, discussions were being held between the IPPs and the government committee regarding reduction of fixed costs for the projects. AP Transco vocally continued to demand lower fixed cost, in view of the political acrimony of the dispute.

B. For the Host Government.

Andhra Pradesh has seen IPPs developed in each of the successive private power regimes in India. Two cost-plus fast track projects are operating (GVK, Spectrum), several projects bid on the basis of cost are still in limbo, and one (out of six) tariff-bid project is operating—Lanco Kondapalli. As a symbol of the benefits of continuing experience with private power, and of relying on competitive bidding, project outcomes for Andhra Pradesh seem to be relatively positive.

Nevertheless, government officials have stated dissatisfaction with Kondapalli in two primary areas. First, according to interviews and figures provided by the state offtaker, Lanco's first bid contemplated a Rs. 1240 crore project cost. The tariff bid, based on levelized tariff cost, worked out to a rate of Rs. 2.82/kwh. On this basis, the PPA was signed on March 31, 1997. When project costs came before the CEA for approval, total approved project cost was Rs. 1027 or 1035 Crore (excluding margin money for working capital), lower than the project cost reflected in the tariff bid. During post-bid negotiations, the levelized tariff was lowered to Rs. 2.57/kwh to reflect the

revised project cost of Rs. 1064 Crore (Rs. 1035 Crore + working capital margin of Rs. 29 Crore). APTransco, apparently seeking an even lower rate, filed a notice stating that it would only pay based on the tariff resulting from CEA's approval. Lanco argued against this position, stating that because Lanco Kondapalli is a tariff bid project, the bid tariff in the PPA should govern. Lanco successfully sought a stay in court against APTransco's notice and APTransco is currently paying the original tariff rate while the matter is litigated.

Lanco's version of the dispute emphasizes a misunderstanding regarding whether to revise the cost estimate for the project and whether doing so was even relevant, as the project was tariff-bid, not cost-bid.

Second, the Lanco PPA also contemplates installed capacity of 368.144 MW, which must be rated and certified based on calculations that take into account site conditions, such as ambient air temperature. According to interviews with AP Transco, application of this formula leads to an actual installed capacity rating of 351 MW, but AP Transco pays based on a rating of 368.144 MW. This dispute was referred to the regulator and is now in court. Lanco obtained a stay against the regulator in this case as well. Arbitration is viewed as a last resort. These disputes suggest that while Andhra Pradesh is often viewed as a relatively investor-friendly state for IPPs, the government and IPPs have had their share of smaller disputes, which reflect state official's ambivalent position toward the much needed private power producers that are nevertheless viewed as expensive and inflexible.

Lanco's response to the installed capacity dispute is that AP Transco has misinterpreted the relevant PPA provisions. Per the contract, the Installed Capacity quoted in the bid is nominal capacity with a tolerance limit of + or - 5%. Lanco demonstrated installed capacity at 368.144 MW as per the provisions of the PPA in the presence of experts identified by AP Transco in November 2001 which is well within the permissible tolerances specified in PPA. In this account, AP Transco suddenly adopted a different interpretation of the PPA provisions and seeks to pay as per this new interpretation.

As of August 2005, these matters were awaiting adjudication.

Gujarat Paguthan Energy Corporation Private Limited

Gujarat

Specifications			
Capacity	655 MW	PPA	1993, 2003
Fuel	Naphtha / Natural Gas	Financing	1996
Technology	Combined Cycle	COD	December 1998
Project Cost (1993 FX)	US \$734 million	PPA Term	20 years
Ownership	BOO		
Sponsors		Original promoters: Torrent (domestic); Powergen (UK)	
Other equity holders		China Light & Power (CLP) bought Powergen's stake and gradually acquired 100% ownership; Siemens (EPC)	
EPC Contractor		Siemens	
Operator		Powergen / CLP	
Multilateral involvement		n/a	
Offtaker		Gujarat Electricity Board	
Lenders		KfW (Germany); Bayerische Landesbank (Germany); and a consortium of Indian lenders lead by IDBI	

I. PROJECT OVERVIEW.

The Paguthan power plant (“Paguthan”) is a 655MW natural gas fired IPP in the Indian state of Gujarat. The project was originally conceived by the Gujarat Electricity Board (“GEB”) in the late 1980s in order to take advantage of the development of nearby gas fields. Although Paguthan has undergone substantial equity turnover, the project appears to be performing relatively well, although current owner China Light & Power of Hong Kong does report some difficulties arising from renegotiations with Gujarat authorities. Paguthan was one of the first private plants in India to secure private fuel supply on an entirely commercial basis, as has benefited from the provision of low-cost domestic natural gas.

II. PROJECT STRUCTURE.

A. Sponsors.

In the early 1990s, the Paguthan project was given to Torrent, a local firm which had run electricity distribution licensees in Gujarat and owned a pharmaceutical business. Powergen joined the project with a minority share but made it clear that they would be an active investor. Siemens was selected as EPC contractor and joined with a small equity stake. The Gujarat Government also participated in equity through Gujarat Power Corporation Ltd, but remained very passive in the development and operation of the project. Local partner Torrent’s participation allowed for provision of local expertise, while the foreign partner’s brought experience in O&M and developing large power generation projects.

Powergen acquired the Torrent share in late 1999, when the latter was restructuring.¹⁶² Powergen also bought Siemens' stake in keeping with Siemens' original exit strategy of picking up equity to demonstrate commitment to project and selling after COD. In late 2000, Powergen's board decided to sell all of its international IPPs to fund U.S. acquisitions and focus on the U.S. and U.K. markets. CLP bid for all of Powergen's Asian assets (in India, Thailand, Indonesia and Australia) and in the end bought all of the projects except those in Indonesia. CLP had an 88% stake in Paguthan originally, and later acquired the original GPCL stake as well. Since 2002, CLP has been 100% owner of the project.

B. Power Sales Arrangements.

Paguthan sells all of its capacity to the Gujarat Electricity Board under a 20 year PPA. The PPA provides a return on equity that is partially indexed to hard currency (a portion of equity returns equivalent to original hard currency equity contributions are indexed and paid at prevailing exchange rates). The equity returns and other fixed charges are subject to the plant achieving contractual availability targets. Fuel charges are paid according to actual generation based on required efficiency targets. The PPA has a provision that sets deemed generation (similar to "take-or-pay" requirements) up to 90% availability. The plant is dispatched as a base load station—records posted by the Indian Power Ministry indicate recent dispatch in the range of 75-80%.

The power sales arrangements were to be supported with an escrow arrangement over certain revenues of the GEB as well as letters of credit. Neither arrangement was fully implemented, although project managers have questioned the utility of such mechanisms even where they are implemented. The project enjoys a guarantee from the Gujarati state government for the payment obligation of GEB up to Rs1200.00 crore.

In December 2003, the parties amended the PPA, in order to (i) reduce the tariff; (ii) reduce O&M costs; (iii) reduce PLF incentives; and (iv) reflect reduced interest rates. This amounted to a relatively small reduction in the base tariff, plus a significant reduction in pass-through costs (overall a tariff reduction of roughly 20%). According to one report, the company viewed these discussions and amendments as positive and in the long-term best interest of the parties. Conspicuously, these adjustments were not made in response to an election agenda, which has often been the case in other states. The Gujarat Electricity Regulatory Commission did not oversee the process because the original PPA was signed before the GERC was constituted.

With firm gas linkages (*see below*) and the move away from expensive naphtha, the Paguthan tariff came down. The GEB's finances were also improving. Throughout the life of the Paguthan project, the GEB maintains that it has paid its dues, even during the naphtha crisis period. However, other sources indicate that the project has had problems with GEB arrears, problems that were echoed in CLP's annual reports.

¹⁶² Torrent has since re-entered the Gujarat power market, with a project coming up in Surat fueled by LNG.

C. Financial Arrangements.

The project was financed on a project basis along lines typical for developing country IPPs (i.e., with 70% debt and 30% equity). Foreign currency loans constitute almost 80% of the total loan package, and carry guarantees from several Indian banks. Financing came from a syndicate of German banks, along with support from the German export-credit agency (to support the sale of Siemens technology). The project has not been refinanced.

D. Facilities and Construction.

Paguthan runs in combined cycle, and consists of three generating units—two gas and one steam. Powergen built the plant to international standards and took an active role from the beginning, which helped lenders gain confidence in the project. According to the company, fixed costs were low on a per megawatt basis compared to most other gas-fired IPPs developed in India. Paguthan was also reportedly one of the only projects for which actual capital costs came in below the CEA approved costs. There were no major issues during construction, and Siemens and Powergen worked well together. The contractors finished the project ahead of schedule with no cost overruns, which helped to bring down overall fixed costs. The project achieved commercial operation in December 1998.

D. Fuel Arrangements.

A major challenge arose when naphtha prices went through the roof in the late 1990s, causing the Paguthan tariff to become unaffordable due to high variable fuel costs. In 2000, for some duration the GEB decided not to dispatch power from Paguthan and only made capacity payments. In order to bring down their tariff and compete in the merit order dispatch, Paguthan accelerated efforts to secure a natural gas linkage.

The project bid for a private gas contract with a consortium (consisting of ONGC, Tata and Cairn Energy) developing the Lakshmi gas field, located off the coast of Gujarat near Hazira. According to former project management, Powergen won the contract following commercial negotiations, with the government playing no role in the awarding of the contract. Paguthan thus became the first IPP to negotiate a purely private gas contract with take-or-pay provisions. The take-or-pay obligations ran both ways, so that if the Lakshmi consortium failed to meet their firm commitment for gas supply, they would pay damages. Gujarat State Petronet Limited (“GSPL”), which markets and sells the gas from the (distinct) Petronet LNG terminal and already operated gas pipelines, developed a multiple user pipeline that ran to the facility and eventually onward to Ahmedabad, with Paguthan as its primary customer. It took 12 months to build the 100 kilometer pipeline to move the gas from Lakshmi to Paguthan. In October 2002, GSPL completed construction of the pipeline and gas came online for the facility.

Gas supplied under the Lakshmi contract was not meeting the full gas requirements of the project, however, so Paguthan tied up two additional private gas

contracts. The first was a take-or-pay contract with the joint venture between the Gujarat State Petroleum Company and Niko, which owned rights to an onshore gas field in Hazira. The project tied up the balance with Petronet LNG, which is marketed and sold by GSPL (a consortium between GAIL, BPCL and ONGC). The project company is pleased to have a supplier (GSPL) with multiple contracts to source its gas, thereby mitigating Paguthan's downstream risk. The majority of Paguthan gas is from Lakshmi (70-75%), with the remaining gas sold under the smaller volume contracts mentioned above.

III. HOST COUNTRY CONTEXT: GUJARAT.

Gujarat is one of the most developed and industrialized states in India, a factor that is reflected in the profile of its electricity industry. In 2000, per capita consumption of electricity was 835 kilowatt hours, as compared to an average of 355 kilowatt hours for India overall. Overall, consumption has quadrupled between 1980 and 2000, from 8 trillion kWh to 33 trillion kWh. However, consumption is still heavily agricultural, with 40% of demand coming from the agricultural sector. Installed capacity was almost nine gigawatts in 2002, of which 27% was provided by private generators.¹⁶³

In terms of performance, the GEB seems typical for a state electricity board in India. Through the mid-1990s, revenues amounted to only one-fourth of annual revenues—with the balance coming largely from government subsidies. Tariffs remained highly subsidized, particularly for agricultural consumers, although in line with most of India.¹⁶⁴ As a state, Gujarat placed seventh in a pool of 26 SEBs ranked by the debt rating firm CRISIL in 2003 for state power sector performance.¹⁶⁵

Gujarat has not been a leader in reform efforts. The major activity in the development of the IPP sector came in the mid-1990s (a fact that may have helped Gujarat avoid some of the mistakes of other states that had pioneered reform). Subsequently, in 1998, following the enactment of the national Electricity Regulatory Commissions Act in 1998, Gujarat established an independent regulator (GERC) to oversee the electricity markets and reform tariffs. Efforts continue in this arena, with the passage of a state reform statute in 2003 and unbundling of the state utility in 2005.

IV. PROJECT PERFORMANCE.

A. For Investors.

The Paguthan project seems to have performed somewhat below expectations for project sponsors. While both Powergen and Siemens exited the project for strategic reasons (i.e. the former in order to refocus on their core business in the US and Europe,

¹⁶³ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Gujarat, India*, PESD Working Paper #21 (2004).

¹⁶⁴ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998).

¹⁶⁵ CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

and the latter because they originally assumed an equity position only as part of their EPC work), CLP has reported publicly some troubles enforcing the terms of the PPA, as well as the need to reach agreement on new terms in some cases. Available information is not sufficient to speculate regarding the severity of these problems.

Nonetheless, despite these problems, the investment in Paguthan appears to have been a profitable one (although lower than expected), and hence, CLP appears to be positive about the future of the Indian electricity sector and is currently developing a 1050 MW expansion of the Paguthan project, making it the only foreign developer that is far along in the development of a new large scale IPP. For Phase II of Paguthan, CLP is looking to take advantage of multiple offtakers (now permitted under the 2003 Electricity Act), although it believes the time has not yet arrived for electricity trading and merchant operation.

B. For the Host Government.

The Ministry of Power reports that Paguthan came in with a fixed cost of Rs. 3.509 crore / MW, which places the project in the low-middle range of fixed costs for IPPs in India, and in the low range for gas-fired projects. Data maintained by the Central Electricity Authority indicates recent dispatch of between 70-85% of capacity, a relatively healthy number.

Beyond pure cost considerations, the Paguthan project offers several other attractive features. The private fuel contracts have pioneered the development of private fuel markets in India. The project also has invested substantial amounts in environmental protection, utilizing dry-cooling towers, and was accredited with ISO 14001 certification in 1999.

Essar Steel, Essar Power Project

Gujarat

Specifications			
Capacity	515MW (215MW captive)	PPA	1996
Fuel	Naphtha / Natural Gas	Financing	n/a
Technology	Combined Cycle	COD	1997
Approved Cost (1995)	US\$ 514 million	PPA Term	20 years
Sponsors			Essar Group
EPC Contractor			Essar project ltd.
Operator			Essar power ltd
Multilateral involvement			n/a
Offtaker			Gujarat Electricity Board
Lenders			IDBI (domestic); DBI (domestic); U.S. Eximbank

I. PROJECT OVERVIEW

The Essar Power Limited (“Essar”) is a partially captive power plant that sells its output to an adjacent steel plant and to the Gujarat Electricity Board (“GEB”). Essar grew out of efforts by Essar Steel to build captive generation to fuel production of hot briquette iron; the steel plant originally needed only 30 MW of power, so Essar constructed a 30 MW captive CCGT plant from 1992 to 1994. When Essar decided to put in a steel furnace, the Essar Steel Plant required another 215 MW of electricity. Essar approached the state for approval to expand its captive capacity, and the state responded by proposing a larger plant for use as a hybrid captive/IPP facility. Essar agreed to build a 515 MW project, with 300 MW dedicated to the GEB and the balance used by Essar Steel. The plant has been operating on the open cycle mode since August 1995, and combined cycle since October 1997.

II. PROJECT STRUCTURE.

A. Sponsors.

The Essar Group is one of India’s largest corporate conglomerates with an asset base of over US\$4 billion and a US\$2 billion turnover annually. Essar Steel is in the business of producing hot rolled coil and hot briquette iron. The steel plant (“Essar Steel Plant”) adjacent to the Essar Power IPP is the world's largest gas-based producer of sponge iron. A separate project company was formed, with equity only held by Essar Group companies and affiliates. At an early stage, lender issues arose because banks were reluctant to loan to a company with no private generating experience (other than the 30 MW captive power plant). Essar’s existing creditors had already extended full lines of credit for other projects and the Essar Group had previously restructured its debt with Indian lenders. As a result, Essar had to approach new lenders and finance the project on the sponsors’ balance sheet.

B. Financial Arrangements.

The project cost was roughly Rs. 24 billion (approx. \$500 million at current exchange rates).¹⁶⁶ In structuring the financing, Essar Steel agreed to supply a disproportionate amount of the project cost through its balance sheet (as against its proportion of dedicated capacity). IDBI and DBI provided domestic loans, with U.S. dollar loans extended by U.S. Eximbank (the project utilized GE turbines). Eximbank, however, did not disburse funds until after COD.

C. Fuel Arrangements.

In the project's initial period of operation, it burned a variety of fuels, primarily NGL (a petroleum derivative fuel) from 1995-1998 (ONGC did not have a facility for creating naphtha) and then a mixture of gas (about 60-70%) and naphtha from 1998 until 2004. Essar Power attempted to buy fuel from Gujarat Gas (a consortium led by British Gas), but the state reportedly did not approve the contract because it felt a cheaper fuel source was available. During this interim period, the project's gas supply came from gas already online for the Essar Steel Plant. While burning on a combination of naphtha and gas, the GEB was only using 30-50% of its designated capacity on account of high variable costs. When naphtha prices increased, Essar still managed to run with tariffs 10% to 20% lower than other IPPs burning naphtha due to its own dedicated pipeline for naphtha and geographic advantage with respect to Hazira oil terminals and by taking advantage of exemptions on state taxes on naphtha. The GEB still met its obligations, however, and at worst was only three to six months behind in payments. In 2004, Essar Power entered into a contract with GSPCL for purchase of gas from the Petronet LNG terminal.

D. Power Sales Arrangements.

The 515MW plant has 300MW dedicated to the Gujarat Electricity Board, and 215MW designated for captive offtake by the Essar Steel Plant. The power sales agreement entered into for 20 years with both customers ensures recovery of fixed cost as well as the sponsors' return on equity at 70% plant availability irrespective of actual off take. The monthly payment of fixed cost is indexed to account for foreign currency fluctuations. Under the power sales agreement, fuel cost is a variable pass-through element reimbursable and paid based on actual off take of energy by the customer. Essar Power is fully dispatchable—meaning that the plant's load can be adjusted as per the energy requirement of the customers, so long as the take-or-pay payments are made.

The power sales arrangements were to be supported with an escrow arrangement over certain revenues of the GEB. This escrow arrangement was never implemented, although project managers have questioned the utility of such mechanisms even where they are implemented. The project enjoys a letter of credit for the purchase of natural gas that will go to electricity for GEB export to other states, but no other official credit support for the GEBs obligations under the PPA.

¹⁶⁶ However, this figure does not comport with the 3.15 crore fixed cost per megawatt also cited, or the 3.24 crore per megawatt cost reported by the Ministry of Power.

E. Facilities and Construction.

The construction period proceeded without delays or cost overruns, even though the project was the first to use gas turbines of this size to fire naphtha. Essar handled the civil works in-house through Essar Projects Ltd. The one and a half year delay between open cycle mode and combined cycle mode was planned, given the long period required to build the boilers for steam generation.

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IV. PROJECT PERFORMANCE.

The Essar Power PPA was renegotiated once in August 2003. The renegotiated terms primarily involved reductions in a number of pass-through variable costs, including interest rate reductions through refinancing and fuel cost reductions through the switch to gas. Essar has since refinanced and paid off its dollar-denominated loans.

¹⁶⁷ P.R. Shukla, Debashish Biswas, Tirthankar Nag, Ameer Yajnik, Thomas Heller and David G. Victor, *Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Gujarat, India*, PESD Working Paper #21 (2004).

¹⁶⁸ Infrastructure Development Finance Corporation, *State Electricity Boards: A Selective Overview* (1998).

¹⁶⁹ CRISIL and ICRA, *Report on the Rating of State Power Sectors*, January 8, 2003.

Management at Essar Power cites several advantages for the IPP. First, its hybrid approach to power generation, mixing captive power capacity with IPP capacity, allowed it to weather demand fluctuations more easily. When naphtha prices were high and GEB offtake low, the steel demand remained strong, which allowed the project to run two to four units and maintain a 60% to 70% PLF. After the 2002 downturn in the steel industry, the GEB began taking more power, which has increased greatly since 2004.

Project stakeholders suggest that the plant's hybrid structure has served it well in this unstable market; because of demand at the steel plant, Essar Power has 70-80 MW of non-fluctuating load. This helps improve plant stability, and the plant has reportedly never had a full station shutdown. Further, Essar is able to serve a smoothing function for peaking versus base load generation by meeting unexpected demand spikes because it is always ramped up for its steel production.

In interviews in Gujarat, the Essar Power IPP was evaluated favorably from the standpoint of its promoters and lenders. The hybrid strategy mitigated project risk by diversifying revenue sources. Managing cost by leveraging the benefits of building for a captive consumer, as well as the benefits of switching to natural gas, has allowed the project to occupy a strong niche in the Gujarat electricity market. Currently Essar Power is developing a 1500 MW project in Hazira, for which it has nearly obtained the requisite approvals. The new project will be majority controlled by the Essar Group and aims to take advantage of LNG linkages.