A Political Economy of International Infrastructure Contracting: Lessons from the IPP Experience

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The Program on Energy and Sustainable Development at Stanford University is an interdisciplinary research program focused on the economic and environmental consequences of global energy consumption. Its studies examine the development of global natural gas markets, reform of electric power markets, international climate policy, and how the availability of modern energy services, such as electricity, can affect the process of economic growth in the world's poorest regions.

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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 ten developing and reforming countries (Argentina, Brazil, China, India, Malaysia, Mexico, the Philippines, Poland, Thailand and Turkey). PESD has also helped to develop 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

Erik Woodhouse was a Postdoctoral Fellow with the Program on Energy and Sustainable Development during 2004-2005. His research focuses on energy infrastructure investment in developing countries. Other recent research includes work in comparative corporate governance and law in international relations.

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[*] Postdoctoral Fellow, Program on Energy & Sustainable Development, Stanford University. This paper reports the results of a study undertaken by the Program on Energy & Sustainable Development ("PESD") at Stanford University, and would not have been possible without the leadership and support of Dr. David Victor at PESD and Professor Thomas Heller at Stanford Law School, as well as the dedicated work of PESD researchers who led country and project studies: Peter M. Lamb, Pei Yee Woo, Katia Olexiyivna Karpova, Jeff Rector, Joshua C. House, Efe Cakarel, and Alejandra Nuñez-Luna. PESD also collaborated with Anton Eberhard and Katharine Gratwick at the University of Cape Town, who contributed invaluable insight with a study on the IPP experience in Africa, and with Dr. Adilson de Oliveira, Luciano Losekann, and Felipe V.S. Araujo at the Universidade Federal de Rio de Janeiro on research into the Brazilian IPP experience. For invaluable discussions, support in arranging contacts and field research, and helpful comments on drafts, the author would like to thank Anthony Becker, Mario Veiga Pereira, Jessica Farmer, Bart Lucarelli, Myrna Velasco, Sundar Sundaresan, Jeff Meller, John Schuster and Gerald West. Errors are the author's own.

I. INTRODUCTION

Developing countries are anticipated to need $5 trillion of investment to meet expected demand for electricity by 2030, with more than $2 trillion for new generation capacity alone.[1] For most countries, mobilizing sufficient investment is beyond the capacity of the government itself; the majority of developing countries will rely on some form of private investment to meet this demand.[2] Yet, private investment in public infrastructure—already an enormous market in the 1990s—has proven to be a traumatic experience for host countries and for investors alike. From a high of $46 billion in 1996, private infrastructure investment in emerging economies dwindled to $15 billion by 2003, and is only recently beginning to show signs of recovery.[3] Popular perception views the private infrastructure landscape as littered with wreckage—especially for investments in electric power infrastructure and notably for investors who have been victims of government opportunism and corruption.[4] Despite lengthy debate and examination of these issues, the key lessons from the 1990s cycle of investment remain vague and ill-focused to inform the next round of decisions by investors and policy makers that are now taking shape.

This paper presents the conclusions and analysis of a detailed study of the experience of investment in greenfield independent power projects ("IPPs") in developing countries.[5] The term "independent power producer" has been used to refer to

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[1] INTERNATIONAL ENERGY AGENCY, WORLD ENERGY INVESTMENT OUTLOOK 2003, at 364 (2003); *see also* DELOITTE TOUCHE TOHMATSU, SUSTAINABLE POWER SECTOR REFORM IN EMERGING MARKETS: FINANCIAL ISSUES AND OPTIONS, Joint World Bank/USAID Policy Paper (June 2004), at ix [hereinafter DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM] (estimating that developing countries will need $140-160 billion of investment in power annually through 2025 to meet projected electricity demand).

[2] DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* ("[A]ssuming that 40% to 50% of power sector investment in emerging markets … comes from self-financing, this still leaves an additional investment need of about US $50 billion to $70 billion per year, which policy makers would seek to attract from the private sector.").

[3] Data from the World Bank Public Participation in Infrastructure Database, *available at* http://ppi.worldbank.org [hereinafter World Bank PPI Database].

[4] *See, e.g.*, Louis T. Wells & Eric Gleason, *Is Foreign Infrastructure Investment Still Risky?,* HARV. BUS. REV., (Sept./Oct., 1995); Tom Marshella, *Debt Financing of Projects in Emerging Economies: Lessons from Asia*, 7 J. OF PROJ. FIN. 30 (2001); Jacob J. Worenklein, *The Global Crisis in Power and Infrastructure: Lessons Learned and New Directions*, 9 J. OF STRUCT. & PROJ. FIN. 7 (2003).

[5] The research methodology for the project is reported in a working paper. *See* David G. Victor, Thomas C. Heller, Joshua C. House, Pei Yee Woo, The Experience of Independent Power Projects (IPPs) in

several types of enterprises,[6] but for this paper, an "IPP" refers to a privately developed power plant that sells electricity to a public electricity grid, often under long term contract with a state utility.[7] For this study, the lead actors in every IPP are private investors—usually foreign, but often with local partners. The classic foreign-sponsored, project-financed IPP has taken root in more than fifty emerging countries that display wide variation in economic, political and social environments.[8] The wide variation in settings for IPPs affords a special opportunity for researchers to probe systematically the critical factors that contribute to outcomes for host countries and for investors.

Assessing the IPP experience is important not only for understanding the prospects for private investment in infrastructure. It also contributes to a long body of literature on managing risk in environments where it is difficult for the parties to enforce contracts.[9] Power projects demand massive capital investment upfront—multiple billions of dollars in some cases—and offer a return through a stream of payments over a long period (up to 30 years) during which the investor relies on the host government and other counterparties to honor the original deal. These projects are often financed through special purpose vehicles on a limited-recourse basis, a structure that maximizes sensitivity to uncertainty,[10] because the lenders look only to the project company and its

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Developing Countries: Introduction and Case Study Methods, PESD Working Paper No. 23 (2003), *available at* http://pesd.stanford.edu/publications/20528/.

[6] For a brief overview, see Mangesh Hoskote, *Independent Power Projects (IPPs): An Overview*, Energy Themes, The World Bank Group (1995).

[7] This paper distinguishes this entity, a "classic IPP," from several other arrangements including wholly captive generation or state-developed projects that have adopted some aspects of private ownership. Captive generation refers to power plants that sell their capacity to private dedicated industrial power purchasers. At the other end of the spectrum, numerous state-controlled enterprises have attracted the moniker "IPP" for various reasons. Often these plants are managed by the quasi-public firms that emerged from a country's restructuring process; for example, the five generation companies created in China's most recent reform of the power sector are formally called "IPPs" although each firm is actually state-owned and state-controlled. This study does not address either captive generation or state-controlled investment, because such projects do not confront many of the issues that comprise the focus of our study, such as the ability of private investors to enforce contract terms.

[8] Victor et al., *supra* note 5, at 33.

[9] For an overview of these issues, see Theodore H. Moran, *Political and Regulatory Risk in Infrastructure Investment in Developing Countries: Introduction and Overview*, paper presented at "Private Infrastructure for Development: Confronting Political and Regulatory Risks, Sept. 8-10, 1999, Rome, Italy; Louis T. Wells, *Private Foreign Investment in Infrastructure: Managing Non-Commercial Risk*, paper presented at "Private Infrastructure for Development: Confronting Political and Regulatory Risks, Sept. 8-10, 1999, Rome, Italy. Perhaps the best known exploration of the relationship between institutional credibility is the 1994 piece by Levy and Spiller, *see* Brian Levy and Pablo T. Spiller, *The Institutional Foundations of Regulatory Commitment: A Comparative Analysis of Telecommunications Regulation*, 10 J. OF L. ECON. & ORG. 201 (1994). During the 1990s, the project finance model, and IPPs particularly, occupied a central place in the ongoing debate regarding the relationship between risk, institutions and investment. *See* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 132 ("The most well-established risk management framework in the power sector is the IPP project finance structure.").

[10] Project revenues are subject to a pre-determined allocation of project revenues to particular accounts dedicated to particular purposes or lenders; even small changes register loudly in the contractual structure that governs this allocation. Lenders often respond to developing country risk in a variety of ways that

revenue as collateral for loans.[11] Mindful of these risks, developing countries have often included special provisions designed to attract investment in greenfield IPPs, but such provisions were themselves part of broader power sector reforms that have proven politically difficult to implement and have introduced risks of their own.[12] Because they sell a critical and highly visible public good—electricity—power plants are particularly exposed to political and social risk. Because many countries have a long history of subsidizing electricity, private power plants are often at the forefront of the particularly challenging task of getting consumers to pay the full cost of service.

Much of the literature on managing risk for long-term investment has viewed these issues through the lens of the "obsolescing bargain."[13] Negotiating leverage in a large private infrastructure project shifts during the project life cycle. Initially, the government needs private investors and thus offers attractive terms. Once operational, the investors require a long amortization period to attain their expected return while the host government has already secured what it needs; the original bargain has become obsolete. Theory predicts that the host will force a change in terms—either by outright nationalization or by squeezing revenue streams as far as possible. As the incidence of wholesale expropriation declined,[14] subsequent development of the original obsolescing bargain hypothesis primed analysts to be wary of subtler attacks on project value, so called "creeping expropriation"—attacks that could be handled (so the story went) by careful contracting to close such loopholes and constrain government actions towards infrastructure investment.[15]

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increases this sensitivity. *See* Mansoor Dailiami and Robert Hauswald, *The Emerging Project Bond Market: Covenant Provisions and Credit Spreads*, World Bank Policy Research Working Paper 3095 (July 2003), at 10 (finding increasing stringency in project loan covenants as country risk increases); Benjamin C. Esty and William L. Megginson, *Creditor Rights Enforcement and Debt Ownership Structure: Evidence from the Global Syndicated Loan Market* (draft working paper, June 24, 2002) at 18 (finding that banks respond to developing country risk by arranging larger and larger lending syndicates—with each bank holding a smaller share of project debt). Additionally, as country risk deepens beyond the point of commercial viability, many sponsors and lenders turn to multilateral credit enhancements (such as guarantees from MIGA or OPIC) to increase the debt capacity of a particular project. One study finds that the availability of credit enhancements is the most significant variable associated with higher levels of debt in countries with weak institutional environments. Devapriya, K.A.K. and H. Wilhelm Alfen, *Role of Institutional Arrangements in Financing Project Companies in* Asia (draft working paper, Oct. 2, 2003).

[11] *See generally*, International Finance Corporation, Project Finance in Developing Countries, International Finance Corp. (1999).

[12] DAVID G. VICTOR AND THOMAS C. HELLER EDS., POLITICAL ECONOMY OF POWER SECTOR REFORM: THE EXPERIENCE OF FIVE MAJOR DEVELOPING COUNTRIES [page] (Cambridge University Press)(forthcoming, 2005) [hereinafter VICTOR & HELLER, POLITICAL ECONOMY OF REFORM].

[13] The obsolescing bargain was originally proposed by Raymond Vernon in 1971. *See* VERNON, RAYMOND, SOVEREIGNTY AT BAY: THE MULTINATIONAL SPREAD OF U.S. ENTERPRISES (1971).

[14] Michael S. Minor, *The Demise of Expropriation as an Instrument of LDC Policy 1980-1992*, 1 J. OF INT'L BUS. STUD. 25 (1994); Clive Harris, et al., Infrastructure Projects: A Review of Cancelled Private Projects, Public Policy for the Private Sector Note No. 252, The World Bank (2003).

[15] Linda F. Powers, *New Forms of Protection for International Infrastructure Investors*, in MANAGING INTERNATIONAL POLITICAL RISK (Theodore M. Moran ed., 1998); Theodore H. Moran, *Political and Regulatory Risk in Infrastructure Investment in Developing Countries: Introduction and Overview*, preliminary draft presented at "Private Infrastructure for Development: Confronting Political and

Investors in IPPs knew about these risks and had studied closely the earlier experiences with expropriation. Sensitive to bitter lessons from previous international investments that had fallen prey to the obsolescing bargain in the wave of nationalizations in the 1960s and 1970s, the architects of private participation schemes in the 1990s sought to improve the commercial and regulatory environment of the host country itself[16] as well as the incentive structure of particular transactions in order to bolster the stability of the long term contracts that served as the foundation for these investments.[17] A cottage industry of lawyers and financial advisors—project or structured finance specialists, privatization advisors, legal and regulatory reform consultants, and commercial arbiters—provided many of the tools that investors thought were necessary to solve these problems.[18] These tools facilitated the boom in infrastructure investment in emerging economies that is detailed briefly in Part II of this paper.

In exploring the historical record, previous studies on infrastructure investment have often employed large statistical reviews[19] and specific case studies.[20] Each method of analysis has proved valuable yet limited in its ability to inform general conclusions that are relevant for the future. The former offers the rigor of systematic and large data sets but suffers where key variables that relate to plant operations have been difficult to simplify and measure. The latter has corrected that problem by offering immense detail on actual experience, but it suffers from the standard problem that it is difficult to generalize from very small sample (often just one project). As a result, the literature has poorly documented the variation in outcomes across IPPs and has not been able to

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Regulatory Risks, Sept. 8-10, 1999, Rome, Italy [hereinafter Moran, *Risk in Infrastructure Investment*].

[16] *See, e.g.*, Alejandro Jadresic and Fernando Fuentes, *Government Strategies to Reduce Political and Regulatory Risks in the Intrastructure Sector*, paper presented at "Private Infrastructure for Development: Confronting Political and Regulatory Risks, Sept. 8-10, 1999, Rome, Italy.

[17] A good, if broad, overview of these innovations is provided in Jonathan Green, *Managing Risks in International Power Projects*, 672 PLI/Comm 669, Practising Law Institute (1993). Part IV.B., *infra*, discusses a range of these mechanisms in the context of the IPP experience specifically.

[18] Louis T. Wells, Jr., *The New International Property Rights: Can the Foreign Investor Rely on Them?*, *in* INTERNATIONAL POLITICAL RISK MANAGEMENT: LOOKING TO THE FUTURE (THEODORE H. MORAN AND GERALD T. WEST, EDS., 2005) at 87, 88. [hereinafter Wells, *The New International Property Rights*]

[19] On large statistical reviews, see sources in note 23 *infra*.

[20] For specific case studies, *see, e.g.,* Mark Kantor, *International Project Finance and Arbitration with Public Sector Entities: When is Arbitrability a Fiction?*, 24 FORDHAM INT'L L. J. 1122 (2001); Harold F. Moore, *Allocating Foreseeable Sovereign Risks in Infrastructure Investment in Indonesia: Force Majeure and Indonesia's Economic Woes*, 822 PLI/Comm 463, Practising Law Institute (2001); Harold F. Moore, *Restructuring International Projects: Lessons Learned from Indonesia*, 866 PLI/Comm 283, Practising Law Institute (2004); Piyush Joshi, *Dabhol: A Case Study of Restructuring Infrastructure Projects*, 8 J. OF STRUCT. & PROJ. FIN. 27 (2002); Robert E. Kennedy, InterGen and the Quezon Power Project: Building Infrastructure in Emerging Markets, Harvard Business School Case No. 9-799-057 (1999); Frank J. Lysy, *Pagbilao Thermal Power Plant – The Philippines*, *in* INTERNATIONAL FINANCE CORPORATION, RESULTS ON THE GROUND: ASSESSING DEVELOPMENT IMPACT 13-32 (1999); Gary S. Wigmore and Desiree Woo, *Running the Marathon: The Long March to the Successful Completion of Miezhouwan*, *in* PROJECT FINANCE MODELS FOR GREATER CHINA (Asia Law & Practice, 1999).

identify fully the factors that explain why some projects are successful while others founder.

Of particular concern is the fact that existing studies of infrastructure investment overwhelmingly focus on capital mobilization (usually heralded by financial closing) as the indicator of success.[21] As a result, the literature is deficient in examining project performance over time;[22] yet many projects vary in performance with time, especially in the aftermath of an economic crisis. Those studies that have attempted a dynamic assessment typically remain at a very broad level of abstraction, which has contributed to generally dismal diagnoses of the prospects for private infrastructure investment.[23] Other literature, often from industry itself, focuses on the role of risks that are now perceived as impossible to allocate effectively, particularly massive foreign exchange crises and political risk.[24] Studies that focus on prescriptions for the future often focus exclusively on ways to engineer rules in the power sector and to set the "right" context for private investment.[25] Yet extensive power sector reform often undermines to prospects for IPPs,

[21] *See, e.g.*, Beatrice Weder and Mirjam Schiffer, *Catastrophic Political Risk versus Creeping Expropriation: A Cross-Country Analysis of Political and Regulatory Risks in Private Infrastructure Investments in LDCs*, paper presented at the World Bank conference "Private Infrastructure for Development: Confronting Political and Regulatory Risks," September 8-10, 1999, Rome, Italy (reviewing the literature that evaluates the connection between investment levels and risk indicators). More recent literature has begun to turn the corner, with only limited success. For example, one study of private power sector investment identified "successful private capital mobilization … which proved to be sustainable or … where sustainability was highly likely" as a key metric for project selection. Nonetheless, robust conclusions were difficult because many of the projects lacked a sufficient operating record for evaluation of sustainability beyond mere capital attraction, and because the selection only looked at projects deemed to be successful according to this metric. *See, e.g.,* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 34–35.

[22] These gaps persist for good reason. Information regarding project performance is notoriously difficult to obtain, and even more difficult to record systematically. Analysts therefore often focus on more readily visible indicators, such as financial close or contract enforcement. The emphasis on countries rather than on projects as objects of improvement may follow from this difficulty—very little is known about what elements of project structure worked well under pressure, making recommendations for improvement difficult to identify.

[23] *See, e.g.,* Antonio Estache and Maria Elena Pinglo, *Are Returns to Private Infrastructure in Developing Countries Consistent with Risks since the Asian Crisis*, World Bank Policy Research Working Paper No. 3373 (2004) (finding that average returns on infrastructure investment in developing countries, including 6% average return-on-equity for power sector investment, has generated equity returns far below the cost of equity); Sophie Sirtaine, Maria Elena Pinglo, J. Luis Gausch, and Vivien Foster, *How Profitable are Infrastructure Concessions in Latin America? Empirical Evidence and Regulatory Implications*, The World Bank Group (2004) (finding that while infrastructure concessions in a sample of ten countries have generated returns above their weighted average cost of capital, low distribution policies, possibly reflecting the ongoing investment requirements of concessions, have limited equity returns to a level far below the average cost of equity).

[24] Some of the more thoughtful and detailed of the reviews from the industry press include Tom Marshella, *Debt Financing of Projects in Emerging Economies: Lessons from Asia*, 7 J. OF PROJ. FIN. 30 (2001); Jacob J. Worenklein, *The Global Crisis in Power and Infrastructure: Lessons Learned and New Directions*, 9 J. OF STRUCT. & PROJ. FIN. 7 (2003).

[25] The literature on the relationship between host country governance, infrastructure sector performance and investment is vast. For examples of this point specifically, see DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1; PRIVATE SECTOR DEVELOPMENT IN THE ELECTRIC POWER SECTOR: A JOINT

and the complex challenges of meaningful reform mean that it is difficult to identify general prescriptions for effective investment contexts in the near term. Extensive literature flowing from the multilateral and development communities explores how to improve reform programs, reduce corruption, strengthen the investment climate, or improve rule of law.[26] Those are important goals, but when applied to understand the challenges of infrastructure finance and development, such studies are rarely rooted in an assessment of project outcomes, and of the wide range of factors that affect those outcomes.

The methodology for this study, detailed in Part III, takes an intermediate approach that aims to combine key strengths of the two methods that have dominated the literature so far. The study relies on detailed historical studies from twelve emerging markets—a sample selected from the more than fifty emerging markets that have had any experience with IPPs. Within that sample of countries, the project has sponsored studies that identified the full universe of IPPs in each country and then selected a smaller sample of thirty-three projects that capture the relevant factors that distinguish projects within each IPP market. The case studies examine project outcomes from two perspectives: the investor and the host government, which are often (but not always) correlated.

This paper reports the synthesis of that empirical research in two areas. First, Part IV of the paper explains the wide variation in outcomes across the twelve countries and thirty-three projects. Significant portions of the variation in outcomes reflect the work of factors that are structural in nature and largely beyond the capacity of individual stakeholders to adjust easily; they relate to the institutional characteristics of the host country and its electricity sector. Most of the stress on projects originates in these factors, but the actual project outcomes often depend on a secondary group of factors that relate to the design, structure and management of particular projects.

Project stakeholders have adopted a range of solutions designed to sustain the financial and political viability of their assets. Most of the industry literature has focused on one group of tools—referred to as "risk engineering" in this paper—that are heavily financial and legal in nature. These tools aim to bolster property rights by distilling risk into manageable parcels that can be priced, allocated, and litigated with some certainty. This study finds that such measures, while necessary, are rarely sufficient for developers' property rights in their investment to be secure. "Risk engineering" depends critically upon strong public institutions that rarely exist in these countries; when the elements of

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PED/PEG/OEU REVIEW OF THE WORLD BANK GROUP'S ASSISTANCE IN THE 1990'S (July 21, 2003), at 39 [hereinafter WORLD BANK, PRIVATE SECTOR DEVELOPMENT IN THE ELECTRIC POWER SECTOR].

[26] A detailed review of the World Bank Group's experience in fostering private sector development in the electric power sector offered the following recommendations for improving the sustainability of IPP programs: improving transmission and distribution reforms, demanding realistic demand-supply projections, balancing investment over the electricity supply chain, making a reasonable action plan for reform progress, and recognizing the limits of market forces to meet electricity investment needs when designing power sector reform. WORLD BANK, PRIVATE SECTOR DEVELOPMENT IN THE ELECTRIC POWER SECTOR, *supra* note 25, at 44.

risk engineering come under severe stress they often falter, which is illustrated by (for example) the number of contracts that have either failed or been renegotiated. Nonetheless, the failure of risk engineering does not necessarily imply the failure of the project. A second group of tools—referred to as "strategic management" in this paper—anticipate key vulnerabilities and aim to reduce the likelihood that potential risks become actual problems. These are decisions by key stakeholders within government or among project investors regarding how to select, structure, and manage an investment in a long-lived asset. While this category of mechanisms has been proposed in the literature on foreign investment,[27] it remains only lightly populated. Thus, one contribution of this paper will be to offer a range of strategic responses that have seen some success in the IPP experience.

The second goal, addressed in Part V, is to build upon this analysis of the past and suggest implications for the future IPP market, as well as particular implications for host governments and investors. The large number of IPPs in the 1990s reflected a range of factors, including: first, an excessive estimate by government officials of growth in power demand, second, the belief by host governments that private (notably foreign) investment was essential due to inadequacies in local technology and capital markets, and third, an irrational exuberance by investors that project risks in developing countries could be managed through detailed contracting. The new IPP market is likely to be smaller in size and dominated by firms that have developed special political assets and management techniques that allow them to operate in uncertain (and, for many western firms, unfamiliar) electric power markets. Especially as national capital markets have become more able to finance additional infrastructure, the comparative advantage of classic foreign IPPs over such local firms has eroded. In particular, the study observes the rising prominence of "dual firms"—that is, companies that are able to combine the political assets needed to operate a project where institutions are weak and politicized along with modern management and cost accounting—in the IPP landscape and in the electric power sector generally.[28] Nonetheless, the niche for "classic" IPPs will remain in countries unable to meet their investment needs solely from these dual firms. Thus, the paper offers a series of lessons for both host governments and for investors that aim to carry forward key insights from the successful projects of the last round of investment.

II. THE 1990S MARKET FOR INDEPENDENT POWER PROJECTS.

A. The Perfect Storm? Risks and Strategies in Electric Power Investment.

IPPs in the 1990s were undertaken in circumstances saturated with risk. The investments generated revenue in currencies that were unstable and often not freely convertible. Government finances were often in disarray and retail tariffs for electricity

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[27] Theodore H. Moran, *The Changing Nature of Political Risk*, *in* MANAGING INTERNATIONAL POLITICAL RISK 7, 11 (Theodore H. Moran ed., 1998).

[28] The idea of the "dual firm" was first proposed in an earlier PESD study on the experience of electricity reforms in five developing countries. *See* VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12.

often did not cover costs, which meant that government-controlled utilities that would buy bulk power from IPPs were not themselves solvent.[29] Governments sought IPPs at a time when they were often changing the rules that governed their electricity sectors, which introduced regulatory risk. Factor markets, including fuel, labor, and other raw inputs, usually operated in opaque ways that were poorly understood by foreign investors. Corruption was rampant in many countries that welcomed private power investment. And, IPPs often became political targets because they were on the forefront of the movements to introduce private ownership and full cost pricing for a critical and politically salient good—electricity.

In such circumstances, investors and their lenders nonetheless built projects in settings where they thought it possible to manage these risks. Mindful of the need to create a context that would allow for private investment, from the late 1980s through the 1990s host countries and project developers simultaneously followed two tracks of reform and innovation. First, most developing countries implemented broad economic reform programs (often under the guidance of the multilateral lending agencies) that were intended to establish the institutional foundation for market economies with strong rule of law. These efforts were animated by a growing body of academic work that had analyzed the institutional underpinnings of market economies, such as secure private property rights, and offered guidance for market reformers.[30] Across countries that are today known as "emerging economies," reformers focused on creating an institutional setting that included new democratic institutions with separation of powers, special foreign investment laws and investment treaties that provided protection for foreign investors, measures to reduce corruption and streamline the bureaucracy, and legal reforms that bolstered the independence of the judiciary, among others.

Second, reformers also implemented often dramatic changes in the electricity sector itself. Over the last fifteen years essentially every major developing country has undertaken some reform of its electric power system.[31] These reforms generally have aspired to the model of power sector reform adopted in Chile and in England & Wales—successful market reforms that helped to write a "textbook" for power sector reform. The textbook envisioned unbundling state utilities into separate generation, transmission,

[29] A thorough examination of the challenges of state-owned firms is included in the World Bank study, BUREAUCRATS IN BUSINESS: THE ECONOMICS AND POLITICS OF GOVERNMENT OWNERSHIP (1995).

[30] This body of thought is often traced to the pioneering work by Douglass North which focused attention on the role of institutions in economic growth. *See* DOUGLASS C. NORTH, INSTITUTIONS, INSTITUTIONAL CHANGE AND ECONOMIC PERFORMANCE (1990). Subsequent work applied these insights into the unique challenges of infrastructure investment, proposing specific institutional arrangements that allow a country to credibly commit to long term investors. *See* Levy, Brian and Pablo T. Spiller, *The Institutional Foundations of Regulatory Commitment: A Comparative Analysis of Telecommunications Regulation*, 10 J. OF L. ECON. & ORG. 201 (1994).

[31] For broad reviews of the pace and scope of reform, *see, e.g.,* R.W. Bacon and J. Besant-Jones, *Global Electric Power Reform, Privatization and Liberalization of the Electric Power Industry in Developing Countries*, 26 Annual Rev. Energy Environ. (2001); GLOBAL ENERGY SECTOR REFORM IN DEVELOPING COUNTRIES: A SCORECARD, Joint UNDP/World Bank Energy Sector Management Assistance Programme (July 1999).

distribution and marketing companies, followed by privatization. It also called for exposing generation to market competition while establishing independent professional regulators to oversee the natural monopolies of transmission and distribution.[32] In practice very few countries have actually implemented such radical power sector reforms because they have learned that the task is politically and institutionally difficult. Most countries embraced these ideas when facing the need for new investment to provide the power for rapidly growing economies. Thus, most market reforms gave particular attention to provisions, notably for IPPs, that would increase the nation's generation capacity.[33]

These two tracks—broad market-oriented reforms, and specific electricity market reforms—were usually animated by the desire to create a general institutional environment that would be attractive to private investment. Aside from these general reforms, both governments and project developers created a host of project-specific innovations that were designed to identify, allocate and mitigate the (considerable) risks that remained as the institutional environment remained in flux. Indeed, the broader reforms often magnified risk to particular investors because reforms driving the transition from state- to market-controlled economies, by nature, weaken and fragment the ability of governments to assure outcomes. The inability of host governments to make credible long-term commitments and the persistent fear of investors about the obsolescing bargain suggested a solution: the government's hands must be bound as tightly as possible with respect to a potential investment. In fact, this was explicitly called for in early explorations of long-term investment where government credibility is lacking.[34]

Historically, this was not a problem for law, but rather for shrewd business strategy—investors with long-lived assets in developing countries relied on bargaining power that derived from the continued dependence of the host country on that particular investor. For example, in seeking to protect their investment in the El Teniente copper mine in Chile, a US investor maximized the technical complexity of mining operations and signed a number of long term contracts with prominent foreign business interests, which transformed the strategic situation from one where the lone investor was facing off against the Chilean government to one that bound Chile's reputation to its behavior toward a diverse array of international business interests.[35] For decades, IBM dealt freely in the developing world, protected by a decisive lead in technological sophistication that

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[32] The ideas for standard market reforms in the electricity sector are long-standing. For an overview and discussion of this "textbook" reform, *see* DAVID NEWBURY, PRIVATIZATION, RESTRUCTURING AND REGULATION OF NETWORK UTILITIES (2000); JOSKOW, PAUL L. AND RICHARD SCHMALENSEE, MARKETS FOR POWER: AN ANALYSIS OF ELECTRICAL UTILITY DEREGULATION (1983). Most developing countries have found it difficult to implement the strictures of the standard textbook model. (Many in the industrialized world have also stumbled—spectacularly so in California.)

[33] VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12, at [page].

[34] Levy & Spiller, *supra* note 30, at 202.

[35] James K. Sebenius, *A 3-D View of Negotiation Theory and Practice*, Harvard Business School, at 18–20 (unpublished working paper, on file with author).

no other company could offer. As this advantage eroded over time, so did the security of IBM's property rights in its developing country assets.[36]

In contrast, investors in infrastructure, including power plants, thought that they lacked such self-help strategies.[37] Rather, as the infrastructure investment boom of the 1990s gained speed, so too did the construction of an *ad hoc* system of institutions and practices designed to protect property rights in settings where bargaining leverage is likely to erode.[38] In the context of IPP investment, most efforts to manage project risks started with long-term power purchase agreements ("PPAs")—the contracts that were signed between investors and the utility "offtaker" that buys the power.[39] As investors sought to insulate their projects from the vagaries of government decision-making and unexpected changes in circumstance, PPAs and related security mechanisms became ever more elaborate. Where the offtaker was a state owned utility, a sovereign guarantee was often required to support the utility's typically poor credit rating. Project documentation usually shifted legal and regulatory risk to the government, such as through change-in-law provisions that indemnified investors for losses stemming from adverse legal or regulatory changes. In addition to allocating market risk to the offtaker by specifying price formulas and minimum purchase amounts (a common practice even in industrialized countries), the contractual framework for a project often included a host of elements designed to increase enforceability, such as international arbitration, political risk insurance, and the involvement of prominent partners (notably foreign export credit agencies or multilateral lending institutions) as a deterrent to political expropriation by the host government.[40] The project financing vehicle itself limited lenders' recourse to the assets of the project itself, which meant that banks were particularly active in seeking stringent and specific loan agreements.[41] Table 1, below, presents a distilled list of primary project risks and the tools generally used to allocate them.

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[36] Louis T. Wells, Jr., *The New International Property Rights: Can the Foreign Investor Rely on Them?*, *in* INTERNATIONAL POLITICAL RISK MANAGEMENT: LOOKING TO THE FUTURE (THEODORE H. MORAN AND GERALD T. WEST, EDS., 2005) at 87, 88.

[37] Moran, *Risk in Infrastructure Investment*, supra note 15, at 10 ("Private infrastructure investors find themselves in the contemporary period without many of the tools that other kinds of investors have been able to use to lesson their vulnerability"); Wells, *The New International Property Rights*, *supra* note 18, at 89 ("In the case of infrastructure, foreigner [sic] investors usually brought no unique technology or access to markets … Without external protection, direct investors in these industries would have to be very brave, or perhaps ignorant, to enter these industries, where they would have little bargaining power once their capital was committed.").

[38] This *ad hoc* system has been referred to as the "new international property rights." Wells, *The New International Property Rights*, *supra* note 18, at 89.

[39] Reliance on a long-term power purchase agreement is not unique to developing countries. Most of the early IPPs in the United States relied on similar arrangements until the market was mature enough to support investment in merchant or other less secure models.

[40] *See generally*, Wells, *supra* note 18; *and see also* Allison Fine, *Dealing away risk in foreign infrastructure investment*, 9 J. OF STRUCT. & PROJ. FIN. 53 (2003) (finding that the extent to which investors and governments relied on contractual and other "project-specific" safeguards in telecommunications investment, depends critically on perceived institutional weakness).

[41] Restrictive loan covenants common to all lending tend to be stricter in project finance deals by themselves. Mansoor Dailiami and Robert Hauswald, The Emerging Project Bond Market: Covenant

TABLE 1: STANDARD RISK ALLOCATION IN INDEPENDENT POWER PROJECTS[42]

Construction Risks (*Contractor is often also an equity holder*)	
Cost Overruns	Allocated to contractor via fixed price turnkey EPC contracts.
Underperformance	Allocated to contractor with performance guarantees.
Operating Risks (*Plant operator is often also an equity holder*)	
Cost Overruns	Allocated to operator via Operation and Management contract.
Underperformance	Allocated to operator via Operation and Management contract.
Fuel Risks (*Fuel supplier occasionally holds equity or develops a project to sell fuel*)	
Fuel Supply	Allocated to fuel supplier with delivery guarantee ("ship-or-pay")
Fuel Price	Allocated to offtaker via indexed pass-through provision for fuel purchases.
Market Risks	
Offtake/Demand	Allocated to offtaker via long term PPAs specifying price and quantity
Currency Risk	Allocated to offtaker via denominating or indexing payments to hard currency.
Political Risks	
Regulatory Risks	Allocated to government via change-in-law provisions in project documentation.
Legal Risks	Reduced by providing for offshore arbitration to avoid domestic courts.
Contract Performance	Bolstered by sovereign guarantees, investment treaties and other legal constraints.

The emphasis on contractual risk allocation had important consequences. First, it focused attention on contracts rather than fundamental reforms. Governments learned that to attract IPP investment, actually reforming the electricity sector in a way that reduced risk was not necessary. Rather, all they needed to offer was the right package of contract terms.[43] Investors in many cases allowed the economic aspects of selling electricity to fade to the background as they focused on managing political and regulatory risk. Thus, IPP investment often concentrated in unreformed systems in which investors could deal with single state-owned offtakers—even when otherwise troublesome characteristics, such as patronage and market concentration persisted—in part because

Provisions and Credit Spreads, World Bank Policy Research Working Paper 3095 (July 2003), at 10. In developing countries these requirements are even more expansive, for example, often containing "institutional environmental provisions" that trigger redemption or take-over rights when there is a change in the underlying regulatory or legal environment. *Id.* at 9.

[42] For a more complete discussion, *see, e.g.,* John G. Mauel, *Common Contractual Risk Alocations in International Power Projects*, 1996 COLUM. BUS. L. REV. 37, 42 (1996).

[43] *See, e.g.,* Suman Babbar and John Schuster, *Power Project Finance: Experience in Developing Countries*, RMC Discussion Paper Series, No. 119, The World Bank (1998), at 10 ("As long as countries enable private project sponsors to sell power under long-term PPAs, countries do not have to make additional regulatory and market reforms to reduce the dominance of state-owned enterprises"); United States Agency for International Development, *Analysis of the Relationship Between Improved Energy Sector Governance and the Attraction of Foreign Direct Investment*, January 30, 2002 (finding that levels of greenfield investment in generation, distinct from other forms of power investment, demonstrated little correlation to improvements in electricity sector governance) [hereinafter USAID, *Governance and FDI*]; DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 85 ("Generation projects … continued to attract private investment even during the difficult financing period over the past 5 years, when the proper security package, guarantees, insurance, and PPA and tariff terms were offered.").

investors welcomed a context in which they needed to work with a limited number of players and could seek special arrangements for first-of-a-kind deals.[44]

Second, the reliance on contracts focused attention on contract stability as the indicator of host government credibility. The thesis of the obsolescing bargain primed analysts to assume that even small changes in deals would necessarily disfavor the investor and were evidence that attempts of expropriation were at work.[45] In this account, the failures of the first round of investment would call for better contracts. In reality, such a blanket condemnation is premature, for the fundamental characteristics of investment in public utilities (including IPPs) introduce many uncertainties and stresses on contracts that are not solely the work of expropriation. Across the IPP experience, many instances of renegotiation are of mutual benefit, by making a project more competitive, by clarifying contract terms, or by otherwise making the investment more sustainable for both parties.

The array of financial and contractual mechanisms discussed here enabled an unprecedented surge in investment during the 1990s. As this investment dwindled again towards the end of the decade in the midst of economic turmoil and growing investor cynicism, doubts began to cluster around the failures of this *ad hoc* regime of property rights.

B. <u>The First Round of IPP Investment</u>.

Private investment in greenfield power generation projects in developing countries was a booming market in the 1990s. The total value of IPP deals closed in 1996 alone was almost $17 billion.[46] While facilitated by the institutional reforms and contractual innovations discussed above, the supply of capital and demand for investment in this market was primarily fueled by three interacting trends. The first was increasing demand from developing countries as they reformed their electric power sectors in response to electricity or financial crises. Second, key changes in lending policies from major multilateral banks shaped government's emphasis on private investment by restricting access to concessionary loans unless coupled with complementary moves to

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[44] For discussion of the advantages and disadvantages of the single-buyer model for electricity procurement, *see* Lazslo Lovei, *The Single Buyer Model: A Dangerous Path toward Competitive Electricity Markets*, Public Policy for the Private Sector Note 225 (The World Bank, 2000); IOANNIS N. KESSIDES, REFORMING INFRASTRUCTURE: PRIVATIZATION, REGULATION, AND COMPETITION 148–153 (The World Bank, 2004).

[45] This emphasis is not limited to academic analysis, but is reflected in behavior by project sponsors and lenders. *See, e.g.*, Wigmore, Gary S. and Susan E. Turner, *The Disappearing PPA: Moving to Merchant Power in Asia*, 19 J. OF ENERGY & NAT'L RES. L. 72, 73 (2001) ("[A] state owned utility's failure to honour contract terms tends to erode investor and lender confidence in a host nation's commitment to the rule of law, with resultant investor caution and higher cost of funds to be expected in the future"); Van Mejia, *The Philippines Re-Energizes: Privatization of the National Power Corporation and the Red Flag of Political Risk*, 16 COLUM. J. ASIAN L. 355, 363 (2003)(characterizing the 2001 review of IPP contracts in the Philippines "nothing more than an attempt to back out of contracts").

[46] Data from the World Bank PPI Database, available at http://ppi.worldbank.org.

reform and privatize infrastructure. From 1990 until 1996, the World Bank Group had a "no-lend" policy (officially promulgated in a 1993 paper) for the power sector unless accompanied by substantial reforms intended to commercialize and corporatize the electricity sector, and to introduce independent regulation.[47] Third, massive liquidity and tight domestic returns in US and European utilities markets drove investors to seek higher returns in new markets abroad.[48]

The first steps in these new markets were cautious, yet momentum grew quickly. Figure 1 (next page) illustrates the rapid growth of IPP investment during the boom years of 1992-1997. While a body of theoretical and empirical work guided the architects of these early PPI schemes, careful planning often gave way to frenzy during the IPP boom years.[49] Independent power producers in developing countries were a hot commodity in the 1990s; fueled by rumors of returns of up to 35%, investors competed for market share in the new and lucrative market. Dealmakers were compensated on the value of closed deals, irrespective of the long-term performance of the project.[50] Companies sent employees abroad with new passports and fistfuls of cash with orders to buy into the IPP market. In this environment, actual practice drifted from the deeper assumptions and analysis of risk discussed above, particularly once the pioneers had blazed a trail that was easier for others to follow.

As illustrated in Figure 1, troubles began to appear in 1997 with the Asian financial crisis. By the end of the decade, the market for greenfield IPPs had collapsed in both quantitative and qualitative terms.[51] The Asian financial crisis propagated throughout the developing world—Russia in 1998, Brazil in 1999, Argentina in 2001—and projects began to unravel and new development stalled. Private investment in IPPs sank to $6 billion dollars in 2001.[52] China, India and Argentina—countries, among many others, that had been prized attractions—saw investors flee in droves. Spectacular failures, such as the Dabhol project in India, the Hub project in Pakistan, and the entire

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[47] World Bank, *Private Sector Development in the Electric Power Sector: A Joint OED/OEG/OEU Review of the World Bank Group's Assistance in the 1990s*, Report No. 26427 (2003), at 2 [hereinafter World Bank, *Private Sector Review*].

[48] *See, e.g.,* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 15, Figure 2-10 and associated text.

[49] Investors with experience managing projects in developing markets comment on this regularly. Additionally, there is increasing recognition of this factor in relevant literature. *See, e.g.*, DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 76 ("During boom markets, investors have often pursued market share while overlooking more prudent risk and return analysis").

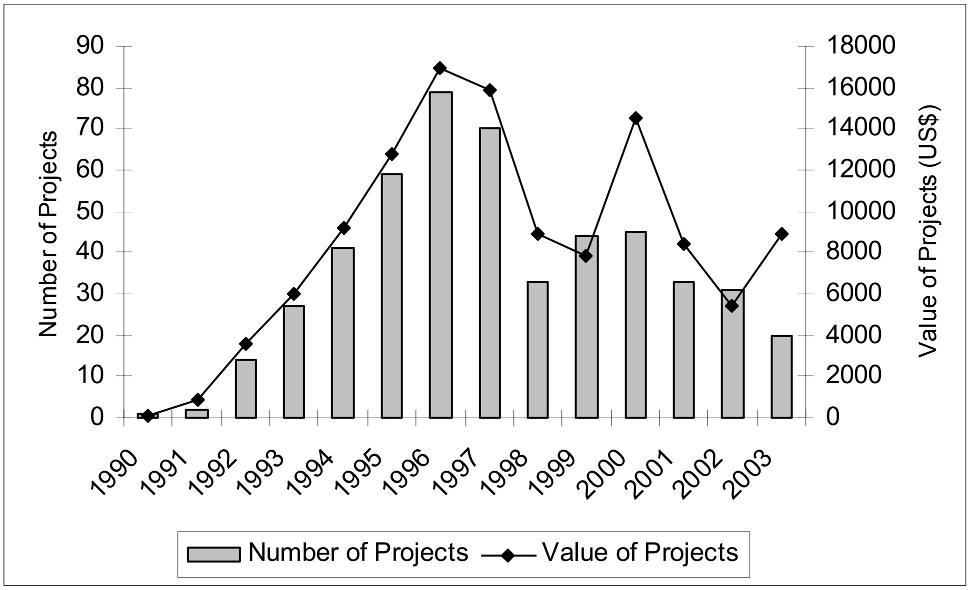
[50] This common refrain among industry participants is also commented on in Louis T. Wells, *Private Foreign Investment in Infrastructure: Managing Non-Commercial Risk*, paper presented at "Private Infrastructure for Development: Confronting Political and Regulatory Risks, Sept. 8-10, 1999, Rome, Italy, at 11.

[51] The 2003 increase of private infrastructure investment in dollar terms seen in Figure 1 reflects primarily the financial closing of a few massive deals in Southeast Asia. *See* Ada Karina Izaguirre, *Private Infrastructure: Activity Down by 13 Percent in 2003*, Public Policy for the Private Sector, Note No. 274 (World Bank, 2004).

[52] Data from the World Bank PPI Database, available at http://ppi.worldbank.org.

IPP sector in Indonesia, dominated the industry headlines. The docket of international commercial arbitration bodies was crowded with a growing list of claims by disgruntled investors.[53]

FIGURE 1: PRIVATE INVESTMENT IN POWER GENERATION IN DEVELOPING COUNTRIES



Source: World Bank Private Participation in Infrastructure Database, available at http://ppi.worldbank.org *(visited April 14, 2005).*

In addition to successive economic shocks in emerging markets, the decline in IPP investment coincided with a rash of corporate scandal in the United States (including the downfall of Enron, a major IPP investor)[54], the bursting of the dot-com bubble and domestic recession in the United States, and somewhat later, the attacks of September 11th and an increasingly uncertain global security environment. The same period was one of unprecedented turmoil in United States utilities markets, particularly in merchant electricity trading.[55] Across the Atlantic, European utilities weathered equally grave losses in their home market and grew cautious in their developing country adventures.[56]

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[53] The Argentine crisis of 2001–02 itself precipitated roughly 30 claims before arbitral panels. *See* Ada Karina Izaguirre, *Private Infrastructure: Activity Down by 13 Percent in 2003*, Public Policy for the Private Sector Note No. 274, at 3 (2004). For a rough glance at these claims, see the list of pending cases at the website for the World Bank's International Centre for the Settlement of Investment Disputes (ICSID), at http://worldbank.org/icsid/cases/pending.htm.

[54] *See, e.g.*, Henry A. Davis, *How Enron has affected project finance*, 8 J. STRUCT. & PROJ. FIN. 19 (2002) (discussing the collapse in infrastructure project financing in the context of the major corporate scandals of the late 1990s); *IPP sector unravels on Enron Collapse, casts cloud over entire industry*, CORPORATE FINANCING WEEK (June 10, 2002).

[55] *See* Roberto S. Simon, Private Sector Electricity, presentation at World Bank Energy Week 2005, *available at* http://www.worldbank.org/energy/energyweek2005/ (detailing massive losses to the major merchant power companies and major utilities in the United States during 2002 and 2003).

[56] DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 109.

These losses in home markets, along with strategic decisions to refocus on industrialized nations drove many of the most prominent players in the IPP market to exit.[57]

By 2002, the experience with IPPs had been highly variable. Some projects, such as Enron's Dabhol project in Maharashtra had been very visible failures, and a pall hung over the industry.[58] Yet, many projects continued with relative success. In the shadow of Dabhol, several IPPs in the Indian state of Andhra Pradesh have been generating electricity and receiving timely payments even in the face of controversy. In the heart of the Asian financial crisis of 1997, the government of Thailand and its IPP investors found ways to adjust projects that have recently entered service, with more planned. In the notoriously difficult power market in China, rife with legal uncertainty, some investors are earning acceptable returns and planning new investment. Thermal power projects in Brazil that are under severe pressure because they are much more costly than the incumbent hydro power have faced pressure to readjust their tariffs or be forced offline; yet some Brazilian IPPs have found ways to contract around these challenges. The next Part in this paper introduces a methodology for assessing this variation in outcomes, and Part IV summarizes the main factors that explain such outcomes.

III. ASSESSING THE IPP EXPERIENCE.

The central task of this paper is to explain the wide variation in outcomes across countries and across projects. This Part presents the methodology for exploring this variation—including the key factors that are analyzed and the cases that are selected for study. It gives particular attention to how the study measures "outcomes," and offers a brief review of the observed outcomes across the full sample of studied projects.

A. Case Selection (Countries and Projects).

This study seeks to identify the factors that affect the viability of IPP investments. The answer to this question may be found in the characteristics of the host country ("country factors"), in the structure and management of the projects themselves ("project factors"), or in events that are external to the particular choices by host governments and investors ("exogenous factors"), such as troubles in the home markets of Western investors. Table 2 identifies the key explanatory variables that were considered in selecting cases for study; these factors were identified in a review of the literature and preliminary surveys of experts.[59]

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[57] *Id.*; *and see also*, *Global power beats a retreat*, Power Magazine, March 1, 2000.

[58] *See, e.g., IPP sector unravels on Enron collapse, casts cloud over entire industry*, Corporate Financing Week, June 10, 2002.

[59] These variables were identified and defined through an initial literature review and in discussions with electricity sector investors and other experts. This process is reported in a working paper. *See* Victor, David G., Thomas C. Heller, Joshua C. House, Pei Yee Woo, The Experience of Independent Power Projects (IPPs) in Developing Countries: Introduction and Case Study Methods, PESD Working Paper #23 (2003), at http://pesd.stanford.edu/publications/20528/.

TABLE 2: LIST OF INDEPENDENT VARIABLES

Country Level Factors	
Macroeconomic Context	Whether substantial macroeconomic shock has disrupted the economy or currency of the host country.
Political & Social Context	The general environment for foreign investment, including the legal framework, political and social stability, and the extent of corruption.
Legal & Regulatory Framework	The status and goals of electricity reform and of efforts to attract foreign investment to the sector.
Electricity Market	The structure of the electricity market, including tariff levels, supply-demand balance, and the size of the market.
Fuel Markets	The fuel mix for generation, including countries with dominant incumbent fuels, and the markets that control the supply and price of those fuels.
Project Level Factors	
Investor Composition	The nature and experience of project developers, and the presence of local partners or multilateral/officials partners in the project.
IPP Program	Characteristics of the IPP program, including goals, relationship to sector reform, project selection, government counterparties and support, etc.
Financial Arrangements	The structuring of revenue generating activities (power sales) and the terms and cost of obtaining financing for the project.
Fuel & Technology Choice	Power plants with different fuel and technology characteristics have very different economic, financial, and social ramifications.
Operations & Management	Capacity to manage the political, regulatory and social risks involved in developing country power investment.
Exogenous Events	
Global Industry Downturn	Troubles in the home markets of investors and other reasons unrelated to developing country investment often constrained capital supply.

The study's approach to selecting particular cases for study followed standard scientific methods that call for identifying hypotheses about the factors that explain outcomes and then selecting cases for variation in those factors.[60] Case selection followed a two-stage process. First, from the full set of over fifty developing and transition countries that have had at least one IPP, the study selected a sample of twelve countries (Table 3) that displayed variation across the country-level factors. Based on initial reviews, the team selected seven countries for in-depth treatment, including field visits.[61] These countries are: Brazil, China, Egypt, India (in the states of Andhra Pradesh and Gujarat), Kenya, the Philippines, and Thailand.

[60] The core tenets of this case study methodology are set forth in GARY KING, ROBERT O. KEOHANE & SIDNEY VERBA, DESIGNING SOCIAL INQUIRY: SCIENTIFIC INFERENCE IN QUALITATIVE RESEARCH (1994).

[61] This field research included interviews with sponsors for most or all operating projects, government officials, including line ministries, regulators, and offtakers, and other industry participants. The central factor driving selection for fieldwork was the observation of substantial variation between project characteristics or outcomes *within* a country. In Mexico, Argentina, and Malaysia and Poland, observed variation in outcomes is primarily driven by country level factors and in many cases projects are substantially similar. By contrast, in Brazil, China, India and the Philippines, basic project characteristics such as the identity of investors, the regulatory regime in place, and fuel choice vary widely and have often affected outcomes. Outcomes in Thailand also seem primarily driven by country level variables; Thailand was included for in-depth study because of its central role in the Asian IPP experience and in order to examine the successful navigation of the Asian crisis. Egypt and Kenya were selected according to a similar calculus solely from within the universe of African countries with IPP experience.

TABLE 3: COUNTRY SAMPLE AND COUNTRY FACTORS

Country (# IPPs) Year of first IPP	**Economic Shock**	**Investment Climate**[62]		**Incumbent Fuel**	**Electricity Reform**	**Mode of Investment in Generation**
		Average	**Av. Dev.**			
Argentina (16+) 1992	High 2002	66.99	5.59	Nat'l Gas, Hydro	All sectors 1992	Brownfield and greenfield IPPs sell to privatized grid
Brazil (12) 1995	Medium 1999	64.08	2.03	Hydro	All sectors 1994 *New reform 2003*	Brownfield and greenfield IPPs selling to privatized grid
China (32) 1985	None	71.92	4.24	Coal	Generation 1985 *Ongoing changes*	Greenfield IPPs selling to sub-national SOE's
Egypt (3) 1998	Medium 2001	66.00	n/a	Gas, Hydro, Oil	Generation 1996	Greenfield IPPs selling to national electricity SOE
India (16) 1991	None	62.66	5.83	Coal	Generation 1991	Greenfield IPPs selling to sub-national SOE's
Kenya (4)[63] 1996	Low 2000-2003	58.70	n/a	Hydro	Generation 1996	Greenfield IPPs selling to national electricity SOE
Malaysia (13) 1993	High 1997	76.81	2.76	Nat'l Gas	Generation 1993	Greenfield IPPs selling to national electricity SOE
Mexico (16) 1995	None	70.69	1.45	Oil	Generation 1994	Greenfield IPPs selling to national electricity SOE
Philippines (45) 1988	High 1997	64.90	6.60	Oil	Generation 1988 All sectors 2001	Greenfield IPPs selling to national SOE or private utility
Poland (3) 1997	None	73.85	4.57	Coal	All sectors 1993 PPI in 1997	Greenfield IPPs selling to national electricity SOE
Thailand (7) 1997	High 1997	73.46	3.26	Nat'l Gas	Generation 1994	Greenfield IPPs selling to national electricity SOE
Turkey (9) 1994	Medium 2001	56.55	5.47	Hydro	Generation 1984	Greenfield IPPs selling to national electricity SOE

Second, from the universe of all IPPs in each of these 12 countries, the study selected a smaller set of thirty-three projects that demonstrated variation in the project-level factors.[64] For countries where the story appeared to reside entirely with country-

[62] The investment climate of a country is commonly evaluated with a dizzying array of commercial and scholarly indices, including commercial sovereign debt rating (e.g. Standard & Poor's), commercial country risk evaluation (e.g. International Country Risk Guide), or rankings developed by prominent multilateral or non-governmental entities (e.g. the Transparency International Corruption Perceptions Index, World Bank Investment Assessment). In explaining outcomes in IPP investment, these aggregate measures of country risk are of minimal value. In fact, except for the correlation between various basket indicators (such as the ICRG index) and aggregate levels of FDI inflow, there is scant evidence that presents a robust relationship between the common measures of these factors and investment outcomes (of any kind). *See, e.g.*, Witold J. Henisz and Bennet A. Zelner, *Measures of Political Risk*, mimeo, available at http://www-management.wharton.upenn.edu/henisz/ (criticizing a variety of political risk indicators for failing to explain economic or political instability, events of expropriation, or other investment outcomes); Anja Linder and Carlos Santiso, *Assessing the Predictive Power of Country Risk Ratings and Governance Indicators*, SAIS Working Paper Series, WP/02/02, available at http://www.sais-jhu.edu/workingpapers/WP-02-02b.pdf. This study comments on various specific aspects of the investment climate, such as the state of public finance or perceived levels of corruption, where appropriate, but does not address these broad measures.

[63] In Kenya, there were also three privately financed "emergency" plants (totaling 105MW) that were funded primarily via World Bank loans and signed one-year contracts to help alleviate pressure from a drought on Kenya's hydro dependent electricity sector. These projects are often referred to as "IPPs"; nonetheless, they are excluded for being distinct in size, duration of contract, financing and purpose, from other IPPs (even within Kenya).

[64] Full details of the study methodology are provided in the IPP Study Protocol, *supra* note 5. Additional information on the variables considered in country- and project-selection is provided in Annex 3 to this paper.

level or exogenous factors, the study examined only a very small number of projects (e.g., Thailand) or no individual projects at all (e.g., Argentina and Malaysia). The sample includes a range of factors particular to projects (e.g., the composition of investors) as well as variation within countries, such as when projects exist in states within a federal system of government (e.g., India), under regulatory frameworks that vary over time (e.g., Kenya, Turkey and Mexico), or when IPPs sell their power to offtakers that vary in their structure and financial solvency (e.g., Brazil). These within-country and across-time variations provide critical control cases that allow individual factors to be isolated and examined across countries.

TABLE 4: PROJECT SAMPLE AND PROJECT FACTORS[65]

Project Name	Country	Fuel	Capacity	Cost US$*	COD	Investor Mix
Termoceará	Brazil	Nat'l Gas	290MW	$100	2002	Foreign/Local
Macaé	Brazil	Nat'l Gas	928MW	$730	2001	Foreign
Norte Fluminense	Brazil	Nat'l Gas	780MW	$887	2004	Foreign
Uruguaiana	Brazil	Nat'l Gas	600MW	$350	2000	Foreign
Caña Brava	Brazil	Hydro	450MW	$426	2002	Local
Shajiao C	China	Coal	1980MW	$1,870	1996	Foreign
Meizhouwan	China	Coal	724MW	$755	2001	Foreign
Shandong Zhonghua	China	Coal	3000MW	$2,200	2003[66]	Foreign/Local
Sidi Krir	Egypt	Nat'l Gas	685MW	$418	2002	Foreign
Suez	Egypt	Nat'l Gas	683MW	$340	2003	Foreign
Port Said	Egypt	Nat'l Gas	683MW	$338	2002	Foreign
GVK Jegurupadu	India	Nat'l Gas	216MW	$261	1996	Foreign/Local
Lanco Kondapalli	India	Nat'l Gas	250MW	$285	2000	Foreign/Local
Essar Power	India	Naphtha/Gas	515MW	$514	1995	Local
CLP Paguthan	India	Naphtha/Gas	655MW	$734	1998	Foreign
PPN Power	India	Naphtha/Gas	330MW	$252	2001	Foreign/Local
ST-CMS	India	Coal (Lignite)	250MW	$320	2002	Foreign/Local
IberAfrica	Kenya	Diesel	44MW	$65	1997	Foreign
Tsavo	Kenya	Diesel	75MW	$85	2001	Foreign
Monterrey III	Mexico	Nat'l Gas	1140MW	$609	2001	Foreign
Rio Bravo II	Mexico	Nat'l Gas	568MW	$234	2002	Foreign
Merida III	Mexico	Nat'l Gas	530MW	$260	2000	Foreign
Navotas I	Phil.	Diesel	210MW	$40	1991	Foreign
Pagbilao	Phil.	Coal	700MW	$888	1996	Foreign
Quezon	Phil.	Coal	460MW	$895	2000	Foreign/Local
Casecnan	Phil.	Hydro	140MW	$495	2001	Foreign
Cavite	Phil.	Diesel	63MW	$22	1995	Foreign
ENS	Poland	Nat'l Gas	116MW	$132	2000	Foreign/Local
Elcho	Poland	Coal	720MW	$324	2003	Foreign/Local
Eastern Power	Thailand	Nat'l Gas	350MW	$250	2003	Foreign
Independent Power	Thailand	Nat'l Gas	700MW	$369	2000	Foreign/Local
Gebze, Adapazari, Izmir	Turkey	Nat'l Gas	3860MW	$2000	2002	Foreign/Local
Trakya Elektrik	Turkey	Nat'l Gas	478MW	$600	1999	Foreign/Local

* In millions of United States dollars.

The core analysis of the paper rests on this sample of twelve countries and thirty-three projects. Where appropriate information is available, experiences from other countries such as Indonesia are commented upon to extend the reach of the paper. Additionally, the process of researching each of the twelve sample countries yielded a

[65] More extensive details on each project are provided in Annex 1 and Annex 3.

[66] The brownfield units at Shandong Zhonghua were operational in 1997 and 1998.

rich body of information regarding other projects beyond those selected for individual study. Where useful (or in some cases necessary), these experiences are also referred to.

B. The IPP Experience: The Rough Guide.

The study defined "outcomes" according to the goals that investors and hosts could reasonably expect to achieve when they commit to a project. For host countries, this comprises whether the country has succeeded in attracting investments that actually led to the production of electricity, and whether the price, quantity, and other terms for such private electricity are within a band of reasonable expectations.[67] Such evaluations included an assessment of the political, economic and social sustainability of the projects. These assessments require the use of both objective data (*e.g.*, prices or payments, project costs, and technical performance) as well as subjective assessments (*e.g.*, gleaned in interviews with government officials and reactions from consumers and civil society).

For investors, the study made a similar evaluation of whether project performance compared favorably with reasonable expectations. Where financial data or reliable proxies were available, financial performance was the basic indicator. Often, however, such data are confidential or are aggregated in ways that make it difficult to examine the investor's experience with a particular country or project.[68] In these instances, the study also considered other measures, such as the stability of contracts and the nature of adjustments, the record of payments, subjective evaluations by investors, experts and officials, as well as whether private investors would pursue similar projects in the future.

On both these dimensions—country experiences and investor experiences—the yardsticks for measuring performance are reasonable goals. During the 1990s, both governments and investors often carried unrealistic expectations into new projects. For example, many governments expected the IPPs would lead to lower prices; yet existing

[67] One core problem in IPP investment is that there is no clear metric for evaluating success from the perspective of the host country. By contrast, for privatizations of distribution companies or for wholly competitive regulated generation markets the promulgation of metrics for success has been a difficult but attainable goal. For examples of such evaluations from Argentina and Chile, s*ee* Antonio Estache and Martin Rodriguez-Pardina, Light and Lightning at the End of the Public Tunnel: Reform of the Electricity Sector in the Southern Cone, Policy Research Working Paper, No. 2074 (World Bank, 1999); Antonio Estache and Martin Rodriguez-Pardina, *Regulatory Lessons from Argentina's Power Concessions*, Viewpoint Note No. 92, The World Bank Group (Sept. 1996); Pedro J.A. Ferreira, On the Efficiency of the Argentinean Electricity Wholesale Market, Seminario No. 09/02 (June 6, 2002). Distribution companies are regulated entities that offer a range of available data for evaluation. In most cases, IPPs are not regulated in any public manner, and obtaining any data on useful performance criteria such as price, efficiency, heat rate, or emissions, is extremely difficult.

[68] *See, e.g.*, Estache & Pinglo, *supra* note 23, at 13 (explaining reliance on an independent method of calculating return-on-equity, because the best measure of project returns, internal-rate-of-return, is generally unavailable); Sirtaine, et al., *supra* note 23, at 10 (discussing the problems associated with gathering and evaluating financial data on infrastructure investment across countries, including differing accounting and reporting standards, and the confidentiality of critical data). Additionally, the structure of IPPs makes the task more difficult still—because regulation for these projects is usually contained in a private contract, there is no public regulatory process that gathers and publishes financial and performance data, as in some concessions for other sectors, such as distribution companies.

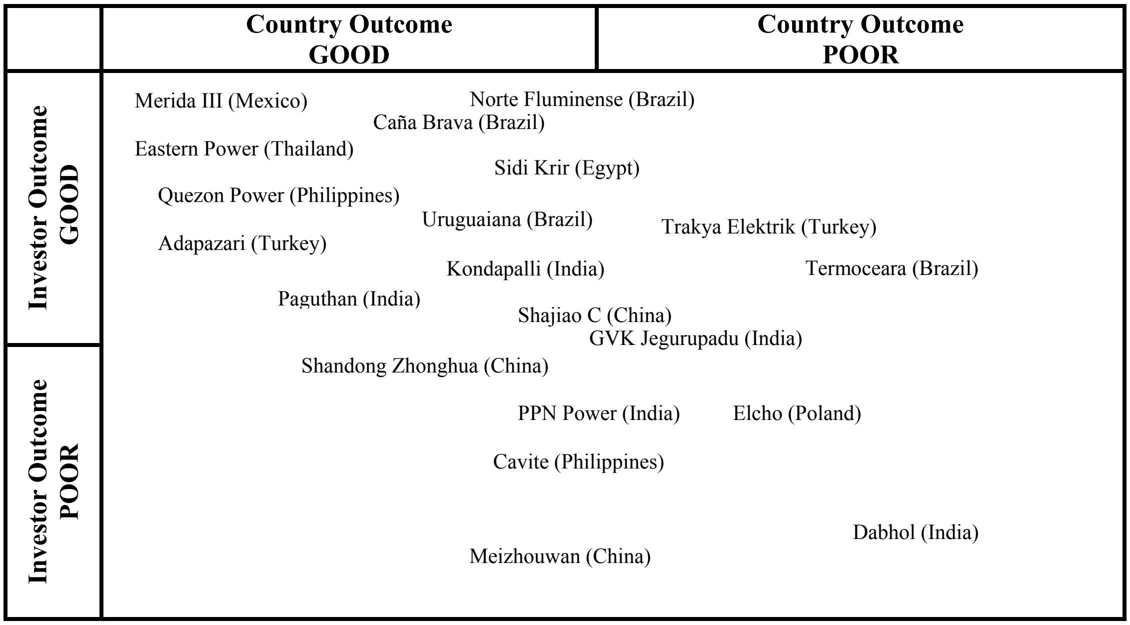
power plants, against which IPP prices were compared, were often built with soft capital and hidden subsidies that artificially reduced their posted prices. (Moreover, technologically, the electricity industry has been marked, generally, by declining costs throughout the 20th century until the 1970s, when the cost of the best plants leveled and has since increased.)[69] Thus, the bare fact that IPPs, in practice, were often more expensive than the incumbent state-built power projects cannot, without additional analysis, be taken as signaling a poor outcome. Similarly, investors often had unrealistic expectations about their ability to manage risks and inflated their expected returns; the inability of a particular plant to earn a posted return, or of a contract to hold strictly to its original terms, is not necessarily evidence of the project's failure to meet reasonable goals. The need for such subjective assessments is one reason that the study kept the sample small, which allowed for detailed case analysis.

Figure 2 sets forth a schematic representation of the two axes on which the study has assessed project outcomes. Most cases fall on the axis from northwest (positive outcomes for host and investor alike) to the southeast (poor for both). This correlation largely reflects that, when looking at individual projects, the long-term interests of the host and investor are broadly aligned.[70] Governments that squeeze IPPs (or allow IPPs to be squeezed) to produce unsustainable returns for investors generally find, along with their investors, that the IPP experience is unsatisfactory. Where the context entices investors to make additional investments, both host governments and investors tend to profit. However, the individual stories are complicated and all four cells of experience are filled with examples that populate the remainder of this report. The next few paragraphs offer a brief overview of the experiences in each country before turning to in-depth analysis in the next Part of this article.

[69] *See* David G. Victor, *Electric Power*, *in* TECHNOLOGICAL PERFORMANCE & ECONOMIC PERFORMANCE 385–415 (Benn Steil, David G. Victor & Richard R. Nelson, eds. 2002).

[70] This pattern may reflect two additional factors. First, the northeast cell is unstable for projects—it would be populated by projects that are unreasonably burdensome for the host country yet are paid according to the investors' expectations. Projects such as Enron's infamous Dabhol plant that might occupy that box appear to unravel quickly and migrate to another box, depending on the conduct and terms of the workout. Second, the southwest cell is unstable for countries—it can be populated only where the country does not mind the reputation of exploiting investors; in this sample, perhaps only China can exhibit such behavior because after the first round of IPPs the Chinese government no longer needs outside investors. However, just as it will be difficult for projects to remain in the northeast cell, even China may find it difficult to remain in this position over time.

FIGURE 2: THE TWO-DIMENSIONS OF PROJECT OUTCOMES FOR A SELECTION OF PROJECTS[71]



The IPP market in developing countries first took root in Southeast Asia. Starting in the early 1990s, the Philippines, Malaysia, and Thailand all experimented with private greenfield project development to meet new electricity needs. Each country incorporated these IPPs into largely unreformed electricity markets, relying on a single national utility to purchase the electricity from the new power plants. Across Asia, most countries employed this "single buyer" model for IPPs in which the IPP sold bulk electricity to a single state-owned utility that had responsibility for delivering the electricity to final customers.

Thailand[72] was the leader in this regard. IPPs entered Thailand via a highly competitive and transparent 1994 bidding process. The disruption of the Asian financial crisis delayed many of these projects and forced government and investors to make substantial adjustments that, in turn, have allowed most of the original IPPs to survive and eventually to prosper financially. The successful experience with IPPs in Thailand is driven mainly by factors that affected the whole country, in particular the method of solicitation, the impact of the Asian financial crisis and the management of its aftermath.

The experience in Malaysia[73] is roughly similar to that in Thailand; a 1993 solicitation led to private investment in thirteen mostly natural gas-fired IPPs. However, while most countries have seen foreign investors dominate the IPP sector, the Malaysian

[71] Because of space constraints, the sample of projects included in this figure is smaller than the full sample examined in this paper. The figure is used primarily to illustrate the trend in project outcomes for investors and for countries.

[72] Pei Yee Woo, Independent Power Producers in Thailand, PESD Working Paper No. [--] (2005), *available at* http://pesd.stanford.edu/ipps.

[73] Jeff Rector, The IPP Investment Experience in Malaysia, PESD Working Paper No. 46 (2005), *available at* http://pesd.stanford.edu/ipps.

experience has been a local affair—local investors, local capital, and fuel inputs denominated in local currency—which has made it easier to govern the projects. Notably, IPPs in Malaysia weathered the Asian financial crisis with healthy profits because currency risks and other shocks to the projects were fewer and less severe. The few projects that demonstrate poor outcomes were limited to those endeavors that were plagued by poor design or planning (such as the Bakun Hydro project[74]). While illuminating the benefits of local investment, other countries will find it difficult to replicate the Malaysian experience since most countries have pursued IPP programs in an effort to overcome limitations of solely local capital and expertise.

The Philippines[75] has had a long history with IPPs; the first contract was signed in 1988 and more than forty projects have been built in total. IPPs in the Philippines have exhibited a wide variety of characteristics from fuel choice to the composition of project sponsors and the identity of the offtaker, allowing for examination of the impact of these project factors while controlling for country level factors. Despite these variations across project characteristics, outcomes have been remarkably consistent—IPPs in the Philippines have largely earned healthy returns, even in the wake of economic crises and a highly visible renegotiation of most of the PPAs in the sector. From the country perspective, returns have been mixed. Political instability and poor sector planning have led to expensive electricity (notably from the "fast track" plants built to address a severe electricity shortage during 1992–93). The impact of the Asian financial crisis has inflated the local currency cost of private power substantially, which affects the economy a whole and has invited loud criticism of the IPPs from politicians and from civil society.

Turkey, Egypt and Kenya also employed a single-buyer model. IPPs in Turkey[76] have been developed under two very distinct regimes—an earlier "build own transfer" (BOT) scheme in which each plant negotiated its contract with the government utility individually, and a later "build own operate" (BOO) system in which PPAs were awarded through competitive bidding. A 2001 shock to the Turkish economy (which severely devalued the Turkish Lira) stressed all projects; although the original contracts have largely held in all cases, the plants that had been developed through competitive bidding found it easier to manage the consequences of the currency devaluation because these plants already had a competitive tariff structure. This experience underscores the importance of structuring projects so that they can weather unpredictable (but not unlikely) challenges—in this case a macroeconomic shock.

Egypt[77] opened its generation sector for private investment in 1998 and now buys

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[74] *Id.* at 14; Ariane Sains, *No guts, no glory: Country risk a fact of life for IPPs abroad*, Electrical World, Nov. 1, 1997 (detailing the problems that beset the Bakun project).

[75] Erik J. Woodhouse, The Philippines Electricity Market Investment Context, PESD Working Paper No. 37 (2005), *available at* http://pesd.stanford.edu/ipps.

[76] Efe Cakarel and Joshua House, IPP Investment in Turkey's Electric Power Industry, PESD Working Paper No. 32 (2005), *available at* http://pesd.stanford.edu/ipps.

[77] Anton Eberhard and Katharine Gratwick, The Egyptian IPP Experience, Managing Infrastructure Reform & Regulation, University of Cape Town (August 2005), *available at* http://gsb.uct.ac.za/mir.

electricity from three IPPs. The Egyptian IPPs are notable for their low prices (US 2.3 cents/kWh in one case, among the lowest anywhere in the world), which reflect both the highly competitive bidding that allocated the projects and the availability of subsidized natural gas from the Egyptian state gas monopoly. As in southeast Asia, the central event has been macroeconomic shock—during 2001-02, the Egyptian pound fell to almost half of its original value and the dollar-denominated IPP contracts doubled in price (in local currency terms). Despite these shocks, the contracts for these plants have held with only minor adjustments to ease some burden from the currency devaluation. Egypt has turned away from private developers for the next phase of capacity additions in the electricity sector. Nonetheless, funding appears incomplete for an additional development during 2007-2012, perhaps setting the stage for an additional round of private investment.

Kenya[78] is unique in the country sample for having an electricity sector that totals only 1200 megawatts of total installed generating capacity. Additionally, the turn towards IPPs in Kenya was undertaken in extremely difficult circumstances; for most of the 1990s, the international aid community enforced an aid embargo against the country in response to rampant corruption and political illiberalism. In this difficult environment, IPPs arrived in two waves. First, a 1995 bidding process led to contracts for two projects that followed the standard international model (a single buyer with a long-term 20-year PPA). However, the Kenyan government balked at providing sovereign guarantees for these projects, which led to delays in securing financing (and one of the projects still has not reached commercial operations a decade later). Thus, in the interim, Kenya solicited two "stop-gap" IPPs with seven-year, renewable contracts. The outcomes have been mixed; in each group of projects one investor has lost interest while the other investor has demonstrated strong interest in remaining in the Kenyan power sector.

India and China present large, complex and fragmented power systems that lead to much variation in IPP experiences.[79] China[80] is the world's largest IPP market in which foreign investors have been willing to pursue risky (arguably unsound) projects in part because their firms feel a strategic need to be "in China." In practice, investors have found it extremely difficult to enforce their contracts and have adopted a long list of strategies, from strategic partnerships to various privately ordered payment and security

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[78] Anton Eberhard and Katharine Gratwick, The Kenyan IPP Experience, Managing Infrastructure Reform & Regulation, University of Cape Town (August 2005), *available at* http://gsb.uct.ac.za/mir.

[79] India is politically organized as a federal state, and the constitution divides authority over electricity between the federal and state governments. China, while not a federal state, has power bureaus in each province; originally these were primarily administrative designations, but sector reforms in the 1990s devolved increasing authority to the local power authorities. Thus, neither China nor India has a "single buyer" in a strict sense. Rather, in each province or state these countries have single buyers—nearly always the state-owned utility (although one project examined in this paper, Essar Power, also sells to a captive steel plant).

[80] Pei Yee Woo, China's Electric Power Market: The Rise and Fall of IPPs, PESD Working Paper No. 45 (2005), *available at* http://pesd.stanford.edu/ipps; *see also*, Pei Yee Woo, Recurring Dream or Incessant Nightmare?: Foreign Direct Investment in China's Power Industry (2003)(unpublished thesis on file with PESD); Chi Zhang and Thomas C. Heller, *Reform of the Chinese Electric Power Markets: Economics and Institutions*, *in* VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12; THE PRIVATE SECTOR AND POWER GENERATION IN CHINA, WORLD BANK DISCUSSION PAPER NO. 46 (2000).

arrangements, in an effort to manage this risk. China allows for a controlled analysis of how these different investor strategies affect outcomes in the face of almost meaningless contractual enforcement, and the study has devoted substantial resources to understanding the Chinese experience. In broad terms, the experience of investors in China has been poor; however, China also benefits from substantial investment from a new class of investors who rely sparingly on contracts to manage investments. Outcomes for China have been positive in some ways, introducing new technology and helping continue investment during a fragile fiscal period in the early 1990s. China has also succeeded in reducing prices; in many countries this would signal a poor outcome because of its deterrent effect on further investment. In China, it remains to be seen whether the country will pay a price, or whether in transitioning to primarily domestic investment, the country is sufficiently insulated from a backlash in the investment community.

India[81] is the site of the most striking controversy in foreign greenfield IPPs—Enron's Dabhol project. However, the country has also hosted a series of largely successful projects, thus offering enormous variation in outcomes. The country, which is federal in structure, also demonstrates substantial variation in regulatory systems that have governed IPPs, as well as the political and economic conditions across the different Indian states. The world's largest democracy also offers a location to observe political controversy about IPP pricing and the effectiveness of efforts by hosts and investors to manage the political and social implications of private power supplies.

The Latin American and European approach to electricity reform has followed a different model than in Asia because they have implemented the most extensive reforms of the power sector. They have unbundled and privatized generation, transmission and distribution sectors—creating (except in Mexico) multiple buyers for power. All these elements of the restructured power market operate under the supervision of an independent regulator. Following Chile's successful example, in the early 1990s Argentina[82] adopted what was widely seen as an "ideal" electricity reform and IPP law—it created clear rules for investors and allowed generators to be paid both for providing capacity and for the actual power they generated. The country's 2001-02 macroeconomic crisis, and the government's decision to change the denomination of contracts from dollars to local currency, exposed investors to enormous currency risk from which none of the projects has yet recovered.

The government of Brazil[83] intended to implement a reform roughly similar to

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[81] Peter M. Lamb, The Indian Electricity Market: Country Study and Investment Context, PESD Working Paper No. [--] (2005), *available at* http://pesd.stanford.edu/ipps; *see also*, Rahul Tongia, *The Political Economy of India Power Sector Reforms*, in VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12.

[82] Erik J. Woodhouse & Alejandra Nuñez, The IPP Investment Experience in Argentina, PESD Working Paper No. 44 (2005), *available at* http://pesd.stanford.edu/ipps.

[83] Adilson de Oliveira, Erik J. Woodhouse, Luciano Losekann, and Felipe V.S. Araujo, The IPP Experience in the Brazilian Electricity Market, PESD Working Paper No. [--] (2005), *available at*

that in Argentina, but political and other problems stalled the effort and led to a power market that was only partially reformed and that created special risks for some IPPs. The Brazilian power sector is dominated by hydroelectricity, which made investment particularly difficult for new investment in gas-fired power plants because gas pricing arrangements were not aligned with the needs of the power sector. Additionally, Brazil's constantly changing market rules multiplied the uncertainties for investors. Some projects have managed these risks effectively, and the Brazilian case reveals a wide variation across outcomes within the country.

Mexico[84] followed the Asian model and kept a single buyer (the state-owned utility Comisión Federal de Electricidad, or "CFE") that contracted with all IPPs. The government adopted three distinct arrangements for IPPs by adjusting the terms for foreign participation and (notably) the arrangements for fuel contracts while other factors remained constant. The other crucial feature of the Mexican system is a payment scheme known by its Spanish acronym, "Pidiregas," that pays investors according to dollar-denominated contracts while absorbing currency risks and other liabilities in the federal government's balance sheet. The result is that IPPs, until recently, have seen Mexico as a reliable host country; along with Egypt and Thailand, the Mexican case reveals the best experiences for investors and hosts. Yet, the long-term sustainability of the program is doubtful as liabilities mount. Mexico is also a valuable control case for the effects of economic shock; during the IPP program the country has not suffered any substantial economic distress.

In Eastern Europe, including Poland, electricity reform has included the privatization of distribution and generation—reforms driven, in part, by plans for EU accession. Poland's[85] power system is dominated by coal, but a new gas pipeline from Russia built in the 1990s made gas-based power generation possible on a large scale. Environmental considerations along with an interest in fuel diversity animated the country's interest in natural gas; politically powerful groups in the coal industry resisted this diversification in fuels. Poland's IPPs include both gas- and coal-fired units, which allows for a comparison with other countries that have sought to introduce new fuels into the generation sector via IPPs. The Polish case also illustrates the tension between extensive (and sustained) power market reforms and the arrangements that are necessary to attract IPPs. While reform efforts continue to aim at a liberalized market that will satisfy EU regulators, the process has been traumatic for both investors and government. Several attempts to cancel long-term PPAs have met with resistance from investors, yet complementary attempts to fashion a plan to provide compensation have been overruled by EU regulators. Caught in this drama, investor outcomes for the two projects examined in the study appear differentiated primarily by time; while one project operated for

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http://pesd.stanford.edu/ipps. *See also*, Adilson de Oliveira, *The Political Economy of the Brazilian Power Industry Reform*, in VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12.

[84] Alejandra Nuñez, Private Power Production in Mexico: A Country Study, PESD Working Paper No. 37 (2005), *available at* http://pesd.stanford.edu/ipps.

[85] Joshua C. House, The Polish Electricity Market Investment Context, PESD Working Paper No. 31 (2005), *available at* http://pesd.stanford.edu/ipps.

several years before the debate over PPA cancellation erupted, another project reached commercial operations just in time to join the debate over its demise.

IV. EXPLAINING OUTCOMES IN IPP INVESTMENT.

The existing literature on the IPP experience has explored, individually, many of the factors that partly explain the outcomes for IPP investors and host countries. In practice, however, it has been difficult to clarify the relationship of these factors to actual outcomes for projects. The sources of stress for project do not occur in isolation, and the extent to which they propagate to a project's bottom line or to the impression of a country as a "risky" place to do business depends on a complex array of intervening factors.[86]

This Part aims to present a synthesis of the factors that explain IPP outcomes. It examines those factors at two levels.[87] First are structural sources of risk that arise mainly through the economic context of the host country and its electricity market. These structural factors largely determine the risks to which a project will be exposed and thus often appear to be the primary determinants of outcomes. These risks are not easily controlled by either party (*e.g.* the path of electricity reform), or not easily changed (*e.g.* enforcing a fiscal policy that will mitigate the impact of external financial contagion), and not easily evaluated by investors (*e.g.* the risk of political or social instability).[88] Variation in these key structural variables—such as macroeconomic shock, power sector reform and corruption—nonetheless do not determine the actual outcomes for individual projects. Second, the study examines a wide array of particular project-level factors that largely determine how the structural context affects the outcomes for individual projects. In brief, the country factors determine, broadly, the stresses on IPPs and their contracts but the project-level factors largely determine the final outcomes.

Additionally, there two types of project-level factors. The first type—referred to as "risk engineering" here—has been the subject of most project-level analysis. This category includes the wide array of sophisticated tools that investors and project operators have used to engineer the level and allocation of risk in a project. These include risk pricing systems and contracts that are intended to bind the hands of the host

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[86] Gerald T. West, *Managing project political risk: The role of investment insurance*, 2 J. PROJ. FIN. 5, 6 (1996) ("It is important to note that risk is not a quality inherent in a country, a government, or an environment; risk is a property associated with an individual investors and prospective investment."); Witold J. Henisz & Bennet A. Zelner, *Political Risk Management: A Strategic Perspective*, *in* INTERNATIONAL POLITICAL RISK MANAGEMENT: THE BRAVE NEW WORLD 154, 156 (Theodore H. Moran, ed., 2004).

[87] The relationship between institutions, transactions, and risk has been explored in literature from a variety of disciplines. The approach utilized here draws in particular on OLIVER E. WILLIAMSON, *The Institutions and Governance of Economic Development and Reform*, *in* THE MECHANISMS OF GOVERNANCE 322, 326-328 (1996); *and also* ROGER MILLER & DONALD LESSARD, THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE (2002).

[88] Claire A. Hill, *How Investors React to Political Risk*, 8 Duke J. Comp. & Int'l L. 283, 284–86 (1998) (noting a pattern of risk premia in foreign direct investment declining steadily to low points just prior to major crises that jolt them back up).

government and to allocate risks precisely.[89] Such measures, intended to bolster the investor's property rights in long-lived assets, are in practice often necessary, but rarely sufficient for secure those rights. When projects face extreme stress the "risk engineering" approaches often fail. In some cases, they exacerbate the failure because the tools of risk engineering—the pricing of risk, maximizing leverage, multiplying the size of lending syndicates, and demanding ever more strict limits on government policy—magnify some of the stresses on projects and reduce the ability of hosts and investors to maneuver. In addition to risk engineering, there is a second category of tools called "strategic management." This includes the efforts of project architects—including government officials as well as investors—to anticipate key points of vulnerability, to take steps that reduce the likelihood that particular risks will materialize, and to align incentives in a way that allows projects to withstand stress this is generally inevitable. The study suggests that this "strategic management" is the key to making projects sustainable and also offers the clearest opportunities for operators and hosts to improve the performance of IPPs.

A. Countries: The Structural Context for Investment.

The "investment climate" of a country is commonly evaluated with a dizzying array of commercial and scholarly indices.[90] These indices are often correlated with investment in myriad ways, including the cost of private capital (e.g., risk premia)[91] and the structure of investment vehicles.[92] Yet, in explaining outcomes in IPP investment,

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[89] The tools that comprise this approach to risk management have been described in a variety of ways. *See* Theodore H. Moran, *The Changing Nature of Political Risk*, *in* MANAGING INTERNATIONAL POLITICAL RISK 7, 11 (Theodore H. Moran ed., 1998) (noting the prevalence of "legal and financial" risk management that seeks to price risk appropriately and lock in absolute terms, as opposed to strategic management that seeks to anticipate and reduce risks); Donald Lessard & Roger Miller, *Mapping and Facing the Landscape of Risks*, *in* THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE (ROGER MILLER & DONALD LESSARD, EDS., 2002) 76–92, at 85–86 (distinguishing between "decisioneering" approaches to risk management, which attempt to calibrate discounted cash flows to predictions about future risk, and "managerial" approaches to risk management, which attempt to "match risks with strategies" in order to "influence outcomes"); *See also,* Roger Miller & Xavier Olleros, *Project Shaping as Competitive Advantage*, *in* ROGER MILLER & DONALD LESSARD, THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE 93–112 (2002) (arguing that large engineering projects, including power plants, that are successful are not "selected"—i.e. dependent wholly on external variables—but rather are "shaped"—a process that entails constant adaptation, innovation and adjustment by key managers who understand and react effectively to evolving risks).

[90] More prominent examples include commercial sovereign debt rating (e.g. Standard & Poor's), commercial country risk evaluation (e.g. International Country Risk Guide), or rankings developed by prominent multilateral or non-governmental entities (e.g. the Transparency International Corruption Perceptions Index, World Bank Investment Assessment).

[91] *See* Benjamin C. Esty and William L. Megginson, *Creditor Rights Enforcement and Debt Ownership Structure: Evidence from the Global Syndicated Loan Market* (finding that a 10 point increase in the ICRG composite risk index increases project bond credit spreads by 150 basis points).

[92] *See id*. (finding that banks react to developing country risk by organizing larger and more diverse lending syndicates); Beata K. Smarzynska and Shang-Jin Wei, *Corruption and Composition of Foreign Direct Invesmtent: Firm-Level Evidence* (The World Bank) (finding that increasing levels of corruption make foreign investors less likely to engage a local partner).

these aggregate measures of country risk are of minimal value. As some analysts have noted,[93] broad indicators of "investment climate" rarely explain particulars—especially for large investments (such as IPPs) for which special rules and provisions often apply. Thus in looking to country risk factors this study looks beyond simple indicators and identifies five factors that are often cited as determinants of a country's performance with private investment generally and in the power sector specifically. They include: the presence of macroeconomic shock (Part IV.A.1), corruption and other political risks (Part IV.A.2), the cost structure in the host electricity market (Part IV.A.3), the legal and regulatory framework for private investment in the power sector (Part IV.A.4), and the organization of fuel markets (Part IV.A.5). These five correspond with the country factors identified through the literature review that informed our selection of cases, summarized in Table 2.

1. *Macroeconomic Shock.*

The most prominent single explanation for the collapse of the IPP market in the late 1990s is a succession of macroeconomic crises.[94] These include the Asian financial crisis, devaluation of local currencies in Turkey, Egypt and Brazil, and the meltdown of the Argentine economy in 2001-02. In all, six of twelve sample countries in this study suffered a substantial macroeconomic shock; all six saw severe stress imposed on IPPs as a result of the macroeconomic shock. Reducing exposure to macroeconomic instability, particularly to currency risk, remains the crucial hurdle to continued development.

Nonetheless, macroeconomic shocks alone do not explain the *outcomes* for IPPs. Rather, a range of country- and project-specific factors determine how the macroeconomic shock propagates to the level of individual projects. These factors begin with government policy on the allocation of macroeconomic risks, and include the severity of the crisis and its effect on currency values, the exposure to currency fluctuations via payments for fuel and debt service as well as revenues from electricity sales, and the effects of the crisis on the financial solvency of the entity that purchases the power from IPPs.[95] These factors, and the experiences of the six countries that faced macroeconomic shock (along with Indonesia, which is included because of its central

[93] This critique is not new. In fact, except for the correlation between various basket indicators (such as the ICRG index) and aggregate levels of FDI inflow, there is scant evidence that presents a robust relationship between the common measures of these factors and investment outcomes (of any kind). *See, e.g.*, Witold J. Henisz and Bennet A. Zelner, *Measures of Political Risk*, mimeo, available at http://www-management.wharton.upenn.edu/henisz/ (criticizing a variety of political risk indicators for failing to explain economic or political instability, events of expropriation, or other investment outcomes).

[94] Gray, R. David and John Schuster, The East Asian Financial Crisis—Fallout for Private Power Projects, Viewpoint Note No. 146, The World Bank (1998).

[95] *See* R. David Gray and John Schuster, *The East Asian Financial Crisis-Fallout for Private Power Projects*, Viewpoint, Note No. 146 (The World Bank, August 1998); Thierry Lefevre and Jessie L. Todoc, *IPPs in APEC Economies: Issues and Trends*, Paper Presented at "The Clean and Efficient Use of Fossil Energy for Power Generation in Thailand," The Joint Eighth APEC Clean Fossil Energy Technical Seminar and Seventh APEC Coal Flow Seminar, APEC Clean Fossil Energy Experts' Group, Bangkok, Thailand, October 30-November 3 (2000).

position in the IPP experience following the Asian financial crisis), are summarized in Table 5.

TABLE 5: EXPOSURE TO FOREIGN EXCHANGE RISK OF IPPS IN SELECTED COUNTRIES

Country and Period	Macroeconomic shock	Ways that Macroeconomic Shock Affects IPPs… … through foreign exchange exposure			… through the solvency of the offtaker		
	severity of economic crisis	*... currency of fuel supply*	*... currency of IPP payments*	*... foreign project debt*	*IPP share of capacity* Operating	*IPP share of capacity* Planned	*... retail tariff margin*
Indonesia 1997-98	Rupiah lost 80% GDP = -13%	LOW Local currency	HIGH Hard currency	HIGH 14% local	LOW 6%	HIGH 35%	HIGH. Retail tariffs not adequate.
Thailand 1997-98	Baht lost 60% GDP = -10%	HIGH Hard currency	LOW Local currency (*until indexed*)	HIGH Majority foreign	LOW 0%	HIGH 26%	LOW. Retail tariffs provide adequate margin.
Malaysia 1997-98	Ringgit lost 50% GDP = -7%	LOW Local currency	LOW Local currency	LOW 90% local	HIGH 34%	HIGH 51%	LOW. Retail tariffs provide adequate margin.
Philippines 1997-98	Peso lost 35% GDP = -0.5%	HIGH Majority hard currency	HIGH Hard currency	HIGH Majority foreign	HIGH 32%	HIGH 37%	HIGH. Retail tariffs not adequate.
Turkey 2001	Lira lost 100% GDP = -7.5%	HIGH Hard currency	HIGH Hard currency	HIGH Majority foreign	LOW 6%	HIGH 22%	MEDIUM. Persistent high cross-subsidy.
Egypt 2002-03	Pound lost 50% GDP = 3%	LOW Local currency	HIGH Hard currency	HIGH Local, but USD denominated	MED 11%	MED 11%	HIGH. Retail tariffs not adequate.
Argentina 2002	Peso lost 200% GDP = -11%	HIGH. Hard currency	HIGH. Hard currency	MEDIUM. Limited project Finance.	HIGH. Almost 100% of power sector private.		HIGH. Retail tariffs adequate until frozen.

Source: Adapted from model first presented in R. David Gray and John Schuster, The East Asian Financial Crisis-Fallout for Private Power Projects, Viewpoint, Note No. 146 (The World Bank, August 1998); additional data based on PESD research.

In most cases, the outcomes for IPPs are consistent with the conventional wisdom about how macroeconomic shock should affect investments. The worst performers in this group—Argentina and Indonesia—suffered severe shocks that easily propagated to the private power sector. In Indonesia, a massive devaluation of the local currency was combined with IPP contracts denominated in hard currency and a relatively large proportion of power sourced from IPPs scheduled to come online. Moreover, the state utility PLN was already in dire straits. (In contrast, the state utilities Tenaga in Malaysia or EGAT in Thailand were relatively solvent, though each had faced some troubles, which helps to explain why the Asian financial crisis had a less severe impact on those countries.) Argentina faced a crisis of similar severity when trading pressure and underlying macroeconomic trouble forced the government to abandon the currency board that had pegged the peso to the dollar. Since Argentina's entire electricity system, from natural gas supply to power generation and distribution companies was privately held with dollar-denominated contracts, the aggregate economic effect of the rapidly devaluing peso was enormous. In contrast, the countries that weathered their economic shocks the best—including Thailand and Egypt—all benefited from structural variables that lessened the impacts of shock.

These broad patterns, however, do not provide a full explanation for observed outcomes. For example, other than enjoying some leeway because none of its projects were online at the time of the Asian financial crisis, Thailand's IPPs were significantly exposed to the effects of that shock. The country was able to manage the impact on its

IPP sector in part because of the timely intervention of key policy officials and because the transparent Thai bidding process had ensured that its IPPs (none of which were yet operational) were highly competitive and politically sustainable. Similarly, despite a large shock in the Philippines and a large fraction of power that came from IPPs—both factors that would suggest high vulnerability to macroeconomic shock—the government's review and renegotiation of IPP contracts helped to calm public concerns about the cost of private power while also maintaining the confidence of investors.

In particular, countries that were able to manage the pressure from macroeconomic dislocation offer important lessons for the future. Among countries that have faced a macroeconomic disruption,[96] Egypt and Thailand have still enjoyed positive outcomes in the IPP experience. Despite seeing prices inflate as a result of currency devaluation, these countries attracted investment that is providing electricity and has proven to be politically and economically sustainable through crisis. Each country remains free to adjust the sources and terms of future investment in its power sector (and, indeed, each country is actively doing so in response to the experience in the first round). Turkey and the Philippines have enjoyed more mixed returns, largely because of a higher proportion of power drawn from IPPs (Turkey's came online after the immediate devaluation but have still seen their prices rise in local currency terms), and the fact that each country mixes projects that are priced competitively and allocated transparently with projects that are expensive and non-transparent. With macroeconomic shock, the economic sustainability and political legitimacy of the IPP programs were called into serious question. Again, without downplaying the severity of hardship that flowed from economic shock, each country has proven able to manage its obligations and to steadily improve the terms of investment in their electricity markets.

Exposure to macroeconomic instability will remain the single most important risk in power investment. Already, countries are taking steps to minimize their exposure, by turning to local capital markets (most notably in India, China and Thailand) or by giving preference to investment that accepts currency risks (notably in Thailand and in Egypt, which has prohibited the government from accepting currency risk). Investors remain wary, acutely sensitive to the fact that when it comes to macroeconomic shock, risk "allocation" is at its most illusory. New sources of capital and devaluation insurance are increasingly available, allowing some countries to continue private investment programs while minimizing risk. Nonetheless, where foreign investment is involved (and even where domestic investment is prominent but fuel sources or capital markets are hard currency dependent) currency risk cannot be eliminated entirely. With this in mind, the

[96] In rating a country IPP experience in the aftermath of macroeconomic shock, it is also important to consider that the alternative, state investment, would in many cases have faced similar currency exposure. Most countries pay for fossil fuels in hard currency, import the major equipment for power plants in hard currency. Reflecting these needs, in some countries the majority of the debt issued by state utilities is in hard currency (notably in the Philippines). The primary differences between state investment and private investment, in terms of vulnerability to economic shock is in the hard currency denominated equity returns in private projects—while significant in absolute terms, these are a small portion of total project costs. Additionally, spiraling costs for state utilities are more easily managed (or hidden) than contractual obligations in a time of crisis. Thus, the "pain" flowing from IPP arrangements in countries recovering from a crisis reflects costs that would have been borne regardless.

variation in outcomes between projects that faced similar macroeconomic disruption offers important lessons for the future. This variation reflects the country- and project-factors discussed in the sections below.

2. *Political Risk, Civil Society, and Corruption*.

Political risk in the classic sense—such as civil war or outright nationalization—has not been a significant factor in the IPP experience anywhere in the last two decades. The nearest examples are Enron's Dabhol project in India, the Hub River project in Pakistan,[97] the collapse of the IPP sector in Indonesia after Suharto,[98] and perhaps the 2001 Argentine crisis.[99] All of these cases include, to different degrees, elements of expropriation by host governments—although the full stories are compounded by many other factors, such as Argentina's macroeconomic shock, and are not solely the work of expropriators. Rather than outright nationalization, more common is a form of creeping expropriation that reduces the private value of equity assets without formally taking title; this type of opportunism usually operates through the accumulation of changes in rules, regulations, or other institutions, and less egregious refusals to honor contracts. Creeping expropriation usually arises as a byproduct of other stresses in the system, such as the buildup of social protest about rising power prices. These issues are addressed in other sections of the paper.

The topic of corruption merits separate attention. The literature on corruption and economic performance in developing countries is vast, and the literature on corruption and foreign direct investment is growing.[100] However, studies examining the impact of corruption on infrastructure investment are relatively scarce.[101] Nonetheless, corruption is widely identified as a core problem in private infrastructure investment.[102] Because of the uniquely public nature of infrastructure, including IPPs, such investment is also uniquely vulnerable to suspicions of corruption. Reflecting this, both outright political expropriation and more subtle creeping expropriation may reflect pressure that is

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[97] For discussions of the Hub river project and the dispute with the Pakistan government, *see, e.g.,* Mark Kantor, *International Project Finance and Arbitration with Public Sector Entities: When is Arbitrability a Fiction?*, 24 FORDHAM INT'L L. J. 1122 (2001); ANALYSIS OF PRIVATE POWER PROJECTS UNDER STRESS, Box 1 (World Bank, forthcoming 2005)

[98] See Kantor, *supra* note 97; Harold F. Moore, Allocating Foreseeable Sovereign Risks in Infrastructure Investment in Indonesia: Force Majeure and Indonesia's Economic Woes, 822 PLI/Comm 463, Practising Law Institute (2001); Harold F. Moore, *Restructuring International Projects: Lessons Learned from Indonesia*, 866 PLI/Comm 283, Practising Law Institute (2004); Wells, *infra* note 257.

[99] Nuñez-Luna & Woodhouse, *supra* note 82, at 14–16.

[100] *See* Shang-Jin Wei, *Corruption in Economic Development: Beneficial Grease, Minor Annoyance, or Major Obstacle?*, World Bank Policy Research Working Paper No. 2048 (1999)(reviewing the literature on corruption and foreign direct investment).

[101] *See id*.

[102] *See, e.g.*, CONNECTING EAST ASIA: A NEW FRAMEWORK FOR INFRASTRUCTURE, Joint Study of the Asian Development Bank, Japan Bank for International Cooperation, and the World Bank (2005); Laszlo Lovei & Alastair MacKechnie, *The Costs of Corruption for the Poor – The Energy Sector*, Public Policy for the Private Sector, Note No. 207 (The World Bank, 2000).

enhanced by perceptions of corruption. The Dabhol project in India (and many others, such as the Hub river project in Pakistan), apart from its other troubles, faced public scrutiny regarding allegations of corruption in its award and negotiation. Having been negotiated secretly, and with special arrangements for the large, first-time project, Dabhol was poorly positioned to face such scrutiny. (Those allegations, in turn, became a pretense for political expropriation, rather than adjudication of the underlying claims).

Like macroeconomic shock, the presence (and allegation) of corruption creates risks that can impose stress for IPPs, but it affects projects mainly through a filter of country- and project-specific institutions and choices. As a result, none of the in-depth studies written for this project identifies corruption as a major explanatory variable for project outcomes. Unlike macroeconomic shock, however, corruption does not lend itself to a neat table that summarizes the incidence of corruption and its effects on projects. Whether corruption affects projects or can be adjudicated depends on a wide array of other factors, such as broader reform of the legal system in a country; where legal processes are slow and inefficient they offer little near-term relief to investors and reformers attempting to craft sustainable private projects that navigate corrupt waters. To date, no allegation of corruption related to an IPP in any of twelve sample countries examined here (or any other country) has resulted in a full public adjudication.

As with other broad country-level factors, investors and government officials have attempted to manage the risks created by corruption (and other general political risks) by adjusting project design and contracts. Projects in countries where the incidence of corruption is higher appear somewhat more likely to rely on risk engineering mechanisms than on strategic practices. Perhaps most conspicuously, the reliance on full sovereign guarantees has occurred almost exclusively in the countries that investors perceive to be more corrupt.[103] In other risk management categories, variation is either limited (*e.g.*, all of these projects relied on long-term contracts of various times, and the vast majority included dispute resolution provisions that provided exclusive resourse ot international arbitration), or determined by other factors (*e.g.*, reliance on multilateral partners or other "prominent victims" appears to reflect mostly the status of capital markets and financing requirements of a project). Generally, investors in IPPs did not shy away from countries perceived to have corrupt business environments.[104]

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[103] Ranking the twelve sample countries according to their place in the Transparency International Corruption Perceptions Index. The six countries that scored worst on the TI Index (in order: Turkey, Egypt, India, Philippines, Argentina, Kenya) all offered sovereign guarantees for some or all of their IPPs. The exception is Kenya, in which several projects faced long delays in obtaining financing due in part to the absence of a sovereign guarantee. None of the six countries that scored best in the TI Index (Malaysia, Brazil, Thailand, Mexico, Poland, China) relied on full sovereign guarantees, although similar security arrangements were common.

[104] For example, foreign direct investment generally is less likely to include local partners in countries where corruption is perceived to be widespread. Beata K. Smarzynska & Shang-Jin Wei, *Corruption and Composition of Foreign Direct Investment: Firm-Level Evidence*, The World Bank Working Paper, at 14. Interestingly, however, IPP investment demonstrates no such pattern. For the same countries that score lower half in the TI Index (in order: Turkey, Egypt, India, Philippines, Argentina, Kenya), local partnering arrangements for foreign investors are prevalent in Turkey, India, the Philippines, and Kenya. For countries in the top half of the TI Index (in order Malaysia, Brazil, Thailand, Mexico, Poland, China), local partnering arrangements for foreign investors are prevalent in Brazil, Thailand, Mexio, and Poland. (In

The only method of reducing the risks that operating in a corrupt environment can pose to a project has been to rely on a competitive and transparent bidding process in selecting and allocating projects. This is a striking correlation. In Mexico, Thailand and Egypt, the three countries with the most competitive and transparent bidding in the power sector, no serious concerns regarding corruption have been encountered in this study. In Turkey and Kenya, projects allocated via competitive bid have remained immune to allegations of corruption that have plagued other projects in the same country that were allocated otherwise.[105] In the Philippines, civil society criticism of corruption in the IPP projects focuses primarily on the early "fast-track" projects or on unsolicited projects, both of which were allocated via direct negotiation, as opposed to projects developed under the BOT law bidding framework.[106] A prophylactic approach, such as transparent bidding, seems the only way to protect against this unique vulnerability in infrastructure investment.

3. *Electricity Sector Reform: Legal and Regulatory Framework*

The legislative and regulatory framework in the electric sector is the central institutional medium through which risk is mediated for any investment in electricity infrastructure, including IPPs. Thus, this framework usually ranks among the most important factors when investors list their concerns.[107] Perceived regulatory or legal risk can increase the cost of capital substantially.[108] However, and somewhat counter-intuitively, a series of studies have found that investment in IPPs bears little correlation to the extent or quality of legal or regulatory reform.[109] This apparent contradiction is

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China they are common as well, but for a different reason: there, local partners were required by the government).

[105] In Kenya, a newly elected government convened a commission to investigate corruption in the energy and petroleum sectors. The Nyanjacommission singled out Westmont and IberAfrica (projects allocated via a "selective" international tender) for allegations of corruption, but did not address Tsavo or OrPower4 (projects allocated via general international competitive bidding guidelines). Eberhard & Gratwick, *supra* note 78, at 7. In Turkey, government allegations of "irregularities" focused on the first round BOT projects, while largely sparing the second round BOO projects.

[106] Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (August 5–8, 2002), available at http://www.pcij.org/stories/2002/ramos3.html; Luz Rimban and Sheila Samonte-Pescayo, *Trail of Power Mess Leads to Ramos*, Philippine Center for Investigative Journalism (August 5–8, 2002), available at http://www.pcij.org/stories/2002/ramos.html; Luz Rimban, *In Haste, Government Approves Controversial IMPSA Deal*, Philippine Center for Investigative Journalism (April 2–3, 2001), available at http://www.pcij.org/stories/2001/power.html.

[107] Lamech and Saeed (2003). *What International Investors Look for When Investing in Developing Countries*, Energy and Mining Sector Board Discussion Paper No. 6, May 2003, at 9 (reporting the results of a survey of investors indicating that a "legal framework defining the rights and obligations of private investors" is the most important element in evaluating a potential investment).

[108] J.L. Guasch and P. Spiller, *Managing the Regulatory Process: Design, Concepts, Issues, and the Latin American and Caribbean Story* (The World Bank, 1999) (finding that perceived legal and regulatory risk could raise the cost of capital by 2–6%).

[109] This pattern in observed in several areas of foreign direct investment outside of the power sector. *See, e.g.*, Amanda Perry, *An Ideal Legal System for Attracting Foreign Direct Investment? Some Theory and*

explained by the fact that, in most cases, IPP investors do not look for an "ideal" legal system; rather, they seek particular IPP arrangements that apply to their particular investment and risk profile. Such arrangements usually rest on general legal and regulatory provisions,[110] but they also rest on intense particular negotiations such as those leading to an agreed PPA contract.[111] Indeed, early best-practices manuals for private participation in generation explicitly stated that establishing a coherent legal framework for IPPs was not necessary so long as a few core provisions were present.[112] These included a legal authorization for foreign investment and for private investment in power, allowing public utilities to procure power from private producers, and providing a dispute resolution mechanism.[113] Detailed regulation was left for the contracts for particular projects.[114]

Contrary to expectations, a correlation between formal reform indicators and successful country performance in the IPP sector is ambiguous, if not negative. For example, the three most successful IPP countries—Egypt, Mexico and Thailand—had relatively unreformed electricity sectors during most of the bidding and structuring of projects. Ministry-based regulation in Thailand and Egypt (which established a relatively weak regulator after the IPPs had been established) has proven effective. On the other side of the spectrum, core aspects of the reform process have introduced new risks for existing IPPs (even where the incompatibility of long-term contracts is overlooked). These episodes include, creating a comprehensive legal framework for electricity (in Brazil and in the Philippines), establishing new regulators (the Philippines), and

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Reality, 15 Am. U. Int'l L. Rev. 1627, 1646–1648 (illustrating the disparity between theory—that more efficient legal systems will attract and sustain more investment—and reality with a case study of investment in Sri Lanka, and discussing a series of hypothesis that might explain the comfort level of in vestors in an environment that provides little systemic legal certainty).

110 Pascale Michaud & Donald Lessard, *Transforming Institutions*, *in* THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE 151–163, 154 (ROGER MILLER & DONALD LESSARD, EDS., 2002) (finding that of sixty large engineering projects reviewed worldwide, including twenty IPPs, one-third required at least one changes in laws and rules, more than one-fourth required complementary changes in property rights, and more than one-third required the development or improvement of exiting frameworks for concessions or BOT ownership).

111 This is in stark contrast to private participation in distribution, which demands a coherent and overarching regulatory framework, either in public legislation and regulation or in private contracts. For a discussion of these challenges, *see generally* THE PRIVATE SECTOR IN INFRASTRUCTURE: STRATEGY, REGULATION, AND RISK (The World Bank, 1997); TIMOTHY IRWIN, MICHAEL KLEIN, GUILLERMO E. PERRY, AND MATEEN THOBANI, DEALING WITH PUBLIC RISK IN PRIVATE INFRASTRUCTURE (The World Bank, 1997); Tonci Bakovic, Bernard Tenenbaum and Fiona Woolf, *Regulation by Contract: A New Way to Privatize Electricity Distribution?*, World Bank Working Paper No. 14 (2003); IOANNIS N. KESSIDES, REFORMING INFRASTRUCTURE: PRIVATIZATION, REGULATION, AND COMPETITION, World Bank Policy Research Report (2004).

112 *See, e.g.,* SUBMISSION AND EVALUATION OF PROPOSALS FOR PRIVATE POWER GENERATION PROJECTS IN DEVELOPING COUNTRIES, IEN OCCASIONAL PAPER NO. 2 (The World Bank, 1994), at 6.

113 *Id*.

114 *Id*. ("If the basic enabling legislation exists, private projects can be structured, and obligations can be clearly defined and established in contractual agreements between the private power producer, the purchaser of power, and the government.").

unbundling generation from transmission and distribution where generation assets remain under state control (Thailand, China). In the extreme, there is Poland, where E.U. regulators have refused to authorize compensation for PPAs that are to be cancelled as that country liberalizes its electricity market.

In general, this approach succeeded in isolating IPPs from the surrounding country environment and reducing the investor-government relationship to a small set of critical contracts that, if they held, would ensure the viability of the IPP. In contrast to distribution companies, IPPs were not as vulnerable to the myriad detailed regulatory rules and decisions that were difficult to anticipate even in the most complex contracts. In the cases where custom-tailored provisions in IPP contracts have fallen prey to a shifting regulatory environment, and thus undermined reasonable expectations, one of two factors is usually at work. First, the special contracts might not allocate risks completely because the legal framework will not allow necessary provisions to take effect. Second, IPPs could become caught in the politics of power sector reform, making it impossible for government counterparties to make and honor credible contracts.

Examples of regulatory structure causing incomplete allocation of risk abound. For example, in China investors have not been able to allocate the risks surrounding tariff decisions to the authorities that set tariffs. Unlike many other countries, wholesale tariff formulas for IPPs in China are not approved until the plant is already close to commercial operations; once approved, tariffs are subject to yearly reviews with only vague standards according to which this was to happen. [115] Many ambiguities arise when governments, especially, are unable to negotiate as single actors. In China, final authority for contracting decisions is often unclear, resting somewhere between local authorities in the power bureau and provincial government, and national authorities in Beijing.[116] This arrangement has made it very difficult for local hosts and investors to anticipate the magnitude and allocation of risks. In addition, China has changed the basic methods for calculating wholesale tariffs at least three times during the IPP era, each time introducing fresh doubts for investors. In Turkey, the initial BOT law for private investment in power was passed in 1984, but ten years elapsed before the first IPP deal was signed, primarily because constitutional principles limited private participation in public services to concession contracts, which were subject to a dizzying array of overlapping approvals.[117] In 1994, facing an electricity crisis, the Turkish government passed a new

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[115] Woo, *supra* note 80, at 18–19.

[116] For example, in Intergen's Miezhouwan project, a major point of contention during PPA negotiations was precisely the allocation of risks flowing from changes in the legal or regulatory framework that could adversely affect the projects economics. Although the Fujian Provincial Power Bureau eventually agreed to accept this risk in the PPA and indemnify investors for the cost of adverse regulatory changes, its allocation was far from clear. According to lawyers involved in the negotiations, project sponsors, "while aware that such a promise required some parallel understanding etween the Power Bureau and the provincial and central governments, never inquired as to the form of that understanding … 'They did something 'internal' that we didn't really want to know about.'" Josh Eagle, *The Miezhouwan Power Project*, Stanford Law School Program in International Law, Business and Policy Case No. 001-99 (1999), at 24.

[117] Cakarel et al., *supra* note 76, at 4–7; *and see also* Catherine Pédamon, *How is Convergence Best Achieved in International Project Finance*, 24 FORDHAM INT'L L. J. 1272 (2001).

IPP framework that appeared to be more attractive for investors and led to several IPP contracts, but the Constitutional Court struck down the private law distinction.[118] Thus, in 1997, the Turkish Parliament amended the Constitution and created yet another framework, in 1997, which has held and led to 6000 megawatts of foreign-sponsored IPP generating capacity to be added to the Turkish grid.[119]

It is often assumed that liberalization and other power sector reforms are advantageous to private investors. However, reform is often a politically and technically difficult process that introduces many new risk elements for investors. For example, the unpredictable reform path in Brazil has led to an increasingly poor operating environment for thermal IPPs. The early stages of reform were dominated by a battle between the federal government utility (Eletrobras) and the state development bank (BNDES) over control and pricing of the privatization process. (BNDES won that battle and launched the privatization without fully considering the overall structure or governance of the market.[120]) Following the first round of privatization the rules governing the electric sector remained uncertain, and Eletrobras and other interests deeply vested in Brazil's massive hydroelectric industry reinserted themselves into the reform process, perpetuating a regime that protected hydroelectric plants to the exclusion of thermal units. Thermal power plants contracted in the face of this crisis had only been possible with a range of special arrangements that proved costly. These problems were amplified by a drought-caused power crisis that saw demand drop and prices rise, which produced a strong consumer backlash and fresh scrutiny for all power regulations, including those affecting IPPs. When rainfall returned to normal levels and the hydroelectric system was once again able to meet most demand, many thermal IPPs found themselves facing enormous pressure from government counterparties or from consumers upset with the high relative cost of natural gas-fired generation.

China, like other countries, began reforms when faced with constraints on the state's ability to finance necessary capacity additions. One of the first steps in this process was to dismantle the central government monopoly in the electricity sector in order to harness provincial governments in the financing effort for the power sector. Provincial power bureaus, already in existence as administrative units, were vested with increasing responsibility investment and system management, as well as receiving increasing shares of the revenue generated by electricity sales. This decision eventually created a structural incentive for local protectionism to favor provincially owned power plants, as well as making regulatory risks more difficult to allocate and manage. The Chinese IPP history is rife with accounts of non-transparent dispatch decisions favoring

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[118] Because the IPP contracts had been signed before the Court decision, however, they were allowed to retain their private status.

[119] Even the best of these mechanisms have their limits. Where projects find themselves outside of the supposedly sealed world of special IPP arrangements, foreigners find themselves once again on an uneven playing field. Bankruptcy proceedings for projects in the Philippines or in India, or corporate law disputes between investors in projects in India and Brazil, often leave foreign investors in unhappy territory.

[120] De Oliveira, *supra* note 83, at 26, 37.

local plants,[121] while local regulators found myriad ways to undermine commitments to foreign IPPs.[122]

In Thailand, resistance from EGAT to ongoing privatization efforts has invited hardball tactics from reformers in government, including efforts to starve the utility by requiring that it carry increasing amounts of the liability that flowed from the Asian financial crisis and baht devaluation. In addition to making life difficult for EGAT, this increases the credit risk for IPPs, and unfolds in a context of diminishing enthusiasm for foreign investors and a potential retrenchment of state champion firms in the electricity business. For different reasons, the primary offtakers for IPPs in the Philippines, private distributor Meralco and state utility Napocor, have each seen their creditworthiness severely undermined by a series of regulatory and court decisions.[123] While the merits of these decisions are hotly debated in the country, politics are not far from the surface in each case. Napocor has been a willing vehicle for the political manipulation of tariffs, and after the Asian financial crisis was burdened with additional costs in order to keep retail prices down during a political transition. Meralco has a long and troubled relationship with the state in the Philippines (dating back to its expropriation by Marcos from the Lopez family in the 1960s, and the return of the Lopez's from exile in the 1990s), and is often the victim of unpredictable changes in rules itself, which have caused problems for its IPP payment obligations.

In each of these countries, the challenges of reform for private investors cannot be reduced to getting market design "right" or to establishing a clear legal framework for investment. To be sure, regulatory capacity and the legal framework explain some variation in project outcomes, particularly where risk allocation is incomplete. When overall reform efforts falter the result is often also harmful to private power projects. Many of the countries in this study demonstrate a perennial inability to resolve key policy issues such as subsidized retail tariffs or favoritism for politically connected firms and enterprises, which causes constant adjustment in regulation. In the near term, regulatory stability will remain elusive. Yet some projects, discussed in Part IV.B, have been able to succeed even in this environment—through careful structuring and project design that, by luck or intent, was able to anticipate the risks that arise from sluggish and unpredictable reform.

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[121] Woo, *supra* note 80, at 27; *and see also* Noureddine Berrah, Ranjit Lamech, Jianping Zhao, *Fostering Competitoin in China's Power Markets*, World Bank Discussion Paper No. 416 (2001) at 9.

[122] Woo, *supra* note 80, at 27; Berrah, *supra* note 121, at 9; THE PRIVATE SECTOR AND POWER GENERATION IN CHINA, *supra* note 80, at 16. Out of three projects reviewed in this study (Miezhouwan, Shandong Zhonghua, Shajiao C) none has operated pursuant to the terms of the original contract. Tariffs in China are set according to a straight energy payment at a price of fen/kWh to be calculated according to a formula in the power sales agreement—each project has seen this formula disregarded.

[123] In late 2002, the Supreme Court in a hotly debated decision prohibited Meralco from including in its rate base income tax and ordered a refund to customers amounting to more than $500 million dollars. MYRNA VELASCO, SURVIVING A POWER CRISIS: THE PHILIPPINE EXPERIENCE 158 (forthcoming 2005); Peter Wallace, *When will common sense prevail?*, BusinessWorld (26 January 2004). On Napocor's roll as *de facto* policy vehicle for the Philippine government, see Woodhouse, *supra* note 75, at 22–23.

4. *The Host Electricity Market: Tariffs and System Planning*.

In addition to the general legal and regulatory framework for power sector reform, IPPs have been exposed to risks that arise from two particular aspects of the electricity markets where they operate. The first is the financial solvency of the entity (usually a state utility) that purchases the IPP's power. Solvency is mainly a function of the tariffs that the utility receives from final users and what it must pay for the power it generates and purchases. In most of the countries in this study, electricity sector reforms began at a time when the state utility was technically bankrupt and kept afloat by state subsidies because it was unable to collect revenues sufficient to cover costs. While this problem has been addressed in myriad ways, the fundamental challenge of improving revenue streams was often neglected.

In countries where state utilities are insolvent, the presence of IPPs have exposed and accelerated the need to address that underlying problem. A core expectation in the 1990s was that private ownership of at least some power generators[124] would facilitate the introduction of reforms into the rest of the sector by creating benchmarks and accountability. This has not been the case. Rather, the presence of a PPA typically increases the firm cost basis of the state utility offtaker—the amount of money that must be paid on-time, every month, at a level that covers the PPA obligations. In nearly all countries, new power is more expensive than old, and covering these extra costs has required an increase in final user tariffs or some other source of revenue.[125]

Many countries did not address this problem directly but, rather, adopted pass-through mechanisms for IPPs without fully anticipating who would bear the ultimate responsibility for paying these increased costs. These mechanisms often passed some costs all the way to retail tariffs, but preserved space for politicians to intervene and manage the effects of higher tariffs. As a result, almost all of the twelve countries examined here have either disallowed, or interfered with, the recovery of generation costs in retail tariffs. In Argentina, when the Peso declined to one-third of its original value in a matter of months the government refused to pass the higher cost of dollar-linked contracts to consumers; instead, it converted the face value of the contracts from dollars to pesos. In Brazil, thermal plants with pass-through arrangements to distribution companies that are owned by the same corporate parent as the IPP have passed costs to final consumers, which has attracted the ire (and a host of lawsuits) of consumers. The take-or-pay fuel supply contracts for these natural gas fired units require that the plants

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[124] *See, e.g.,* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 31 ("there has been an overly optimistic assumption that private ownership would push through the necessary legal, regulatory, and sector reforms").

[125] Where this happens, additional IPP obligations increase the risk for existing IPP obligations—a fact increasingly recognized by lenders, including the World Bank, which is increasingly including clauses in power sector loan agreements prohibiting borrowing states from contracting additional IPPs without approval. DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 122 (noting four IPPs that obtained World Bank support and closed within the last five years, for which the terms of Bank support included constraints on the government continuing to add private capacity without adequate justification).

"must-run," and thus the higher cost of gas is incurred regardless of the abundance of hydro electricity. In the most problematic case, private distribution company Celpe (owned by Spain's Iberdrola) is facing problems to pass-through the costs of purchasing power from Iberdrola's Termopernambuco natural-gas fired power plant. The price of power generated by Termopernambuco (R$ 57.51/MWh) is almost twice the price on existing energy auctions (R$ 37.83/MWh).[126] In response to a wave of public interest lawsuits, a federal judge ordered Brazilian regulator ANEEL to reduce from 24.4% to 7.4% Celpe's requested tariff increase to cover Termopernambuco costs.[127] Other "self-dealing" projects in Brazil have not faced problems this severe, most likely because the 520 megawatt Termopernambuco comprises such a large proportion of Celpe's generation costs that the plant has caused a 17% increase in the power tariff in the Brazilian state of Pernambuco.[128]

In the Philippines, the IPPs came under increasing public scrutiny as the additional costs from the pass through mechanism ballooned in the late 1990s. In the Philippines, *all* of the IPP purchases from the main utility, Napocor, were passed to consumers through this mechanism—a better solution would have treated the known base costs for IPPs as part of Napocor's base rate (which was not allowed increase for years) and included only the variable costs in the pass through mechanism for consumers—which magnified the visibility of IPPs and multiplied their political troubles during the tense and highly politicized period after the Asian financial crisis.[129] In 2001, in the midst of a tense political environment when the Vice-President Gloria Macapagal Arroyo succeeded President Joseph Estrada who had been ousted in a peaceful coup, the government imposed a cap on retail tariffs that, in effect, forced Napocor to absorb the difference between PPA payments and lower than expected revenues. Additionally, the dominant distribution company in the country, Meralco, has faced ongoing troubles getting power purchase costs authorized from successive regulatory authorities; in those instances, trouble has followed swiftly for Quezon Power, the only standalone IPP with a contract to sell to Meralco.[130] In Thailand, fluctuations in foreign exchange and fuel price have been passed to consumers until recently when the government asked the state utility EGAT to assume some of those risks. That shift in Thai policy reflected a new

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[126] De Oliveira, et al., *supra* note 83, at [page].

[127] *Id*.

[128] *Id*.

[129] The pass-through mechanism in the Philippines is known as the "purchased power adjustment," whose acronym (PPA) leads to some confusion for outside observers. In March 2002, NPC's base rate of P1.78/kWh had not been adjusted since 1993. However, NPC's effective selling rate to Meralco and other distribution companies was P4.22/kWh—the difference of P2.44 reflecting the adjustment for fuel costs and for power purchases from IPPs. MYRNA VELASCO, SURVIVING A POWER CRISIS: THE PHILIPPINE EXPERIENCE 66 (forthcoming 2005). This disparity reflects a combination of factors, primarily that base rates had not been adjusted upwards in ten years, that even capacity payments to IPPs were included in the PPA adjustment, and the impact of the financial crisis and currency devaluation on the Philippine IPP sector.

[130] In addition to Quezon, Meralco also buys power from two IPPs (Santa Rita and San Lorenzo) that share some common ownership and thus are better able to manage the payments crises that arise when regulators do not approve tariff changes.

approach to electricity planning that was less pro-market; it also reflected the tranche of new IPP electricity coming online.[131]

In every case in the study, the failure (or absence) of pass through mechanisms creates a burden on the state utility, the government or the IPP. The inability to recover full contracted tariffs can destabilize an IPP's contract, but whether it actually undermines the IPP depends on a host of project factors (considered below) and the allocation of the burden. The allocation of that burden depends, in part, on whether the government has the financial wherewithal to cover the sudden subsidy that is needed. Thus some of the variation in country experience is related to the size of the IPP market, measured as a fraction of the country's total generating portfolio; the larger the IPP market, the greater the stress on power purchasers (whether consumers or state utilities) or on the state coffers that ultimately must subsidize a shortfall. This helps to explain why the best-performing countries generally have been cautious in their embrace of IPPs—they contract for a few projects and maintaining a smaller percentage of their total generating capacity in IPPs. Many of the best cases for IPPs—Egypt (11%), Thailand (only 6% by 2002), and Mexico (9% in 2003)—cluster near the low end of the spectrum. In these cases, if a change in circumstances creates a special burden on government, the IPP obligations are small enough in relation to the electricity sector or government budget as a whole that the increased costs are manageable.

However, even in these countries financial strain is evident. In Thailand, EGAT's rate-of-return has eroded markedly as additional IPP power has come online—reflecting the greater cost of power purchases[132] as well as the politics of ongoing efforts to privatize EGAT.[133] In Egypt, the doubling of IPP payments has led the government to favor publicly funded plants with all capacity additions to 2007 covered by such plants.[134] This problem is particularly acute in Mexico, where the Pidiregas financing scheme—which keeps massive PPA liabilities largely off the government's balance sheet[135]—is

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[131] As always, politics is never far. In Thailand, the pressure on EGAT to assume additional costs is seen by some industry participants as a move by the executive to starve the powerful electricity utility, which has notoriously resisted a succession of attempts at privatization.

[132] Why Liberalization May Stall in a Mature Power Market: A Review of the Technical and Political Economy Factors that Constrained the Electricity Sector Reform in Thailand 1998–2002, Energy Sector Management Assistance Program (The World Bank, 2003), at 12, 25.

[133] Both the management and employees of EGAT have steadfastly resisted privatization plans throughout the 1990s. The current government, intent on at least partially divesting the state-utility, may be starving the company of funds as part of this political tug-of-war.

[134] Eberhard & Gratwick, *supra* note 77, at 33. This is a practice noted across the universe of countries with IPP experience and single national utility offtakers. *See, e.g.*, World Bank, *Private Sector Review*, *supra* note 47, at 47 (noting that in Bangladesh, "[payments] to IPPs have been kept up only by accumulating arrears to state-owned gas suppliers and by non-payment of debt service to the government.").

[135] Pidiregas exposure has been report in CFE's financial statements for several years. *See,* Comisión Federal de Electricidad, Financial statements for the years ended December 31, 2004 and 2003, *available at* http://www.cfe.gob.mx/. However, it was only in the first quarter of 2004 that the Mexican Central Bank disaggregate Pidiregas debt from general foreign borrowing by the non-banking private sector in the governments own capital account statistics—this new wrinkle revealed that *all* "non-bank private sector

coming under increasingly intense scrutiny as lenders to CFE and to Mexico question the sustainability of the utility to continue underwriting its IPP obligations while maintaining subsidized retail tariffs. The system has lasted this long, at least in part, because CFE is under the direct budgetary control of the Mexican Congress, which oversees the utility's finances as part of the national budget. If current growth in Mexico's power sector is met substantially by private sector investment, CFE's Pidiregas liability has been estimated to reach 60% of CFE's book value and 3% of Mexico's GDP within 10 years.[136]

By contrast, where IPPs account for a large fraction of generation it has proved more difficult to manage unforeseen liabilities that arise when the sector faces trouble, such as in the wake of a macroeconomic shock that dampened demand and devalued the currency. IPPs in Turkey and the Philippines account for roughly 35% and 55% of total capacity, respectively, at the time of these countries' macroeconomic shocks; that large exposure explains the massive contingent liabilities imposed in the state-guaranteed IPP programs. These countries have felt the impact of devaluation extremely keenly; for example, in the first 6 months of the Philippines' cap on the pass through of PPA costs, Napocor had to borrow US$500 million to cover its shortfall.[137] Yet in neither Turkey nor the Philippines does the high percentage of power from IPPs, and the hardship that confronts state offtakers as a result, explain the ultimate security of investor's property rights; indeed, the Philippines has found a way to manage IPP-related stress despite having close to the highest fraction of power from IPPs of all the countries in our sample. Countries that entered the IPP market later may be nearing similar problems; in Kenya, IPPs now constitute 30% of total installed capacity and capacity payments alone constitute roughly 1% of GDP. Nonetheless, the government continues to pursue more private projects.

In India, in nearly every instance IPP obligations have been a strain on state electricity boards that are unable to recover their generation costs due to low tariffs, theft, technical losses, and often poor management. In the three states with the deepest IPP markets, private generators comprise similar proportions of total generation. Looking across those three states, cost recovery is the dominant variable explaining the behavior of state electricity boards. In Andhra Pradesh, IPPs account for 12% of installed capacity, in Gujarat 10.5%, and in Tamil Nadu 10%. Performance varies among these three

borrowing" for 2002, 2003, and 1Q 2004 was for Pidiregas projects. Deborah L. Riner, *Look Who's Borrowing Now*, BUSINESS MEXICO, August 2004. This funny accounting has given pause to international commercial banks and other potential lenders. *Id.* ("Now that *what appeared to be private sector debt turns out not to be*, Mexico's foreign debt to GDP ratio isn't quite as attractive as it seemed.")(emphasis added).

136 Morgan Stanley Equity Research (Latin America), *Electric Utilities: Power to Converge*, Jan. 27, 2003, at 15.

137 MYRNA VELASCO, SURVIVING A POWER CRISIS: THE PHILIPPINE EXPERIENCE 100 (forthcoming 2005). The outlier on the upper end of the spectrum—Malaysia (with 34% of capacity from IPPs during the crisis)—relied almost exclusively on domestic inputs of capital and fuel, which also happened to minimize vulnerability to currency devaluation flowing from the IPP sector itself.

states.[138] In Andhra Pradesh, which exhibits relatively strong cost recovery in its retail tariffs and is furthest along the path of reform with a strong regulatory agency, IPPs are regularly paid (disputes largely concern accounting for cost overruns). In Gujarat, with similarly strong cost recovery but a less mature reform program, IPP's have faced chronic payment problems, but disputes have remained manageable with other adjustments (such as sourcing reliable natural gas from private companies).[139] By contrast, the state of Tamil Nadu scores lower in terms of cost recovery in retail tariffs and has barely begun reform efforts. In 2001, the Tamil Nadu Electricity Board, notwithstanding binding PPAs to the contrary refused to pay more than 2.25 rupees/kWh to its five operating IPPs, with *ad hoc* payments to cover debt service.[140] The dispute has led to one attempted arbitration[141] and has strained the relationships of project stakeholders and government officials.[142]

Second, in addition to fundamental factors related to solvency of state utilities, IPPs are also affected by key decisions related to system planning, including the capacity of the transmission system and supply-demand forecasting. Similar to the incidence of macroeconomic shock, these factors drive the level of stress that a project will face, yet do not always explain outcomes for projects. These problems of system planning are particularly evident in times of excess power supply that arise because governments systematically over-estimate the growth in demand for power even in the absence of unanticipated macroeconomic shocks. Reformers usually assume that their efforts will be successful and thus reflected in robust economic growth and higher demand for power. Moreover, reformers often assume that growth in demand will be linear rather than cyclical. Such over-estimates in demand were evident in India and China, which largely escaped the macroeconomic shock of the Asian financial crisis.

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[138] For a comparison an devaluation of the performance of these utilities, known as "State Electricity Boards" (SEBs), *see* Crisil Ratings, Consolidated Report to the Ministry of Power (Revised), January 29, 2004, *available at* http://powermin.nic.in.

[139] Another factor that likely contributes to the appearance of stability in the Gujarat experience is that the investors there (local Indian industrial interests in Essar Power, and China Light & Power in the Paguthan project) all exhibit the long-term focus and comfort operating in unstable environments that define the new breed of IPP investor. By contrast, IPPs in Andhra Pradesh and Tamil Nadu have seen more participation from "classic" IPP investors—foreign, mostly US, firms that are more likely to resist changes and go public with disputes. For more on the differences between broad categories of investor, see discussion *infra* in Part V.

[140] The 2.25 rupee policy was apparently derived by quantifying the TNEB's average cost recovery for the sale of power. *IPPs fault TNEB for poor tariff*, The Hindu (Business Line), August 28, 2001.

[141] The foreign investors in the Pillai Perumal Nallu project (El Paso Corp. and PSEG) filed an arbitration claim in January 2004 against the Tamil Nadu state government after the local partners and Marubeni refused, in an 8-5 vote of the board of directors, to allow the project company itself to file the arbitration claim. N. Ramakrishnan, *TNEB dues: PPN's 2 US partners go for arbitration, majority shareholders vote against the decision*, Business Line (The Hindu), Nov. 18, 2004.

[142] Recent discussions with some industry participants in Tamil Nadu suggest that the IPPs and the government may be reaching an accommodation. This follows on the heels of (and may reflect) the equally recent thawing in the Dabhol gridlock, beginning with the agreement between Bechtel and the Government of India during the summer of 2005 pursuant to which Bechtel dropped its arbitration claim against the Government of India.

When demand is strong and supplies are tight, investors do well; when demand is weak and the power sector faces overcapacity, investors often find themselves under pressure. When IPPs came online in Tamil Nadu the state's power deficit shrank rapidly from 15% in 2000 to 1% by 2004;[143] the IPPs offered electricity that was not only more costly than local alternatives but also increasingly less necessary. By contrast, Indian states with more acute energy shortages have been forced to sustain better relations IPPs investors, even in the face of controversies over price and other contracts terms. Andhra Pradesh's peak electricity deficit has remained above 10% and sometimes as high as 23% between 1996 and 2003, before shrinking to 2.3% in 2004, and Gujarat has spent most of the same period with peak shortages between 15-25%.[144]

The experience with IPPs in China also reveals the importance of supply and demand imbalances. The Chinese government spurred the IPP sector in the late 1980s and early 1990s in an effort to alleviate power shortages caused by the scarcity of local capital. In 1989, government forecasts anticipated an annual shortage of 50 billion kWh by 2000.[145] Between 1991 and 1998, generation capacity grew at more than 9% annually (with a slight dip in 1997); growth in consumption, however, slowed to just 2% annually by 1998. This mismatch explains why China's power plants were dispatched with a capacity factor of 53% in 1994 and only 41% in 1998; even the new state controlled generation companies, such as the Huaneng Group, saw utilization of their power plants decline.[146] For foreign IPPs, whose projects were conceived on the assumption that dispatch rates would stay high, this glut in power caused financial havoc. Chinese authorities took advantage of the glut through annual tariff reviews and to disregarded minimum off-take provisions.[147] In periods of relatively slack demand, low utilization can exacerbate tensions by raising the politically sensitive issue of "unused power" and by making private power appear more expensive by spreading fixed payments over fewer kilowatt hours.

The transmission infrastructure has also, in some cases, exacerbated the effects of inconvenient dispatch rules on IPPs.[148] The weak transmission network in China, for example, means that the supply-demand balance is unique to each province, and it is difficult to optimize investment and dispatch across the national system. When IPPs in

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[143] Data from Ministry of Power, Government of India, available at http://powermin.nic.in/JSP_SERVLETS/internal.jsp.

[144] *Id*.

[145] *Power shortages in China*, ENERGY ECONOMIST, Dec 1, 1989.

[146] Woo, *supra* note 80, at 18.

[147] Woo, *supra* note 80, at 20, *and see also* THE PRIVATE SECTOR AND POWER GENERATION IN CHINA, *supra* note 80, at 9.

[148] Among the country sample, inadequate transmission infrastructure has been a problem in China, India, Brazil, and in the Philippines. Unclear or distorted dispatch practices have been an issue in China, India, the Philippines, Mexico. *Also see* World Bank, *Private Sector Review*, *supra* note 47, at 43 (identifying core reasons that IPPs in Southeast Asia became unsustainable, including failure to meet official supply-demand forecasts, biased and unclear dispatch practices, transmission & distribution bottlenecks).

Fujian and Guangdong faced the consequences of local power gluts, potential buyers in other states that needed electricity were out of reach.[149]

5. *Host Fuel Markets*

Fuel markets are another area of vulnerability for IPPs because of uncertainty in both fuel prices and security of fuel supplies. Earlier studies of power sector reform have identified fuel markets as a source of financial imbalance in the power sector, especially when fuels entering the market (and the electricity generated from those fuels) are much more expensive than the incumbents.[150] IPPs are highly exposed to the vagaries of fuel markets, and successful firms have demonstrated the ability to minimize these risks by securing a fuel supply that is reliable and cost-competitive in the surrounding electricity market. Usually, the most successful IPPs rely on a fuel that is already established in the electric power market, which poses severe difficulties for reformers since many countries usually try to introduce fuel diversity (notably by encouraging the use of clean and efficient natural gas) at the same time that they are restructuring their power markets.

India presents a striking example of the sensitivity of IPPs to fuel market machinations. A large fraction of India's IPPs burned naphtha, a fuel that is little used elsewhere in the world for power generation. (The turbines in most gas-fired power plants can be reconfigured to burn highly refined oil products, such as naphtha, but relatively few plants actually use oil-based fuels because those fuels are normally much more expensive than natural gas. These turbines can't usually burn low-grade oil products and can't burn coal with the technologies that are widely used today; thus choices about fuel are strongly correlated with fundamental choices about combustion technology.)

In the early 1990s when India's IPP program was taking shape, potential investors faced enormous difficulties in securing fuel promises for thermal plants. Low grade Indian coal was abundant, but government agencies that controlled coal and railways were leery of delivering to power producers after weathering repeated payment default from the SEBs, and IPPs were wary of a coal supply system that was incapable of making credible delivery commitments.[151] The major alternative was to import coal or another fossil fuel, but that option was prohibitive due to high import tariffs, unpredictable import quotas, and concern that IPPs would not be able to pass increased fuel costs on to the state utilities.[152]

At the same time, the country was unintentionally building up a surplus of domestically produced naphtha, due to uneven demand for other petroleum products that

[149] Woo, *supra* note 80, at 8.

[150] Victor & Heller, *Conclusion*, *in* VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12, at [page].

[151] Navroz K. Dubash and Sudhir Chella Rajan, *The Politics of Power Sector Reform in India*, at 12, draft paper available at http://pdf.wri.org/india.pdf.

[152] *Id*.

were produced alongside the naphtha in India's refineries.[153] In 1996, the Petroleum Ministry decided to allocate this naphtha to support the development of 12,000 megawatts of combined cycle generation to be fired on natural gas and naphtha; since natural gas supplies were limited at the time, naphtha became the principal fuel.[154] However, in 1998, when some naphtha burning plants were coming online (e.g. Dabhol) and several others had been awarded (e.g. a series of projects in Andhra Pradesh), the government deregulated the price of naphtha, which doubled within the year alongside the rising international price for crude oil. The ensuing price increase for power purchased from naphtha-fired IPPs precipitated a host of problems between the SEBs, which were reluctant to purchase the expensive electricity, and IPPs. Vulnerable to high fuel costs, the IPPs struggled to obtain allocations of less costly price-controlled gas in the state-managed gas market, a task that proved to be difficult because gas quotas were awarded via a political and non-transparent process[155] and supplies were often unreliable.[156]

Projects that have managed to secure gas supply contracts in India's nascent private gas market have seen a marked improvement in enforcing the offtake provisions of their PPA's with the state electricity boards. These contracts include two-way take-or-pay provisions, meaning that the supplier bears the risk of non-delivery and 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 gasfield developments to secure such private contracts and move away from expensive naphtha firing. Essar had weathered the financial difficulties of running on naphtha in part because the project is primarily a "captive" plant—its main purpose is to provide power to a massive steel plant owned by the project developers, although the project is also sized and operated so that it sells power to GEB. CLP Paguthan, on the other hand, has faced serious difficulties with the Gujarat Electricity Board while firing only on naphtha; when it switched to private natural gas it was able to lower its tariff, which made its dispute more manageable, and the GEB's payment record has since improved.

IPPs in both Brazil and the Philippines found themselves in poor circumstances because of the fallout from poor planning and financial exposure in their natural gas markets. The Philippines government, eager to provide a market that would encourage Shell to develop the offshore Malampaya field (estimated to have gas reserves in the range of 400-450 million cubic feet per day for 20 years[157]), pushed through several gas-fired IPPs. Contracts for these projects were signed in late 1997 just before the Asian financial crisis broke. As demand for power dipped between 1999-2002, the state utility

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[153] *Id*.

[154] Rahul Tongia, Stanford-CMU Indian Power Sector Reform Studies, at 12 (February 4, 2003).

[155] Explain the inter-agency panel that awards gas.

[156] Gas supply contracts with GAIL (the Gas Authority of India, Ltd.) at the time contained no penalty for failure to deliver specified amounts of gas.

[157] PRIVATE SOLUTIONS FOR INFRASTRUCTURE: OPPORTUNITIES FOR THE PHILIPPINES, Public-Private Infrastructure Advisory Facility & the World Bank Group (2000), at 23.

Napocor found itself saddled with excess capacity just as this 2500 megawatts of new natural gas-fired electricity came online along with another 800 megawatts of new hydro IPPs. The costs for many of these projects fell directly on Napocor, and the ensuing drain on Napocor's finances contributed to public and political dissatisfaction with the power sector generally and exposed IPPs to public criticism and eventual renegotiation.[158]

Brazil's experience with gas-fired IPPs is the most glaring example of fuel market exposure in all the countries examined in this study. Alongside its power market restructuring, the Brazilian government pushed for gas-fired IPPs in an effort to diversify away from nearly complete dependence on hydro and to provide a market for growing gas supplies from domestic wells and imports from a government-backed pipeline from Bolivia. Yet Brazil's natural gas markets, at the time, were immature in size and regulation[159] and highly vulnerable to political decisions. Even the decision to provide a market for natural gas from Bolivia was partly politicized.[160] In the face of the looming power shortage in 2001-02 due to low rainfall levels, the Brazilian government launched an ambitious priority thermal program, identifying forty-nine projects for development. Only a small fraction of these projects ever reached commercial operations, yet by 2002 it was clear that Petrobras (which had been directed to provide gas to the projects) lacked gas for even these plants. In an environment of scarcity, natural gas-fired plants faced new and prohibitive regulations, including one decree that banned any contracts for power above the amount that could be generated based on the actual amount of natural gas Petrobras could deliver. Facing a rapidly eroding operating environment, the outcomes for IPPs diverged according to their fuel supplies and contracts. MPX's Termoceará in the north of the country has had chronic problems getting gas delivery. The project competes for gas with another IPP that has a take-or-pay contract with the local distribution company (Endesa's Termofortaleza) and also with numerous industrial offtakers. Because Termoceará sells electricity on a merchant basis, and because Petrobras pays a revenue guarantee to the project whether or not the plant actually produces electricity, Petrobras finds it easier to cut gas delivery to that plant than to other users. Thus, during a mini-drought in 2002—which affected only the north of Brazil due to transmission constraints—Termoceará was, in principle, well-situated to provide power at a healthy profit; yet the plant sat idle for lack of gas. With no relief in sight, the project's sponsors sold the IPP to Petrobras in early 2005 for $120 million—seemingly a healthy profit for a plant that originally cost $100 million.

[158] With dollar-denominated power purchase costs increasing and the peso losing value rapidly, a 2001 law barred cost recovery for IPPs that had not registered with the Electricity Regulatory Board by Dec. 31, 2000. For no apparent reason, several of the largest or most expensive IPPs, including Ilijan, Casecnan, and San Roque, were not registered by Napocor by this deadline. This meant that while the state utility was obliged to pay its full obligations under the contracts, it was not allowed to recover these costs in its grid rate to distribution companies and other offtakers. This law also called for a full review of Napocor's obligations under its IPP contracts that eventually grew into the renegotiations discussed later in the paper.

[159] On the disconnect between the regulation of natural gas markets and electricity markets in Brazil, see L.A. Barroso, B. Flach, R. Kelman, B. Bezerra, S. Binato, J.M. Bressane, and M.V. Pereira, *Integrated Gas-Electricity Adequacy Planning in Brazil: technical and economical aspects*, paper presented at IEEE General Meeting, San Francisco, June 15-16, 2005.

[160] De Oliveira, *supra* note 83, at 38.

In contrast, two of the most competitive IPP markets—Mexico and Thailand—owe their success in part to master gas supply arrangements that create more predictability in gas pricing and the pass-through of fuel costs. In both, the national electricity utility (CFE in Mexico, EGAT in Thailand) established binding agreements with the state-owned gas supplier (PEMEX in Mexico, PTT in Thailand). So far, these agreements have reduced the exposures of IPPs that operate in the middle between primary gas supply and the offtake of their electric power. (The third country where IPPs have consistently delivered low prices, Egypt, simply provides gas to its IPPs at highly subsidized prices).[161] Such provisions to reduce risk have made these countries darlings for IPP investors, but these arrangements have proved difficult to sustain. In Thailand, new tenders for IPPs are facing fresh difficulties securing competitive fuel contracts, not least because PTT is weighing a possible entry to the electricity market. (Private investors fear competing in a market where the gas company is both fuel supplier to all and competitor for electric service.) In Mexico, the government has gradually moved away from a policy that had required CFE to assume the risks associated with gas pricing, in part because gas prices (which are partly indexed to the U.S. market) have risen sharply since 2001. Current guidelines for IPPs in Mexico shift substantially all fuel risk—including procurement, contracting, pricing, and quality—to the private operators.[162] Investors in Mexico now worry that they will be unable to compete directly with state-owned plants that have special fuel arrangements.[163]

B. Projects: Design, Incentives and Contracts.

As recounted in Part IV.A, a host of exogenous and institutional factors that are beyond the direct control of key stakeholders help to explain the observed pattern of outcomes for IPPs. Yet these factors are far from fully determinative. Even in cases where the institutional environment appears to yield highly successful outcomes (e.g. Mexico, Thailand), questions are arising about the sustainability of IPP arrangements—such as the special payment regime in Mexico that is inflating the government's exposure to foreign exchange liability. In cases where macroeconomic shock and political controversy have engulfed the IPP sector (e.g., China and the Philippines) the outcomes for IPPs have varied. In cases where power sector rules are unstable and unpredictable (e.g., Brazil) or offtakers are insolvent (e.g., India)—factors that would imply disastrous outcomes for IPPs—many projects have nonetheless been successful for investors and hosts alike.

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[161] Eberhard & Gratwick, *supra* note 77, at 23.

[162] John Schuster and Bob Marcum, *Emerging Fuel Supply Issues in Mexican IPP Project Financing*, 8 J. OF STRUCT. & PROJ. FIN. 40, 42 (2002).

[163] The following distinction between financial/legal methods and strategic methods of risk management draws primarily from Theodore H. Moran, *The Changing Nature of Political Risk*, *in* MANAGING INTERNATIONAL POLITICAL RISK 7, 11 (Theodore H. Moran ed., 1998). A similar distinction is offered from the perspective of a political risk insurer, *see* West, *supra* note 86 ("there are three risk management strategies that project developers can pursue: transfer, risk minimization and loss prevention, and insurance").

This section examines factors that vary at the level of individual projects—"project factors"—to complete the explanation of why outcomes vary. The core argument is that while country factors broadly determine the levels of stress on a project, the actual impact on projects is mediated by factors that project sponsors and their hosts control. Thus there is enormous variation across the project experiences, and much of that variation does not appear to correlate with broad country factors.

At first, the argument that project design is the ultimately determinative factor may seem intuitive—even mundane. After all, the wave of IPP investment in the 1990s was based heavily on the idea that risks could be managed through project-specific contracts; investment often flowed to countries where (and when) appropriate contracts were offered. This section goes one step further, by distinguishing two categories of project-level factors. The first is the arsenal of "risk engineering" measures that include legal and financial instruments designed to price and allocate risk precisely, along with the project contracts that codify these arrangements into binding obligations.[164] Risk engineering, as discussed above, was conceived with the goal of containing risk by constraining the government's discretion with respect to a given project. The second category includes measures designed to anticipate (and manage) risks that are likely to arise and gravitate towards vulnerabilities in a project but are difficult to manage through contracts.[165] This category—"strategic management"—contains instruments and decision-making procedures that are intended to make the project a less likely target for government opportunism and less vulnerable to unintended squeezes such as from fuel markets. While the first category contains necessary elements, such as carefully designed contracts that animated much of the IPP market through the 1990s, it has failed to satified the premise that risk can be managed by identification and allocation. The second category, while more amorphous, has been a more important determinant of outcomes in the IPP experience.

1. *Risk Engineering: A Failed Promise.*

At their core, western firms are accustomed to planning investments for which the risks can be evaluated *ex ante* and captured in prices and contracts.[166] This task is

[164] *Id.*

[165] *Id.* A similar distinction is made by Miller & Lessard in an extensive review of success and failure in large engineering projects (including roughly thirty IPPs). Miller & Lessard distinguish between "decisioneering" approaches to risk management, which attempt to calibrate discounted cash flows to predictions about future risk, and "managerial" approaches to risk management, which attempt to "match risks with strategies" in order to "influence outcomes." *See* Donald Lessard & Roger Miller, *Mapping and Facing the Landscape of Risks*, *in* THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE (ROGER MILLER & DONALD LESSARD, EDS., 2002) 76–92, at 85–86.

[166] *See, e.g.*, HERNANDO DE SOTO, THE MYSTERY OF CAPITAL: WHY CAPITALISM TRIUMPHS IN THE WEST AND FAILS EVERYWHERE ELSE (2000); Benjamin C. Esty and William L. Megginson, *Creditor Rights Enforcement and Debt Ownership Structure: Evidence from the Global Syndicated Loan Market* (reviewing the contractual mechanisms deployed to control the particular risks of project finance transactions in developing countries).

particularly challenging when the investment is a power plant that sells to a state-controlled utility in a developing country. A power plant has a long economic lifetime, which implies the need for the investor to anticipate and control outcomes far into the future. State-controlled utilities that purchase the power are particularly ill-equipped to make credible long-term commitments in part because they are vulnerable to political interference. And developing countries, almost by definition, have state institutions that are weak and in flux; the rules that govern the economy generally and the electric power system in particular can be highly variable, which undermines the credibility of contracts that include distant commitments. In such settings it may be impossible to perform some tasks that are essential to the western theory of investment planning, such as ensuring the availability of efficient legal remedies if a contract is broken.

Nonetheless, investors in IPPs were neither blind nor naïve. They adopted a canon of measures intended to engineer risks and to transform the risk management process into something that was supposed to look and operate like the contracts and institutions that were already familiar to western investors. The canon has had four main elements: (a) at the core, a series of contracts (known collectively as “project documents”) that capture the key commercial bargain between government and investor[167], (b) payment security arrangements designed to ensure a regular flow of project income, (c) multi- or bilateral partners (lenders and insurers) whose presence is thought to deter contract breach by the host government, and (d) offshore arbitration designed to circumvent difficulties with local courts and improve the ultimate enforceability of contract terms. When stressed, these mechanisms have exhibited mixed success. Many of the options introduce new risks of their own. Other defensive measures such as offshore arbitration have proved difficult to invoke and apply only when the setting for the investment has deteriorated so badly that the project is no longer viable.

(a) Contracts.

For an IPP, contracts capture in excruciating detail the bargains among key project stakeholders, and are often bolstered with various bells-and-whistles intended to make them more enforceable. Contracts manage risk by specifying precise obligations and responsibilities for parties to the contract. Bankers and lawyers are particularly comforted by these arrangements because they believe it is possible to evaluate the risk and return from a project so anchored in this type of contract. In practice, the utility of these provisions in signaling the IPP’s financial future depends critically on a host of institutional factors; reliable credit rating mechanisms, transparent accounting, and meaningful legal adjudication and enforcement, among many others. Absent this

[167] In most cases this documentation revolves around a long-term power purchase agreement that specifies quantities and prices for power over the life of the project. However, in decentralized or privatized electricity markets the power sales may not involve government entities. In these cases, key bargain offered by government is found elsewhere; in Brazil the “self-dealing” projects were guaranteed full-pass through of costs via associated distribution companies; in Argentina, the pass-through arrangements and dollar-peso currency peg played a similar role.

institutional infrastructure, contracts fare poorly in anticipating risks and specifying solutions.

Because contracts specify boundaries but are inherently incomplete, the durability of contracts and the nature of any changes help to illuminate the investor-government relationship. While an imperfect indicator of overall project success, the simple question of whether contracts hold is a useful starting point to examining project outcomes. Out of thirty-three projects reviewed in-depth for this study, eleven have undergone mutual or cooperative renegotiation[168] and eight have faced unilateral renegotiation or non-payment.[169] Among these, four have ended in arbitration or litigation.[170] Only twelve have held in a strictly formal sense—a group dominated by cases where country factors have shunted any severe stresses away from the projects and where projects have been tailored closely (by accident or design) to the risks of the surrounding power market.[171] Notably, six of these eight cases are in Mexico and Egypt; in Mexico the absence of any substantial macroeconomic instability means that potentially vulnerable aspects of the IPP arrangements there have not been stress tested, while in Egypt the extremely low prices for the IPPs and the relatively low proportion of private electricity as a share of total generation have helped that country maintain payments in the face of the devaluation of the local currency between 2002-03. The Brazilian cases reflect circumstances in which payment and offtake risk is almost entirely eliminated: Caña Brava in Brazil is a hydro project that exists within a system that is highly protective of hydroelectric plants; Norte Fluminense in Brazil sells to a distribution company (Rio's Light) owned by the same parent company (Electricité de France).

That just more than one-third of the contracts have held reflects a wide array of factors discussed in this paper. Nonetheless, and quite conspicuously, more than half of the renegotiations have been mutual or cooperative, rather than opportunistic. This dispersion, and the prevalence of adjustments to contracts reflects basic asymmetries of

[168] "Mutual" or "cooperative" renegotiation refers to a renegotiation that is not accompanied by a public dispute and that (in the end) does not appear to have a significant financial impact on the project. These include: Termoceará (reflecting a healthy buyout price), Uruguaiana, Shajiao C, GVK Jegurupadu, Lanco Kondapalli, Essar Power, IberAfrica, Pagbilao, Quezon, Casecnan, Independent Power.

[169] "Unilateral" renegotiation refers to a renegotiation that is undertaken with substantial government pressure, non-payment or other coercion and which produces a result that has a significant financial impact on the project. These include: Macaé, Miezhouwan, Shandong Zhonghua, Paguthan, PPN Power, ST-CMS, Cavite, Elcho, ENS. The two Polish projects (Elcho and ENS) are difficult to place, as pressure to cancel the contracts as part of EU accession is ongoing and has not been resolved yet—they are included here in the expectation that the PPAs will be cancelled. Additionally, although the study did not include detailed examination of specific projects in Argentina, every IPP there has faced unilateral renegotiation in the conversion of their contracts to pesos.

[170] The arbitrations or litigation cases are Macaé (Brazil), PPN (India), Casecnan (Philippines), Cavite (Philippines).

[171] These are dominated by projects in Mexico (Monterrey III, Merida III, Rio Bravo), Turkey (Trakya Elektrik), and Egypt (Sidi Krir, Port Said, Suez). Outliers include EDF's Norte Fluminense in Brazil (which sells to a distribution company that is owned by EDF as well), Cana Brava in Brazil (which is a hydro plant in Brazil and faces few risks other than environmental permits), and Essar Power in India (which is primarily a captive power plant).

information and perspectives, and the limits of legal instruments as a means of controlling the consequences of that asymmetry. There is, in practice, very little agreement regarding how to evaluate the costs and benefits of private power, particularly when compared with state-owned plants. This debate is undertaken in an environment of scarce and imperfect information that, in many ways, exacerbates the affect of the various factors discussed in this paper.

First, striking difficulties in evaluating the cost of private plants are exacerbated by inevitable comparisons to state developed projects. The price of electricity from a given power plant reflects a host of factors that are unique to that project, including fuel supply and delivery prices, equipment prices and interest rates at the time of construction, site-specific challenges in managing construction and operations, and many others. The data that determines final prices from a plant are often confidential, as is data on the financial performance of the project company. Nonetheless, conclusions regarding prices, and in particular comparisons to state owned projects, are common. This debate has some common refrains. First, private and public power plants are organized in ways that provide incomparable information about costs. Private plants are financed as standalone investment vehicles that, by necessity, include hard accounting on all costs, market returns, and risk premia that inflate the required returns where the setting is prone to unfavorable changes in circumstance. By contrast, state-owned power plants often operate on extremely loose terms relative to their private counterparts—with limited offtake requirements, flexible payment schedules, and often poor accounting of cost and revenue. Determining the cost benchmark for state owned plants is often impossible—indeed, many countries looked to IPPs as a potential means of introducing a competitive benchmark to the industry.

Second, these information asymmetries, in combination with rigid contracts, make it difficult for regulators (whether in independent bodies or within ministries) to resolve disputes or respond to changes in circumstances even in legitimate and evenhanded ways. Successful projects have often adjusted terms and expectations in cooperation (even if somewhat tense) with host country officials. The information and space necessary for such adjustment is often constrained; for private plants such information is usually confidential (in part because operations are a main way that these plants obtain profits higher than the benchmarks that were used originally to justify the original contract), and project structure involves overlapping contracts among many stakeholders holding a veto over changes. When circumstances change, even cooperative adjustment is extremely difficult. Operating in an environment of scarce and imperfect information, both investors and governments may re-evaluate risks and adjust their view of acceptable returns.

Third, there are asymmetries in the perception and rhetoric of why private power is costly. Government officials and consumers note that private plants are laden with inflated risk premia and often suspect that special deals do not merely reflect market risk—after all, few governments can admit publicly that their own policies give rise to the need for inflated risk premia—but rather are the work of negotiations that are laden with corruption. Investors, for their part, argue that first-of-a-kind projects are often

costly, and that state owned plants are inappropriate benchmarks. Investors also argue that their prices reflect uncertainties surrounding government decisions in many fundamental ways including fuel and siting choice, and dispatch levels.[172]

Fourth, the most transparent measures of cost—such as those used for ordering dispatch of power—are not designed to elicit information about long-term costs and plant performance. Merit-order dispatch systems, where they exist, emphasize information about short-term costs (which are relevant for dispatch) but are not equipped to reveal long-term costs (which are relevant for investment planning). Looking across the full sample of projects, IPPs are disproportionately gas-fired and thus they tend to have operating costs that are higher than the existing fully amortized baseload plants that state utilities operate. Moreover, IPPs tend to score better on other attributes, such as low environmental footprints and operating efficiency, but dispatch systems do not reveal that information. The result is that excessive attention to the short-term can leave new IPP plants either idle or running according to contracts amid claims that the plants are too costly.

Every country examined in-depth for this study exhibited a debate about the relative cost of private and public power. Such debates simmer in an environment of institutional weakness, characterized by the lack of a credible mechanism for evaluating the fairness of any given IPP arrangement. There is rarely an established institutional framework for evaluating and resolving these unfamiliar disputes, nor a body of practice that offers guidance.[173]

Dissatisfaction with IPPs almost always arises because prices swell markedly—often due to a change in circumstance—which animates the private/public power debate and makes the original contract for IPPs vulnerable. Regardless of the contract terms, government officials or state utility managers have no shortage of ways to disrupt a project.[174] This pressure is almost always reflected in the fundamental contracts for a project—primarily because the risk engineering approach had intended to bind the hands of the host, and thus any change in circumstance almost by definition required first that the host find a way to unbind his hands and gain flexibility.

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[172] In India, for example, a perceived surplus of naphtha led the government to encourage IPPs to use the fuel; a later decision to deregulate naphtha prices sent costs soaring. In turn, naphtha plants were dispatched for fewer hours, which afforded a lower base for amortizing capital costs. Another common complaint is that low dispatch leads to high per kilowatt prices by reducing the units across which fixed costs can be spread.

[173] These problems are hardly unique to emerging markets. It is nearly an axiom of power market reform that entrenched interests in the electricity sector are likely to oppose new initiatives. For example, that was the United States' own experience with IPPs, which muddled along for several years, constrained by investor uncertainty and constant litigation. David Baughman & Matthew Buresch, *Mobilizing Private Capital for the Power Sector: Experience in Asia and Latin America*, Joint World Bank-USAID Discussion Paper (Nov. 2004), at 12.

[174] Moreover, investors seem to have fared poorly in evaluating the risk of creeping expropriation, as opposed to more classic political risk events. *See* Weder & Schiffer, *supra* note 21.

Typically, these weaknesses concentrate stress on the contract where terms and expectations are ambiguous. For example, competing definitions of "force majeure"—a provision that allows parties to reopen the terms of a contract—have created ongoing problems for power sector investors facing severe systemic stress,[175] as have legislatively mandated tariff reviews in China. Similarly, conflicts about the application of regulatory or legal standards can propagate into stress on contracts. For example, both GVK Jegurupadu and Spectrum Power in the Indian state of Andhra Pradesh have not received payment for full invoices—closer examination reveals that the amounts in dispute flow from cost overruns in construction, above originally contracted amounts. In India, the Central Electricity Authority approves project costs, but officials in the individual states also conduct their own assessments; overlapping jurisdiction allows government officials to avoid a firm decision, leaving the IPP to be paid only according to the original contracted amount. In China, failure to construct IPP plants according to the detailed (at times, inefficient) technical designs and regulatory manuals has been used by regulators to justify not accepting power on contracted terms. Finally, the risks confronting a project may simply outstrip those possible to be captured by a contract, such as where macroeconomic shock dashes every expectation and assumption underlying the parties' contract. With time, investors responded to these weaknesses and the gaps in interpretation with more detailed contracting, but in practice such effort seems to be wasted because of the challenge in anticipating the myriad difficulties and their legal remedies that could arise for a project. More severe systemic stresses are not managed by contractual anticipation; they merely reappear as pressures in a new locus of ambiguities and uncertainties.

(b) Payment Security and Official Credit Support.

The project partners in IPPs have relied on a wide array of arrangements to secure payments. These instruments include sovereign or corporate guarantees, escrow arrangements and letters of credit—all designed to bolster confidence around a predictable stream of payments from offtakers whose own financial situation, usually, gives cause for concern about reliability. Such arrangements appear to be necessary conditions—in part for reasons of payment security and notably because project bankers and lawyers who control the financing of these projects demand them—but they are not sufficient to assure a contracted outcome. Indeed, the IPP experience reveals no more than a tenuous relationship between the layers of official credit support and the severity of pressure to alter contracts. As with the contracts themselves, officials who want to impose stress on a project have many ways to avoid these so-called secure arrangements.

Sovereign guarantees are prominent on this list, largely because they operate over a long period of time and allocate risk of nonpayment to the actor that, in principle, has the greatest capacity to intervene and fix most problems that befall a project. Many of the countries in our sample have employed such provisions, including Egypt, India, Turkey, and the Philippines. In addition to these cases, the projects in Mexico and Thailand have *de facto* guarantees because the state-owned utilities that purchase the

[175] Regulation by Contract, *supra* note 112.

power (CFE and EGAT) are both supported by the national budget in their respective countries. Sovereign guarantees are associated with strong country performance, even in the face of macroeconomic stress. However, in light of competing factors at work in these countries, sovereign guarantees are not the sole factor at work; nor does it appear that sovereign guarantees are even a significant factor. In assessing the importance of these factors, the experiences of the Philippines and India, both countries that have varied their use of sovereign guarantees across projects, are particularly illuminating; yet none of this variation actually explains the range of project outcomes.

In the Philippines, projects initiated before 1995 had full sovereign guarantees, but after that date the government began limiting its use of guarantees for the state utility Napocor[176]; despite this change, the outcomes for the entire IPP sector reflected primarily the consequences of the country's macroeconomic shock and the subsequent 2002 government review and renegotiation of IPP contracts (*discussed below*). That review presented a delicate moment in which the fortunes of individual projects could easily have diverged; in fact, the existence of a full guarantee did not correlate with different results in that renegotiation. In India, the government offered sovereign guarantees to the first eight (so-called "fast track") IPPs, including the infamous Dabhol project. In part because of the political controversy that spewed from the Dabhol guarantee, it subsequently scaled back guarantees for subsequent projects; GVK and ST-CMS, for example, only received guarantees for payments on foreign debt. In both cases these payments were met without invoking the guarantee, but it is not clear that the guarantee was even relevant; the outcomes from these projects have turned on managing problems that are substantially similar to other projects in the state that do not have the benefit of a sovereign guarantee. GVK's good performance is due mainly to the project's reliance on natural gas, and its location in a state (Andhra Pradesh) that has been keen to promote stable relations with foreign investors. In the case of ST-CMS, all of the projects in Tamil Nadu have faced similarly reduced payments from the electricity board; yet most have received sufficient revenue to cover their debt service, regardless of whether they had a sovereign debt guarantee.[177] This treatment likely reflects hesitance on the part of Tamil Nadu officials to invite conflict with the project's commercial bank lenders.

In general, governments have objected to using sovereign guarantees, and many countries have attempted to phase them out as the IPP sector matured. They have viewed such guarantees, perhaps correctly, as necessary to assuage investor fears in the early stages of a novel but risky investment scheme. State utilities have often chafed at tariff guarantees that they view as subsidies for IPPs. Moreover, sovereign guarantees are, perhaps increasingly, viewed with skepticism as investors look at the underlying fundamental factors to determine whether such a guarantee is credible. This is evident in

[176] INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002); Study on the Restructuring of the Financial Liabilities of the Power Sector: Final Report, March 2000, at 7–8, tbl. 5.

[177] The only exception is PPN Power (which did not have any central government guarantee), which is distinguished by its large size, by firing on expensive naphtha, and by very poor relations among project investors. PPN Power seems over-determined to suffer financial trouble.

Mexico with the growing liabilities and thus declining credibility under the Pidiregas payment arrangements

The principal value of sovereign guarantees for foreign investors may be to substitute the host national government for the contractual offtaker as the legal counter-party if contracts are breached. (A similar shift in agency arises with the use of other instruments, such as claims under bilateral investment treaties or subrogated political risk insurance.) In these settings, the interests of the investor may be favored in multiple ways. First, host national governments may feel more obligated than other parties to abide by treaty commitments to submit disputes to international arbitration. Second, the national government is more likely to possess offshore assets on which courts outside the defendant nation may levy arbitral judgments. Third, host national governments may be more subject to political pressures by the investors' host governments. However, nothing in the study indicates that these measures have been cost-effective deterrents or determinants of project outcomes. Instead, the stability of contracts seems more closely related to the management of counterparty risk (*discussed in the next section*)—where the offtaker is a national utility, the addition of a sovereign guarantee seems to add little marginal benefit.

In addition to sovereign payment guarantees, investors in a few cases have relied on escrow arrangements or letters of credit to ensure payment. Where they are made operational, these mechanisms have a promising record. Similar to sovereign guarantees, there is some overlap between escrow arrangements and strong performance in the face of stress; for example, IPPs in Andhra Pradesh (GVK and Kondapalli) and in Kenya (Tsavo) have operating escrow protections, and in each case have seen their basic commercial arrangements preserved in the face of stress. As with other protections, escrow arrangements have their limits—Dabhol has certainly not been saved by the overlapping guarantees it received from state and central government authorities, including a sovereign guarantee for part of the project from the federal government and a series of letters of credit and escrow arrangements.

Where formal guarantees do not exist, risk engineers have invented a wide array of other arrangements designed to create similar levels of confidence around payment streams. In China, investors have sought arrangements that shifted the risk of payment shortfalls to local partners. (Most Chinese projects were required to carry substantial local participation, which often came from entities that were closely bound with the local government.) For example, in Shajiao C, a mechanism of this nature called for indemnification of the foreign investor for reductions in the tariff. When provincial authorities lowered the applicable grid rate, the local partner (which was essentially an arm of the state government) paid the difference under the indemnification clause.[178] The Shandong Zhonghua project, when faced with drastic reductions in the tariffs paid for its greenfield units, adopted a similar scheme by reducing payments related to project operations that were to be paid to the local government partner (this arrangement, however, was not part of the original contract, but implemented in response to tariff reductions). Accounts of these types of mechanisms are common in China; their

[178] *See* Woo, *supra* note 80, at 58, 59.

effectiveness, however, critically depends on enforcement of contracts, and it is unlikely that their overall protection has been strong outside of a few prominent cases.

(c) Prominent Victims as Political Risk Management.

Private investors, particularly foreigners, often try to deter governments from making adverse decisions by involving prominent entities as investors. The hope is that government will avoid trampling on big toes.[179] This strategy usually appears in one (or more) of four principal ways: (1) co-investment (i.e., equity) by a multilateral lending institution, (2) lending by international development banks, either directly or as guarantees for commercial loans, (3) risk guarantees or political risk insurance, and (4) reliance on the presence of commercial banks that are critical repeat players in financing governments all over the world.

The information necessary to investigate the scope and effectiveness of this strategy is almost impossible to obtain in a systemic and public form.[180] This is due primarily to the incentives of the parties involved. Governments do not want to admit acquiescing to pressure from such entities; multilateral or foreign government entities do not want to appear to be bullying sovereign counterparts; political risk insurers do not want to reveal their methods or settlements for fear that that would affect future claims and premia.[181]

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[179] *See, e.g.*, Louis T. Wells and Eric S. Gleason, *Is Foreign Infrastructure Investment Still Risky?,* HARVARD BUSINESS REVIEW, Sept/Oct. 1995 ("A number of foreign investors in developing countries have sought to involve international institutions in their investments. They believe that a government that acts against a project that includes, say, the International Finance Corporation recognizes that it risks being cut off from further funds by the World Bank group."); DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 110 ("As one commercial banker stated, the losses experienced by commercial banks in power sector transactions were substantially greater in the industrialized markets of the U.K. and the U.S. than it ever was in emerging markets. Commercial banks generally survived most of the power project failures by recovering the loans due to a strong guarantee and risk insurance framework backed up by MDBs and ECAs."). *And see also*, Marco Sorge and Blaise Gadanecz, *The term structure of credit spreads in project finance*, Bank for International Settlements Working Paper No. 59 (2004) (finding that the presence of multilateral or ECA support is far more prevalent in project finance transaction, particularly in developing countries, and can lower credit spreads by almost 30% on average).

[180] In one starting point, the World Bank notes that MIGA has issued 72 guarantees to 39 electricity investments, 32 of which were in the generation sector. Of this number, one claim has been paid ($15 million for a project in Indonesia) and five disputes have been "mediated." World Bank, *supra* note 47, at 23-25. *See also* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at 139 ("In the about 20-year history of the World Bank [partial risk] guarantee, the World Bank has never had to pay out a claim under the PRG. This is ostensibly because the World Bank relies on its 'halo effect' as the preferred creditor, to put strong pressure on the government in order to obtain compliance.")

[181] *See, e.g.*, West, *supra* note 86 ("Why is little said or written about [the role of insurers in resolving disputes]? One might answer that question with a question: What national investment insurer from an OECD country wishes it known that it has convinced, cajoled, pressured, induced, persuaded, or otherwise reasoned with a developing country, so that a specific investment was not expropriated. No one. For similar reasons, it is not in the interest of the investor who has benefited from such a dispute resolution to publicize it. Silence about such events obviously makes good business sense for an investor who wishes to continue to operate. The host country, in turn, is not eager to publicize the resolution of a conflict or dispute with foreign investors for two reasons. First, it is difficult for most governments to admit publicly

Given these limitations, Figure 3 provides a rough approximation of the risk mitigating role that prominent international partners have played in the IPP experience. This figure shows the relative ability of IPPs with prominent international partners to manage four types of stresses that are often proximate determinants of poor project outcomes: fuel supply, dispatch, non-payment by the offtaker, and renegotiation.

FIGURE 3: RISK MITIGATION EFFECTS OF MULTI- AND BILATERAL LENDERS

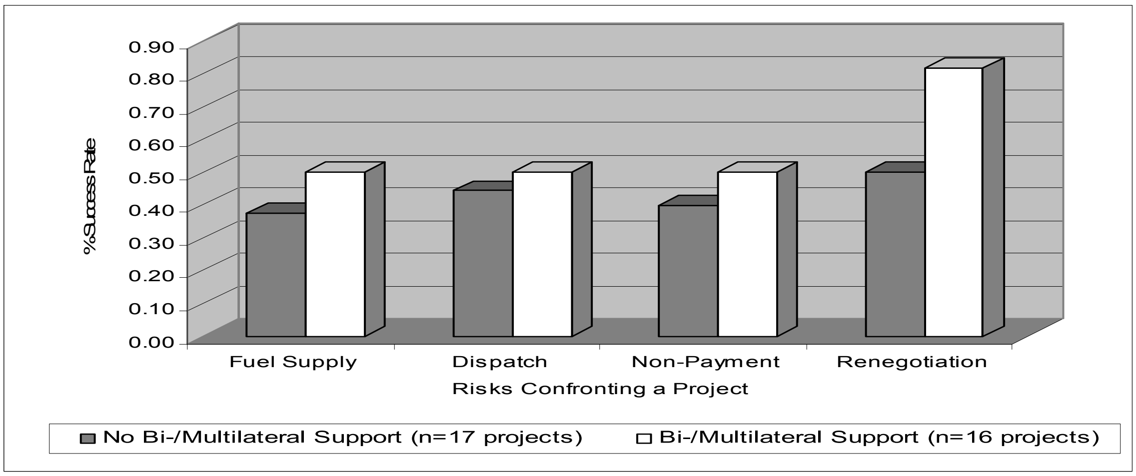

Figure 3 illustrates the basic argument with respect to multi- and bilateral partners—the risk mitigating effects of these partnerships appear to be significant in limited circumstances, such as in managing renegotiations, where their connections and influence may facilitate a cooperative resolution. Where conflicts become intense, as in threatened or actual non-payment, the myriad other concerns that these entities have begin to erode their willingness to exercise coercive force on host governments. Conversely, mundane operating risks, such as in protecting a reliable fuel supply, seem less well matched to the leverage of these partners (as would be expected for lending institutions). The bump in success rates in managing operational risks for projects with prominent international partners, this likely reflects the fact that many of these entities (particularly US Exim and the IFC) focus substantial attention on ensuring commercial viability in projects they lend to, meaning that dispatch and fuel risk is managed in advance.

The complicated picture presented by Figure 3 likely reflects two primary factors. First, multilateral and foreign government agencies are almost always lenders or guarantors of projects—rarely do they hold significant equity interests (equity shares above 5% are extremely rare). Thus, their self-interest is limited to protecting their own debt service or to extreme events that might trigger application of a loan guarantee to another lender. In the IPP universe, both payment default on loans and events triggering a guarantee have been quite rare (outside of the well-known cases in Indonesia, Pakistan

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that a reversal of government decision or action has taken place; and second, they are often afraid to undermine the government's credibility and their country's image of being an attractive investment site.").

and India). Second, multi- and bi-lateral organizations are not entirely free to use their influence because they must be attentive to their other relationships. Multilateral banks must sustain their broader relationship with a host government. Foreign export credit agencies (ECAs) are primarily interested in facilitating the business of their home country exporters, which are not always identical to serving the equity holders in a project that has already paid exporters and contractors; equipment suppliers are usually paid more quickly, and exit with their profit intact.

Two final categories of "prominent victim" represent somewhat distinct profiles: political risk insurers, and international commercial banks. Political risk insurance has been a prominent aspect of risk engineering in large infrastructure deals, both for the benefits of direct insurance coverage and from the perceived value of an endorsement from many of the insurers, particularly the Overseas Private Investment Corporation ("OPIC") and the Multilateral Investment Guarantee Agency ("MIGA"). By several accounts, the political risk insurance industry was slow to adapt to the challenges of the 1990s. Investors purchased available coverage for expropriation, political violence and currency inconvertibility only to find that their protection did not extend to the most important challenges of infrastructure investment in the 1990s, including government breach of contract that falls short of outright repudiation, regulatory changes that undermine the profitability of a project, and currency devaluation.[182] Subsequent innovations have begun to bridge the gap. While a strict breach of contract coverage is not available, coverage for arbitral award default is available. Currency devaluation coverage has also matured—OPIC offered a devaluation policy for AES's investment in the Tiete hydroelectric complex in Brazil, which played a part in the project bonds piercing Brazil's sovereign credit ceiling.[183]

Political risk insurance has played a limited role in the IPP experience. MIGA has paid out one claim (in Indonesia) out of the thirty-five power projects on which it has issued policies; OPIC has paid out two claims (in India and in Indonesia). None of the projects examined in this paper reports reliance (successful or otherwise) on insurance as a significant factor in explaining its project outcomes,[184] which probably reflects the limitations in coverage (outlined above) and the limited political clout of the insurers in helping to handle most of the problems that have the largest effect on projects; political risk insurers are unlikely to be roused to action by problems in managing fuel supply,

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[182] Kenneth W. Hansen, *Tales from the Dark Side: Lessons Learned from Troubled Investments*, *in* INTERNATIONAL POLITICAL RISK MANAGEMENT: LOOKING TO THE FUTURE 12, 13 (Theodore H. Moran & Gerald T. West, eds., 2005) (discussing the mismatch between supply and demand sides in the political risk insurance market during the 1990s); *and* Frederick E. Jenney, *The Future of Political Risk Insurance in International Project Finance: Clarifying the Role of Expropriation Coverage*, *in* INTERNATIONAL POLITICAL RISK MANAGEMENT: LOOKING TO THE FUTURE 103–115.

[183] Moody's Investors Service: Global Credit Research, AES Tiete Certificates Grantor Trust US$30 Million Certificates Due 2015, Pre-Sale Report (April 2001); Fitch Ratings, AES Tiete Certificates Grantor Trust, Preclosing Report (April 2001).

[184] This conclusion may also reflect a potential bias in evaluating projects—investment that ends in an insurance claim, given the fact that coverage is primarily for bare expropriation or political violence, would likely be rated poorly for either investors or hosts (or both).

resolving cost disputes, resisting the imposition of new taxes, or any of the other manifestations of so-called creeping expropriation.

Instead of the political clout of partners, the capital structure—in particular, the debt floor—does appear to be an important in determining how far government officials will allow the actual stream of payments to a project deviate from the terms of the original contract.[185] Investors have been correct in their expectation that the involvement of financial institutions (particularly large international banks, but including the multilateral development banks insofar as they also operate as lenders) deters host governments from squeezing the IPPs opportunistically to a level that would affect debt coverage.[186] Indeed, every government official interviewed for this study identified debt payments as a lower limit for renegotiations.[187] Even in cases such as in Tamil Nadu—where the government has reduced payments dramatically—*ad hoc* payments to cover debt service requirements are reportedly commonplace. After the closure of the Dabhol power plant, litigation brought by syndicated international bank lenders was largely settled, while the claims of equity investors are still fiercely resisted.[188]

In each of these cases—prominent international actors as lenders or guarantors, political risk insurance, or commercial banks—the IPP experience reveals little evidence of magic partners or arrangements that mitigate political risk to equity investors in any systematic way. Anecdotal evidence abounds, and the halo effect that such prominent partners carry is likely effective in some cases. Yet, projects—in particular, the equity portion of investment—remains exposed without the use of other risk management tools.

(d) Arbitration and Dispute Resolution

Project participants sought to contract out of host country legal risk by moving dispute resolution offshore, to a variety of international commercial arbitration panels.

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[185] This theme is a familiar one in the foreign direct investment literature. *See, e.g.*, Louis T. Wells and Eric S. Gleason, *Is Foreign Infrastructure Investment Still Risky?,* HARVARD BUSINESS REVIEW, Sept/Oct. 1995 ("The history of nationalizations suggests that in a crisis, debt obligations are more likely to be honored than equity obligations. This seems to be true even if the debt of held by the same parties that own the equity.")

[186] *See, e.g.*, THEODORE MORAN, *Lessons in the Management of International Political Risk from the Natural Resource and Private Infrastructure Sectors*, *in* MANAGING INTERNATIONAL POLITICAL RISK 70, 78 (Theodore H. Moran, ed., 1998).

[187] In addition, although not interviewed as part of this study, the Turkish Energy Minister in commenting on the ongoing dispute with BOT projects in that country said, "[w]hile negotiating with a single BOT power plant, you notice that they have twenty lenders. You may persuade one of them, but another just can't be persuaded. If you attempt to push a little harder on the issue, you say good-bye to foreign investors."), Radikal Daily, Nov. 11, 2004.

[188] A decade after the dispute first erupted and years after arbitration was first attempted, one of Dabhol's equity shareholders recently won an award in a proceeding against the state of Maharashtra before the International Chamber of Commerce's International Court of Arbitration. *See* Arbitration Tribunal Rules for Bechtel in India's Dabhol Power Project, May 3, 2005, *available at* http://www.bechtel.com/newsarticles/456.asp. A parallel proceeding against the government of India was settled by the parties in July 2005.

Recourse to these venues is provided either in bilateral investment treaties between countries that aim to protect the interests of investors or in the contract itself (and sometimes both). At this writing the value of international commercial arbitration remains a debated topic. Most decisions have been favorable to investors, awards have often been reduced, enforcement is uncertain, and the process of pursuing a claim to completion is costly and time consuming.[189] Additionally, value of the alternative—litigating in local courts—is also unclear. In the thirty-three projects in Table 4, three of the four projects that have been involved in arbitration have also pursued litigation in local courts; in three of these cases results have been favorable to the investors.[190]

To a significant extent, the difficulties in applying provisions for arbitration and dispute resolution reflect the fact that the body of law governing investment and contracting with sovereign counterparties is fragmented between national and international sources of legal authority. These issues are familiar territory in the literature on infrastructure investment. In the IPP experience, arbitral decisions have been challenged, overruled, diluted, or found inapplicable by national courts in India, Pakistan, Indonesia, and Argentina.[191] Often the grounds for these decisions were rooted in national laws holding that contractual terms could not be removed from the jurisdiction

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[189] For a broad discussion of these problems, see Frederick E. Jenney, *Breach of Contract Coverage in Infrastructure Projects: Can Investors Afford to Wait for International Arbitration?*, *in* INTERNATIONAL POLITICAL RISK: EXPLORING NEW FRONTIERS 45 (Theodore H. Moran ed., 2001); Mark Kantor, *International Project Finance and Arbitration with Public Sector Entities: When is Arbitrability a Fiction?*, 24 FORDHAM INT'L L. J. 1122 (2001). In each of four most high profile IPP arbitration cases—Dabhol Power Company in India, Hub River Company in Pakistan, CalEnergy's Dieng and Patuha projects in Indonesia, and Florida Light & Power's Karaha Bodas projects in Indonesia—arbitration has faced obstacles raised by local court injunctions and refusal's by host government authorities to pay awards. Dabhol's arbitration was held up for years by local court injunctions that compelled project proponents to desist from pursuing relief before arbitration panels. CalEnergy, in the Dieng and Patuha projects, first obtained an award from their Indonesian offtaker, PLN, for over $500 million. Upon non-payment by PLN, CalEnergy pursued another arbitration against the government of Indonesia, winning a slightly higher amount. Following non-payment by Indonesia, CalEnergy filed suit against OPIC and several private political risk insurers under political risk insurance policies (the insurers contended that the policies did not apply), eventually obtaining payment for the full amount of those policies, $290 million. *See* Julie A. Martin, *OPIC Modified Expropriatoin Coverage Case Study: MidAmerican's Projects in Indonesia—Dieng and Patuha*, *in* INTERNATIONAL POLITICAL RISK: EXPLORING NEW FRONTIERS 59, 60–61 (Theodore H. Moran ed., 2001). El Paso Corporation is caught in a particularly bewildering situation regarding two of its projects in Brazil. In one case involving El Paso's Araucaria project, protracted non-payment by state-utility Copel under the PPA led to an attempt at arbitration, however, the arbitration provision of the PPA has since been invalidated by a local court. At the same time, in the other case involving El Paso's Macaé project, the arbitration claim was filed by state counterparty Petrobras seeking recission of the participation agreement. El Paso Corporation, Form 10-K (2005) at 143-144.

[190] The four projects are: Macaé (Brazil), Termoceara (Brazil), PPN Power (India), Casecnan (Philippines). Of these, only Casecnan has not been involved in local court litigation (most likely this reflects the fact that Casecnan's dispute with NPC and NIA was settled prior to a full adjudication). The Brazilian projects have won favorable decisions in Brazilian court; PPN Power in India remains entangled in litigating a shareholder dispute between United States sponsors and local/Japanese sponsors.

[191] For one infamous case see Hub Power Co. Ltd. v. Pakistan WAPDA, Federation of Pakistan, Civil Appeal No. 1398 and 1399, Pakistan Sup. (Supreme Court of Pakistan, 14 June 2000), *reported in* Mealey's International Arbitration Report, Vol. 15, #7, July 2000.

of regulators to that of arbitration, or that the formation of the contract (including the arbitration clause) was itself fraudulent or contrary to public policy. Arbitral decisions favorable to investors, upheld after years of litigation as in the ongoing Dabhol disputes, they are often not enforceable under national law against the assets of the host contractual counterparty. In these cases, judgments can be collected only against defendants with assets offshore. In practice, arbitration has not provided a cost- and time-effective ring of defense.

Less well-recognized are deep disagreements on the substance of the law that applies to investment disputes. In the absence of an investment agreement within the WTO or similar organization, the substantive law governing investment disputes remains an unsettled collection of principles that are borrowed from a variety of sources. This problem manifests in countless ways.[192] In the IPP experience, it is seen most clearly in arbitrations concerning government attempts to void or alter contracts in the aftermath of macroeconomic shock—most of which turn on some variant of the claim that the dramatic change in circumstances (economic force majeure) provide a defense to strict enforcement of the contract.

The substantive law applicable to claims that seek relief for changed circumstances are reflected in a variety of sources of international and municipal law. Nonetheless, some basic elements remain constant; as a general rule, the party advancing a claim of hardship or changed circumstance must not have been able to foresee the events in question at the time of contracting, the events must be beyond their control, and they must not have assumed the risk of the events happening in the contract.[193] However, the exact meaning of these terms is far from settled. In a formal sense, the allocation of a risk to a contract party would preclude their claim that the occurrence of that risk provides grounds for a claim of hardship or changed circumstances, because they assumed that risk in the contract. Notably, in the case of macroeconomic shock, however, this is a slippery concept which fits only uncomfortably in the existing landscape for foreign direct investment. For example, in past arbitrations, assumption of the risk of currency devaluation has been implied, absent explicit provision, from the fact that the contract was denominated in US dollars.[194] However, in the absence of explicit

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[192] *See, e.g.*, Susan Rose-Ackerman & Jim Rossi, *Disentangling Deregulatory Takings*, 86 VA. L. REV. 1435 (2000) (discussing the challenges, in both the United States and in developing countries, of dealing with the problem of stranded costs that result when regulatory regimes change dramatically); Dinesh D. Banani, *Note: International Arbitration and Project Finance in Developing Countries: Blurring the Public/Private Distinction*, 26 B.C. INT'L & COMP. L. REV. 355 (reviewing the justifications for international arbitration as recourse for infrastructure projects and the uncomfortable meeting point of legal theory and practice in a series of cases involving IPPs).

[193] This formulation draws from The International Institute for the Unification of Private Law (UNIDROIT), UNIDROIT Principles of International Commercial Contracts, Art. 6.2 (2004). The author thanks Jeff Rector for providing this example.

[194] Final award of 4 May 1999, Himpurna California Energy Ltd. (Bermuda) v. PT (Persero) Perusahaan Listruik Negara (Indonesia), 14 Mealey's International Arbitration Reports, A1–A58, at ¶ 194 ("In the [power purchase agreement] … by pricing in US dollars rather than in Indonesian rupiah, the Parties unambiguously allocated the risk of a depreciation of the local currency to PLN.").

risk assumption, the increasing (and explicit) recognition that developing countries cannot be expected to bear the costs of massive devaluation that affects private infrastructure sectors[195] suggests that, in practice, the full risk is not actually allocated even when contracts are denominated in an offshore currency. Thus far, bad cases have made bad law—the Indonesian claims were simpler because PLN had not negotiated in good faith with its IPPs, precluding a full adjudication of the implications of risk allocation and implied assumption of the risk.[196]

In the end, arbitration proceedings do not explain variation in outcomes in any helpful way. By the time arbitration has been pursued to completion, one, if not both, parties will have evaluated the IPP poorly. Arbitration does serve an important role as an ultimate deterrent to unacceptable adjustments in contracts, although in most matters it is very difficult to measure the exact value of a strong deterrent since, by definition, a successful threat leaves no evidence of action. The triggering of arbitration is most likely the endgame signal of investors who, often, are completely abandoning the IPP field as foreign investors. Conversely, it is unlikely that future investors will sink capital with sustainable returns in countries with long histories of arbitrations, even if those arbitrations have ultimately favored investors.

2. *Strategic Management: Reducing Risks with Project Planning and Design*.

The factors that operate at the level of countries define the context that can lead to stress on projects. Investors and host governments anticipated those stresses and sought to engineer them through a series of measures built into long-term contracts, their partnerships, and provisions for enforcement and dispute resolution. Those measures are necessary conditions that array rings of defense around the financial and operational terms of the project. However, these arrangements are not sufficient in themselves. In changing circumstances, the contracts usually do not hold, and many of the stresses are difficult to engineer completely. A broad category of project factors—"strategic management"—plays a large role in explaining final project outcomes. Unlike attempts to account for risk by engineering prices and contracts *ex ante*, these "strategic risk management" practices assume that instability is inevitable, and seek to structure the project in manner that reduces vulnerability to particular risks.

IPPs have little recourse to self-help measures that allow them to escape their dependence on government decisions. In worst case scenarios, plant investors have exit options—including the removal of complex software and equipment that, in some cases,

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[195] This is likely the most prominent lesson from the past round of investment. *See, e.g.*, Moore, *Allocating Foreseeable Sovereign Risks*, *supra* note 20, at 480 ("Acordingly, the risk of currency devaluation, while typically allocated to the state utility company rather than the IPP, cannot be isolated from the project entity itself, The greater the extent of currency mismatch … the more likely the state entity … [is] to unilaterally alter the payment schedule, request a renegotiation of the PPA, or renege on their contractual payment obligations. Thus, even where currency risk is allocated to the state utility company, IPPs remain vulnerable to the consequences of currency devaluations.").

[196] Final award of 4 May 1999, Himpurna California Energy Ltd. (Bermuda) v. PT (Persero) Perusahaan Listruik Negara (Indonesia), 14 Mealey's International Arbitration Reports, A1–A58, at ¶ 190.

render the plant useless—but these nuclear options are costly especially to the investor. Thus management of conflicts plays a large role in IPP investments; the property rights of the IPP, which require the consent of the government and the offtaker to achieve their fullest value, rest on the ability of project operators to keep costs down, to navigate foreign business environments (particularly in turbulent times), and to respond to changing circumstances with flexibility. Looking across projects it seems that IPP operators and their government counterparties vary in their ability to manage a large and complex infrastructure project in unfamiliar and unstable environments;[197] in particular, when projects face political pressure to alter the terms of the original deal or other stresses befall a project, there is wide variation in the effect on outcomes.[198]

This dimension of risk management has been proposed by a range of analysts, yet never fully populated.[199] The IPP experience offers a range of practices that fit this description and are systematically related to successful projects; this section focuses on five factors. The first is the mundane but important issue of costs. Regardless of contract terms, cost-competitive projects that have been selected in a transparent bidding process are much less likely to suffer adverse renegotiations than those that deviate widely from the norm. Second, management of counter-party risk, particularly during politically sensitive periods that require adjusting contracts, is essential to preserving a successful outcome. Third, a host of factors that can be bundled together under the umbrella of "commercial management" underscore the need for IPP investors to perform their own calculations about whether the host will need IPP power (since government projections are often wrong) while also managing their projects for flexibility in changing circumstances. Fourth, successful IPPs require care in their strategy for engaging local partners. Local partners do not have much impact on strategic issues surrounding the project, such as whether contracts are enforced; rather, local partners can lead to much better operational performance due to their ability to manage fuel supply, ensure dispatch of the plant and affect other decisions that determine the plant's day-to-day operations. Fifth, active management of the broader relationship with project stakeholders—a category of relationships that has expanded with democratization of many societies—

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[197] *See, e.g.*, Henisz & Zelner, *supra* note 86, at 154 ("Although insurers often treat political risk as a country-specific phenomenon, substantial variation in the probability and magnitude of loss exists at the firm level. Individual firms confront different sources of policy uncertainty and political influence, depending on their familiarity with the local environment, nationality, network of global stakeholders, partner status, size, and technological leadership. Sophisticated managers address political risk by employing tailored risk mitigation strategies to reflect specific factors affecting a firm's risk profile.").

[198] This point is often obvious to project managers in interviews, yet has not found equal acceptance in the academic literature. There is greater acceptance of the need to consider such challenges as part of the inevitable landscape for large infrastructure projects. *See* ROGER MILLER & DONALD LESSARD, *Public Goods and Private Strategies*, *in* THE STRATEGIC MANAGEMENT OF LARGE ENGINEERING PROJECTS: SHAPING INSTITUTIONS, RISKS, AND GOVERNANCE at 19-50, 22 (2000) (estimating that in a sample of sixty large engineering projects, including thirty-two power plants, each project encountered an average of five unexpected problems—in addition to problems that were expected).

[199] *See* references notes 153–54 *supra*; *and see also* Witold J. Henisz and Bennet A. Zelner, *Managing Political Risk in Infrastructure Investment*, unpublished working paper available at http://www-management.wharton.upenn.edu/henisz/.

leads to IPPs that are more sustainable. In all five of these dimensions, IPP investors and government hosts alike have leverage.

(a) Ensuring Competitiveness: Bidding and Cost Management

Looking across countries and projects, it is clear that investors and government decision-makers have substantial leverage over the performance of the projects that get built. Key decisions lie at the beginning—with project selection. This study generally confirms the wisdom that selection through competitive bidding is the best mechanism. The benefits of relying on competitive bidding including low prices for power[200] and increased transparency[201] that bolster the sustainability of projects. Indeed, countries that have been successful in creating highly competitive bidding processes have achieved prices among the lowest in the world. Prices in both Mexico and Egypt, expressed in dollars but indexed to local currency exchange rates, reach as low as 2.4 cents/kWh.[202] Prices in Thailand, expressed in baht and converted to dollars, are approximately 4.3-4.8 cents/kWh.[203] In Turkey, the prices for the second round (competitively bid) projects were 60% lower than the first-round negotiated projects, according to some reports.[204]

However, in practice bidding has not always led to lower prices[205] or greater sustainability; nor has it always succeed in attracting bids. Much of the variation in bidding outcomes reflects factors that are already widely known to play a significant role in auctions. Notably, auctions vary widely in the number of firms competing.[206] Timing also plays a role,[207] along with fluctuations in market prices for crucial inputs (e.g., concrete, engineering services and steel); a host of pre-existing legal and regulatory

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[200] Yves Albouy & Reda Bousba, The Impact of IPPs in Developing Countries—Out of the Crisis and Into the Future, Public Policy for the Private Sector Note No. 162, The World Bank (Dec. 1998), at 6.

[201] Michael Klein, *Infrastructure Concessions—To Auction or Not to Auction?*, World Bank Viewpoint Note No. 159 (1998), at 2–3.

[202] Prices in Egypt refer to the Sidi Krir natural gas-fired project, *see* Eberhard & Gratwick, *supra* note 77, at 12. Prices in Mexico refer to Iberdrola's Monterrey III natural gas-fired project, *see* InfoCRE, Julio-Agosto 1999 Año 2, No. 4 available at http://www.cre.gob.mx/publica/infoCRE/infocre070899.pdf.

[203] Thai officials at the National Energy Planning Office ("NEPO", now the Energy Policy & Planning Office, "EPPO") evaluated project bids on the basis of levelized unit prices ("LUP". These figures refer to LUP's normalized for a commercial operations date of 2005.

[204] Venkataraman Krishnaswamy and Gary Stuggins, *Private Sector Participation in the Power Sector in Europe and Central Asia: Lessons from the Last Decade*, World Bank Working Paper No. 8 (2003) at 105. This figure, reported in the World Bank document above, was repeated by industry participants in interviews.

[205] Albouy & Bousba, *supra* note 200, at 6 ("Bidding seems to have reduced PPA prices by 25 percentage points on average, but exceptions are numerous and important.")

[206] This ranges from Thailand, with 50 bidders and 88 bids in the 1994 solicitation for only seven projects, Egypt, with 50 firms involved in the Sidi Krir tender, and Mexico, with 48 bids for the first 8 projects, to Malaysia, in which projects were allocated to further the bumiputra economic policy, the Philippines, where two firms faced off for the Pagbilao project, and Kenya, where three firms bid for Tsavo.

[207] *See* DELOITTE TOUCHE, SUSTAINABLE POWER SECTOR REFORM, *supra* note 1, at Figure 2-10.

issues can affect how investors are willing to bid.[208] This has led, in part, to decisions by governments to abandon competitive bidding. While this is at times necessary, where projects are not selected through bidding governments and investors engage in direct negotiations that often create incentives to select projects that prove costly. In India, the issue generating the most consistent controversy in the IPP sector is costs and cost overruns for early projects that were selected through negotiations rather than bidding, with tariffs set according to a cost-plus system. Such pricing systems often lead to projects with excessive capital expenditures.[209] Moreover, such negotiations suffer from informational asymmetries and mixed incentives. Direct negotiation intrinsically suffers from low levels of transparency, which left these early Indian projects exposed to the criticism that costs were inflated because these projects were allocated to firms with special connections and over-priced expertise rather than through market discipline.[210] In China, provincial and national government officials often negotiated PPAs in the early 1990s with little regard to their cost;[211] the cost of these more expensive plants was structurally unsustainable when changed circumstances (notably the onset of the 1998 power glut), created stress on private investors. While there are examples of negotiated deals that have been stable—many of the early Philippine and Kenyan projects, for example—the political heat surrounding these deals has been intense, and outcomes easily could have been worse.[212]

Nonetheless, looking at a timeline of successful IPPs solicitations, it appears that absent hard impediments (such as Turkey's constitution), competitive bidding is possible in a variety of circumstances. Argentina in 1992, Thailand in 1994, Egypt in 1996-98,

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[208] In Brazil, potential investors in thermal projects were wary of accepting take-or-pay contracts for gas supply when they were not confident that they could match those fuel commitments with power sales. This, and a host of other issues, stalled investment in such plants. Dymond, Christopher and Ilse Pineda, *Brazilian Power Project Finance*, 7 J. OF PROJ. FIN. 29 (2001). In Turkey, the Constitution required any public service concession to be regulated by public administrative law, which was a slow, confusing and discretion-laden regime that discouraged investment. Turkish authorities made several attempts to bypass this requirement, including a ministerial decree that allowed the first BOT program in the face of an electricity crisis. Eventually, the Turkish parliament had to amend the Constitution in order to craft a durable solution. *See* sources in note 117, *supra*.

[209] This is the well-known Averch-Johnson effect that has been observed in regulated utilities in the United States and elsewhere. H. Averch & L.L. Johnshon, *Behavior of the Firm Under Regulatory Constraints,* AM. ECON. REV., v. 52, December 1962, at 1053–1069.

[210] For example, suspicion of cost padding the EPC contracts for early "fast-track" projects was a common complaint among industry participants in India. These suspicions were not allayed when the problems in the Spectrum Power project became public with the indictment of the local partner for fraud and mismanagement of the contract with AP Transco.

[211] Woo, *supra* note 80. In the early development of the IPP program in China, tariffs were set according to a generous cost-plus rate regime, which provides no incentive for cost or efficiency improvements, instead setting tariffs to provide a given return based on actual costs … whatever they are. *Id.*; *and see also* Klein, *Bidding piece…*

[212] At the extreme, there is, of course, Indonesia, that essentially allocated projects to companies able to accept "local" partners—usually members or associates of the Suharto family. *See See* LOUIS T. WELLS AND RAFIQ AHMED, [MAKING FOREIGN INVESTMENT SAFE: PROPERTY RIGHTS AND THE PRIVATIZATION OF INDONESIAN INFRASTRUCTURE], ch. 16 (*forthcoming*, 2005).

and Mexico and Turkey in 1997–98 have all attracted interest sufficient to achieve low and sustainable prices (leaving aside, for the moment, the troublesome issue of currency risk).[213]

There is, of course, more to the story. The most successful bidding experiences involved rules that ratcheted down prices and created an incentive for project sponsors to keep costs under control throughout the process from the first round of bidding through financial closure. Thailand created a multi-stage bidding process that was very effective in this respect. First, the bidding was aggregated, so that firms bid into a pool from which a number of projects would be selected—rather than soliciting bids for a specific project. Thus, a large number of bidders competed against each other (50 bidders and 80 bids). From the first round, a shortlist was announced in late 1995, ranked by tariff; sponsors with the best positions on the list had an invitation to continue negotiating a PPA, during which project particulars would be settled. The first IPP to settle on contract terms, Independent Power, had also submitted the lowest tariff bid in the auction. The Independent Power PPA set a blueprint for the sector, particularly by reaching agreement with EGAT (the offtaker) and PTT (the gas supplier). Subsequently, EGAT worked down the auction short list to negotiate terms with additional projects. These projects were often asked to lower their tariff below what had been bid at the auction, using the Independent Power PPA as a benchmark; if EGAT and the sponsor could not agree on terms, a long queue of rivals stood ready to enter the room.

The original terms of the bidding required that no more than 80% of the net present value of project revenues be recovered during the first 75% of the contract term. This requirement, which led to tariffs that were back ended relative to those in most other emerging markets, reflected the country's effort to encourage long-term commitments, and did lead to an incentive structure that had a much longer time horizon than in many other countries where IPPs pushed for heavy front-loading so they could recover costs quickly.[214] However, the rise in the back end of the tariff was lopped off in negotiations with EGAT, because the front-end was already so low that lenders would not allow further reductions that might erode debt service coverage. Such changes reveal just one of the many complexities that require individualized project negotiations, and the challenge for governments who want to design a competitive auction (which, by design, should encourage competition among many players over relatively simple commodified terms) and the fact that IPPs are ultimately highly particular.

(b) Managing Counterparty Risk

The risk of counterparty non-performance is a central concern for investors in IPPs, particularly those selling to a single off-taker. Careful selection of counterparties

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[213] One potentially helpful, though flawed, indicator of the variation in general risk levels among these cases is the International Country Risk Guide Composite Score during each auction. For these episodes, the ICRG ranges from 52.3 (Turkey in 1998) to 75 (Thailand in 1994), with most falling in the mid- to low 60s.

[214] Selected interviews with project sponsors in Thailand, May 4–7, 2005.

for IPPs not only ensures creditworthiness, but it also may ease the task of managing the political pressure that inevitably builds up around complex reforms. In practice, IPPs find themselves constrained in their freedom to work with offtakers. Most countries have just one state-owned offtaker (the so-called "single buyer" system). A few have multiple distinct offtakers—typically distributed in different parts of the country, often in countries that are federal in many other aspects of governance. It might appear that a choice of offtakers would give the IPP leverage to choose the more suitable partner. In fact, this study suggests the opposite. Numerous collective action problems arise when many subnational actors are involved. By contrast, the existence of a single offtaker allows reformers to focus their leverage on a single point; it also concentrates concern regarding the effects of IPP relationships for the country's reputation as a site for investment.

Countries that have vested a central authority with control over the relationship with private generators generally have been more able to manage most stresses that arise for IPPs—provided that the stress is not so severe that it jeopardizes the entire solvency of the power sector. Thus, in single buyer countries such as in Malaysia, Thailand, the Philippines, Egypt, Mexico and Turkey, IPPs were able to weather various challenges and often managed the hardship of financial crisis without abrogating contracts. The superiority of a central counterparty reflects three factors at work. First, stresses have been more likely to be resolved when critical counterparties are under the control or influence of reformers in the central government. Second, central counterparties have had greater concern for the nation's reputation along with a long-term interest in sustaining private investment. This is an unmistakable element in the resolution of the Asian financial crisis in Thailand and the Philippines. Third, central counterparties have had access to the resources and strategic vision that allow them to devise fair and sustainable cost-sharing arrangements that arise, for example, during contract renegotiations following a macroeconomic shock.

In Thailand, renegotiations of the IPP projects began after July 1997 when the government elected to float the baht, which quickly shed half its pre-crisis value before recovering marginally over the next year. Thailand's PPAs were denominated in baht, while the investments were financed in hard currencies; even if EGAT honored the contracts, the private investors would be badly hit by the currency depreciation. In the end, EGAT assumed a large share of the costs of the currency depreciation by indexing part of the capacity payments to a fixed exchange rate (27 baht per dollar) that was similar to the pre-crisis level.[215]

One version of the negotiations behind this decision points to a change in law clause in the PPAs. Prior to the crisis, the baht had been pegged to a basket of currencies, and had remained stable at 25 baht to 1 US dollar for years. The post-crisis floatation, as opposed to a straight devaluation, thus arguably constituted a change in law that, if

[215] The fixed rate of 27 baht per dollar was close to the precrisis rate of about 25 baht per dollar, despite the fact that in early June 1997, just prior to when the renegotiation was conceived, the baht traded at 40-42 per dollar. R. David Gray and John Schuster, The East Asian Financial Crisis—Fallout for Private Power Projects, Viewpoint Note No. 146, The World Bank (1998).

applied automatically, would have required the Thai government to make whole any loss stemming from the change.[216] This interpretation was not assured, however. At the time of the crisis, the basic terms of the PPAs had been agreed, but the final contracts had not yet been signed; litigation based on the change in law clause would have been difficult for the IPPs. Industry participants recall that actual discussion of how far this clause would apply faced resistance from EGAT until government officials stepped in to mediate a solution.[217] Further, the assumption of liability for the currency depreciation by EGAT roughly approximated the actual costs that gas- and coal-fired power plants in Thailand would incur in hard currency,[218] thus virtually eliminating such liability from the IPPs—a policy that could have been far less generous and still preserved the IPP program in some form.[219]

The resolution of the crisis within the Thai IPP sector reflects a range of factors discussed earlier in the paper, including the fact that none of the plants was online at the time, strong cost recovery by EGAT, and the transparent and competitive solicitation that led to low prices and broad legitimacy. Nonetheless, without additional government support, the IPP program would have largely evaporated (with the exception of Independent Power—which had secured financing prior to the crisis and had covered the currency liability with forward hedges. Nonetheless, this support faced resistance from within EGAT, and the eventual solution was driven largely by the insistence of reformers within government planning offices at the time.[220]

The Philippines conducted a well-publicized renegotiation of its IPP contracts in 2001. Political pressure was high because retail prices were rising rapidly as the currency declined in value, large amounts of new IPP capacity were due to come online, and Congress had conducted a review of the state utility's IPP obligations (itself due to public outrage as higher IPP costs from the declining currency were passed to consumers in a way that was highly visible on every user's electricity bill). These renegotiations succeeded in generating savings for the government and in maintaining the confidence of IPP investors in the country. Concessions were obtained, with some pressure,[221] from

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[216] National Energy Policy Office, Privatisation and Liberalisation of the Energy Sector in Thailand (1999) [note the National Energy Policy Office, or NEPO, is now the Energy Policy & Planning Office, or EPPO].

[217] Selected interviews with power industry investors and project advisors, Bangkok, Thailand, May 4–8, 2005.

[218] An example of the equation used to calculate the FX cover for the availability payment for gas-fired IPPs is: $APR_{1\ adjusted} = [.90 \times APR_{1\ unadjusted} \times (FXM/27)] + [.10 \times APR_{1\ unadjusted}]$.

[219] It is difficult to determine precisely where leverage lay in this process. The Thai government, while only loosely constrained in a legal sense, was under pressure to preserve an important and extremely high profile investment program. The IPP investors, while of course free to simply not sign PPAs unless the government provided satisfactory adjustments, had already sunk millions of dollars into their projects.

[220] This account reflects interviews with industry participants in Bangkok, including officials from EGAT, EPPO, and several IPPs, and echoes a similar account in Chuenchom Sangarasri Greacen and Chris Greacen, *Thailand's Electricity Reforms: Privatization of Benefits and Socialization of Costs and Risks*, PAC. AFF., Vol. 77, No. 3 (Fall 2004).

[221] Comments by former Secretary of Energy Vicente Perez at "The Experience of Independent Power Projects in Developing Countries" Seminar held at Stanford University, June 2-3, 2005.

companies that agreed to provide them; often, agreements reflected a give-and-take between government and power company.

The process began with a 2001 electricity sector reform law ("EPIRA") that required the appointment of an inter-agency commission ("IAC") to review the IPP contracts, which by 2001 had become politically and economically vulnerable. The law also mandated the unbundling of electricity rates in consumer bills.[222] This seemingly innocuous measure allowed Filipino citizens to see for the first time the precise origins of the costs that created some of the highest electricity rates in Asia. What they saw was that the power purchase adjustment that financed the state utility's IPP obligations was almost equal to the cost of the actual electricity consumed.[223] Unlike many other countries facing macroeconomic shock, which benefited from a series of factors that ameliorated the impact of crisis on the IPP sector,[224] the Philippines enjoyed no such buffer. IPP payments were denominated in hard currency, in 1997 already 3000 megawatts were online, with an additional 2000 megawatts to enter service by 2001. Further, the allocation of projects, particularly the early "fast track" projects designed to address the severe electricity crisis of 1992-93, had not been transparent or competitive. That context put a shadow over the entire sector; public outcry over corruption and incompetence mounted as Napocor's payments to IPPs grew.[225]

The IAC was composed of representatives of the Department of Justice, the Department of Finance, and the National Economic Development Agency. There were no electric power industry government officials involved in the process (nor any representatives from the project companies), although the IAC did employ consultants to understand the complex contracts. The EPIRA law required the IAC to review the IPP contracts for provisions that were "grossly disadvantageous, or onerous, to the Government."[226] The committee eventually produced a report ("IAC Review") that roughly reflected this scope. The IAC Review covered a total of 35 projects—all of Napocor's operating contracts with IPPs. Of these, six were cleared, and the other 29 contracts were found to have issues of various kinds and were targeted for renegotiation.

Upon completing the review, the IAC handed responsibility for implementing its findings to the Power Sector Assets and Liabilities Management Corporation ("PSALM"). PSALM, a state owned corporation that had been tasked with privatizing

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[222] Republic Act No. 9136, § 36 (Phil.)(2001).

[223] *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

[224] Thailand (transparent bidding, low prices, no IPPs online), Egypt (transparent bidding, low prices, low IPP capacity), Malaysia (all local currency inputs).

[225] In particular, see a series of reports by the Philippine Center for Investigative Journalism on the IPP experience in the Philippines. Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (5-8 August 2002); Luz Rimban and Sheila Samonte-Pescayo, *Trail of Power Mess Leads to Ramos*, Philippine Center for Investigative Journalism, Aug. 5-8, 2002.

[226] Republic Act No. 9136, § 68 (Phil.)(2001).

Napocor's assets, was staffed by electricity sector experts and former private sector bankers and lawyers. PSALM was mandated in the electricity reform law to implement the findings of the IAC Review and to "diligently seek to reduce stranded costs, if any."[227] At the same time, PSALM was called upon to "optimize the value and sale prices"[228] of Napocor's assets in the privatization process. The conflicting mandates to extract concessions from investors on the one hand, and to attract competitive bids from investors into the power market on the other hand, likely moderated PSALM's approach to the renegotiation process. [229]

PSALM announced the results of the IAC review in an all-hands meeting with the IPP companies. Investors initially greeted the renegotiation demand with trepidation,[230] particularly in light of still fresh controversies surrounding the IPP programs in Indonesia and Pakistan. The renegotiations began with a lengthy consultation process that eventually settled on two principal avenues. First, IPPs would bear cost or fee reductions that were not contrary to the terms of the original contract—most commonly the project companies made a collateral agreement not to nominate the full 105% or 110% that the contract allowed,[231] or clarified ambiguous terms in a manner advantageous to the government. Second, PSALM also considered a negotiated buy-out when the sponsor firms were interested in exiting the project—this eventually happened only in the case of ChevronTexaco's San Pascual project.[232] During the entire process the constraints

[227] Republic Act No. 9136, § 68 (Phil.)(2001).

[228] Republic Act No. 9136, § 51 (Phil.)(2001).

[229] For example, PSALM took steps to diffuse tension, beginning by reiterating that the Philippines would not violate duly executed contracts, and explained the somewhat mysterious rubric of the IAC Review findings. PSALM clarified that findings that contracts were "expensive" or "onerous" were not basis for legal action or unilateral renegotiation. Similarly, a finding of "legal issues" in a contract did not refer to defects in the validity of the contract, but rather to problems or disputes in interpretation or application of certain terms. As such, the much criticized "legal issues" were also not grounds for legal action.

[230] *See also, Philippine Government's IPP Contract Renegotiation Plans Under Scrutiny*, Electric Utility Week (Aug. 19, 2002) (discussing fears of IPPs and businessmen over looming renegotiation threat).

[231] A peculiar clause in many of the Philippine PPAs provided that an IPP could nominate up to 105-110% of the "contracted" capacity. This overnomination would provide the basis for calculating capacity payments to the IPP. Capacity payments are the primary source of revenue for projects with a standard two-part tariff—variable energy payments reflect primarily pass-though costs such as fuel and operations expenses. Thus, many IPPs in the Philippines had been earning additional returns from the 5-10% overnomination for several years. As discussed earlier in the case of Mirant, it seems that most sponsors and lenders had not calculated this amount in the original pro forma for the projects, so their elimination did not threaten debt service or expected equity returns.

[232] The San Pascual cogeneration facility was to be developed jointly by Chevron-Texaco and Edison Mission Energy. Project development was derailed by the Asian financial crisis, when lenders and insurers faced pressures of their own and began withdrawing capital from Asian markets. (In this sense, San Pascual faced similar challenges to those faced by the Thai IPPs, which were in the midst of development when the crisis struck and had to begin from scratch to secure financing). At the same time, Napocor found itself with excess power and in need of reducing its liability under IPP contracts. After some negotiation, the San Pascual contract was purchased back by the Philippines for US$6 million, against the consortium's claim for US$20 in development costs. This contract became a valuable asset for Napocor and PSALM—the EPIRA law had barred Napocor from signing new power purchase agreements, but the San Pascual contract was grandfathered in and could be used to sweeten the deal by accompanying some of Napocor's

imposed by lenders were perceived as prohibiting a unilateral change in terms by the government (once again illustrating that debt payments are the outer limit for expropriation); in addition, the importance of preserving the Philippines' reputation in international markets was explicitly emphasized.[233]

In seven cases (in addition to the original 6 cleared by Congress), PSALM decided that no action was required or possible. This outcome reveals that when government officials have the leverage and opportunity to examine in detail the finances and contractual basis for particular projects, contentious issues often evaporate. The process was managed under tight secrecy, which was essential to obtaining proper disclosure from the IPPs, and Philippine officials essentially announced only the savings generated by securing concessions from the IPPs. While the decision to limit transparency in a matter of public concern is questionable, in this case, the closed-door conduct of talks is often cited as contributing to a swift resolution.[234] The majority of the savings were generated from five companies – Mirant, Marubeni, Steag, ChevronTexaco, and CalEnergy. Mirant, and many companies afterwards, agreed to forego nomination of 105% of capacity as allowed in the original contract for the Pagbilao station; over the life of the contract, this 5% of capacity accounted for hundreds of millions of dollars in savings. It is hard to see that this process could have been orchestrated with such dexterity if authority over the power sector had been fragmented or if the Philippines had had a large number of offtakers beyond the political reach of central government reformers.

(The study treats the Philippines, largely, as a single buyer system; in reality, in addition to the main offtaker Napocor there are several other much smaller offtakers, including private power users, who figure in the story. Indeed, by comparing the centralized and subnational buyers the point here is strengthened. The larger "classic" IPPs signed agreements with the state utility Napocor (or Meralco, which though private is the dominant provider of distribution services in the country); these agreements were generally able to accommodate all the typical challenges in running an IPP, such as the enforcement of offtake arrangements or handling unreliable fuel supplies. More serious stresses on these contracts arose only in the context of the country's macroeconomic crisis. In contrast, projects that set PPAs with subnational entities such as the export-

generation assets that were up for sale. Jennee Grace U. Rubrico, *PSALM asks DoJ opinion on use of existing power contract for Sucat sale*, BusinessWorld Internet Edition (Jan. 7, 2004).

233 This description of PSALM's strategy has been adapted from a PSALM presentation to the House Energy Committee of the Philippine Congress, on May 7, 2003, and from conversations with industry participants in the Philippines in February 2005.

234 On the other hand, it has not escaped the notice of civil society in the Philippines. *See, e.g.*, Luz Rimban and Sheila Samonte-Pescayo, *Trail of Power Mess Leads to Ramos*, Philippine Center for Investigative Journalism, Aug. 5-8, 2002, *and* Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (5-8 August 2002), *both available at* http://www.pcij.org/stories/2002/ramos3.html.

processing zones[235] or smaller national firms such as the Philippine National Oil Company,[236] encountered more chronic problems.)

By contrast, the countries that have multiple buyers have seen much more variable experience. The Chinese and Indian political systems both delegate authority to central as well as state or provincial authorities. In some of these states and provinces there have been chronic and seemingly unsolvable problems of nonpayment because the incentives within the host governments often diverge just at the moments when critical decisions about IPPs are needed. In China, local authorities exploited annual tariff reviews to squeeze IPPs while protecting local plants—even as the central government feared the harm to the country's reputation for allowing this practice. In India, there are often blurred relationships between state and central government officials on matters of reviewing costs or allocating fuel. Projects in both countries found themselves defending terms they thought had been agreed previously, only to find that other levels of government (where the cost of complying with original agreements often falls) have frustrated the deal.

Both India and China have asserted a greater degree of central control on IPPs, motivated at least in part by these concerns. For example, IPPs in India are eager to secure classification as "mega" projects—which allows them to sell power to the Power Trading Corporation (PTC), a national government entity that controls power sales across state boundaries. Payment from the SEBs to PTC is supported with mandatory letters of credit and senior rights over central government funds to the states.[237] In China, IPPs struggled to operate in local environments where local actors enjoyed powerful advantages in securing dispatch for their plants.[238] Substantial changes in the late 1990s focused on taking the IPPs out of the protected local context, far from Beijing's oversight, and connecting them to larger regional grids, at least in part to remedy these problems. Thus, the offtaker for Shajiao C was changed from the Guangdong Electric Power Bureau to Yudean and Guangdian, entities that sell electricity to the regional South China Grid, and the offtaker for Shandong Zhonghua has been changed from the

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[235] These projects include Cavite and Magellan, which were developed by CMS Energy and by Edison Mission Energy, respectively, and acquired by Covanta Energy in the late 1990s. Each project is now essentially bankrupt, and have been singled out for particularly harsh criticism in the Philippines government review of IPP contracts. *See* Covanta Energy Corporation, Form 10-K (2005) at 23–24, *and see also* INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002).

[236] For example, one of the only arbitrations in the Philippines grew out of CalEnergy's two geothermal plants there, *see CalEnergy International and PNOC Energy Development Corp.*, Global Power Report (June 20, 2002). In the Philippines, the state maintains a monopoly over geothermal resources, so geothermal IPPs sign energy conversion agreements with PNOC, which owns and provides the steam and also purchases the electricity before on-selling to Napocor.

[237] *See, e.g.,* INTERNATIONAL ENERGY AGENCY, ELECTRICITY IN INDIA: PROVIDING POWER FOR THE MILLIONS (2002); Mark Riedy, *Project Finance India 2005: Overcoming Hurdles to Growth*, Andrews Kurth LLP Press Release (2005), *available at* http://akllp.com/Page.aspx?Doc_ID=2870.

[238] Woo, *supra* note 80, at 27.

Shandong Provincial Electricity Company to the China Guodian Group, a national generating company.[239]

In some settings, the selection among multiple buyers does explain variation in outcomes for projects. Facing a looming electricity crisis in the late 1990s, Brazil was in dire need of additional thermal generating capacity.[240] Thermal generating capacity is risky in Brazil for a variety of reasons, not least because such units are necessary only intermittently, notably during systemic droughts when the country's massive hydroelectric system is unable to cover existing demand. The problem, discussed in Part IV.A.1.(d) above, is that natural gas supply contracts must be non-interruptible, in order to cover the costs of delivery. Neither IPPs nor offtakers nor Petrobras (the Brazilian oil and gas utility) was eager to accept this risk. Under pressure to avoid a crisis, the government authorized a number of special IPPs that generally passed this risk either to consumers or to Petrobras. Generally, these IPPs fell into three categories: (a) projects that operate on a "quasi-merchant" basis, selling power only through a variety of short-term contracts and in the spot market, but with revenue guarantees from Petrobras, the Brazilian natural gas company,[241] (b) projects that sold their power under long-term contract to state owned distribution companies, which received a guaranteed pass-through of their costs, and (c) so-called "self dealing" projects that sold power under long-term contract distribution utilities that were owned by the same parent as the IPP. When hydrological conditions returned to normal (actually above normal), the thermal units again looked expensive and unnecessary; the stability of original arrangements reflects the incentives of the key contract counterparty. While projects that have Petrobras or other state owned distribution companies as counterparties have almost universally run into poor outcomes,[242] the four "self-dealing" projects largely continue to operate smoothly. The only major disruption among plants in this last category has come for Iberdrola's Termopernambuco—the plant accounts for such a large proportion of generating costs for Iberdrola's distribution company that when the company passed the

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[239] Woo, *supra* note 80, at 42, 56.

[240] This point is somewhat debatable. Some critics point out that if Brazil had managed its reservoirs more effectively in the run-up to the crisis, the shortage would have been far less severe. Adilson de Oliveira, *The Political Economy of Brazilian Power Sector Reform*, *in* VICTOR & HELLER, *supra* note 12, at [page]. Nonetheless, most industry participants agree that some additional thermal capacity would have been necessary to avert the crisis altogether. Although thermal plants in Brazil have been running at very low dispatch since they actually came online, due to heavy rainfalls after the drought, this challenge looms again. By some estimates, Brazil will face a shortfall in electricity again by 2007. This time, the shortage will reflect actual generating capacity, not only poor hydrology. The country will need all of its thermal units to be ready to run—unfortunately, gas supplies appear to be far short of what will be necessary, as they were during a 2003 drought in the North East.

[241] This unusual arrangement reflects the effort of the government to encourage the construction of gas-fired power plants—a policy that involved the government instructing state-owned Petrobras to offer these revenue guarantees even though Petrobras does not actually take delivery of the electricity.

[242] Two of three "quasi-merchant" thermal projects that have a revenue guarantee from Petrobras have ended in arbitration (although the Termoceará project was since acquired by Petrobras outright). Two of four thermal IPPs that have contracts with public distribution companies have been involved in public disputes or arbitration with the offtaker (Manaus, Araucaría).

costs through to consumers retail tariffs rose steeply, prompting a barrage of public interest litigation.[243]

(c) Commercial Planning and Flexible Management

The discussion in Part IV.A.2 focused on various attributes of system planning that often affect the outcomes for IPPs; these include the supply-demand balance and the adequacy of transmission capacity. Governments are notoriously poor at making any of these estimates in a transparent or accurate manner, which suggests that IPP investors must engage more in their own rigorous assessments of power needs (and costs) rather than relying on government projections. Even if the government believes its own forecasts and makes commitments to IPPs on that basis, such commitments can unravel when the forecasts prove wrong.

In practice, a wide array of factors have allowed questionable planning decisions by governments to go untested for prolonged periods of time. In Poland, Enron's ENS operated as the country's only greenfield IPP for several years—with relatively little scrutiny and comparison to other potential projects—before the Polish government began attempting to cancel the PPA when efforts to liberalize the electricity market as part of the EU accession process invited new scrutiny for IPP arrangements. In the Philippines, all of the early fast track projects operated for about a decade until broader troubles in the power sector caused politicians to look more closely at IPPs, only to discover that continued IPP investments had been predicated on exuberant forecasts for demand. Projects that entered in these early waves often could capture high risk-adjusted returns for many years before macroeconomic shock or political pressure began to erode their position.

Nonetheless, project operators must be prepared to accommodate changing circumstances. Commercial viability is not a static concept. As a country's IPP program develops, some IPP investors have adjusted their strategies to remain competitively positioned. A striking example of this is Mirant's highly profitable[244] portfolio of IPPs in the Philippines, which the firm adjusted in fuel and technology to anticipate important shifts in the private power sector. CEPA/Mirant developed the first IPP (diesel-fired Navotas I),[245] a subsequent emergency expansion project (diesel-fired Navotas IV), the

[243] Termopernambuco now sells electricity at roughly double the prevailing market rates, and is responsible for a 17% increase in retail tariffs in Pernambuco.

[244] Overall, the portfolio is quite profitable, generating revenues of roughly $500 million annually from 2002-2004. Mirant has consistently ranked among the most profitable companies in the Philippines; in 2001 and 2002, Mirant was the top earning corporation in the country, and in 2003 Mirant subsidiaries accounted for three of the ten most profitable companies in the country. *See also*, Mirant Corp. 10-K (2005) ("Our power generation businesses and our integrated utilities in the Philippines and Caribbean continue to provide consistent, stable gross margin and operating cash flows.").

[245] The Navotas projects were intended to address the looming electricity crisis. The PPA terms were relatively short, and the fuel & technology choices reflected the need to build and operate the plants quickly; these diesel plants quickly became commercially obsolete when larger baseload coal and hydro IPPs entered the Luzon grid in the mid-1990s. As a result, the Navotas projects saw low utilization rates for the rest of the decade. Data provided by Mirant (Philippines), and corroborated in records maintained

first baseload coal IPP (Pagbilao)[246] and participated in one of the first natural gas-fired plants (Ilijan).[247] These projects included some standard risk engineering, such as front-loaded cash-flow profiles[248]; both Sual and Pagbilao were criticized in the IAC Review for rapid payback periods, reflecting for example the fact that Pagbilao paid out 59% of the initial equity investment in its first four years of operations (1996-2000).[249] Yet, Mirant has also proven very capable of navigating the turbulent and politically charged waters of the Philippine power sector gracefully; in the renegotiations following the EPIRA review, Mirant was ready to protect its profitable position, and was the first company to reach agreement with the government.[250] While the revenue implications of this agreement were not trivial,[251] the settlement had no pro forma impact on the financial terms of the contracts, notably the debt service.[252]

Finally, IPPs must be nimble when governments change their objectives for private power. Often governments espouse goals for IPPs that imply the tolerance of

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by the Department of Energy. For full utilization rates over time in Mirant's Philippine plants, *see* Woodhouse, *supra* note 75, at 34. While costly, these plants were seen by the Philippines government as essential to eliminating the power crisis and also as critical demonstration projects on the mechanisms for attracting private investment in the country.

[246] Subsequently, coal-fired Sual Pangasinan also entered service, leading the way in diversifying the Philippine fuel base from expensive oil to coal—a move that likely prevented further major disruptions in the late 1990s when oil prices began to climb after a decade of decline.

[247] Excluding fuel cost, the project was the 7th lowest cost IPP in levelized terms. INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002). Ilijan was also one of the first plants to receive only a partial performance undertaking (under a 1995 government initiative to phase out the use of full guarantees), rather than the full PU that dominated during most of the 1990s. Kepco later paid an annual fee of $800,000 to expand the coverage of this guarantee. *Id*.

[248] Frontloading cash-flow can drastically reduce the amount of time that an investor must depend on contract stability to earn the expected return. Frontloading this in way is a conspicuous component of "risk-engineering" methods of risk management.

[249] INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002).

[250] Mirant's agreement with PSALM became effective in March 2003. Mirant Corporation, 2004 10-K, at 16.

[251] Mirant's SEC filings state that revenues at the Pagbilao station decreased by $8 million in 2004 and an additional $3 million in 2003 as a result of the agreement; overall, the net present value of Mirant's contributions reached over $165 million.

[252] Mirant 10K. The principal provision of the agreement had been a commitment by Mirant not to exercise its rights under a peculiar "overnomination" clause common in Philippine PPAs—this clause allowed a generator to nominate up to 105-110% of contracted capacity for the sake of calculating availability payments. This provision was intended to encourage investment in generation capacity, with the result that actual nameplate capacity of plants built was much larger than that originally contracted by the Philippines offtakers—an arrangement that made it difficult to plan and, not surprisingly, became unsustainable when developers made extensive use of the provision. Most project stakeholders, including sponsors and lenders, appear not to have included revenue from the overnomination arrangement in the original pro forma plans for the projects. Thus, substantial profits were reaped for many years, yet the elimination of the practice did not jeopardize debt-service and did not materially change the original agreements.

IPPs that have higher costs than incumbents; yet, in reality, the host government may not weigh these benefits heavily when the differences in cost become transparent. China, in its aggressive pursuit of foreign IPP investors was interested in attracting *foreign* capital and *foreign* technology, while also protecting local markets. Thus, most foreign IPPs were not allowed access to debt from Chinese banks and were encouraged to bring in technology from abroad. In the early development of the Meizhouwan project, the developers were even told not to rely on local coal for the project, because that region of China was experiencing shortfalls in its coal supply at the time. In Brazil, the government professed the desire for thermal power plants in an effort to boost the reliability of the hydro-dominated electricity system. The new plants built have provided those additional reliability benefits, but those benefits have faded from memory in the face of the cost differential between the must-run thermal plants and surrounding hydro facilities.[253] In the Philippines, the large hydroelectric projects (CBK, Casecnan, San Roque) have faced particularly harsh popular criticism and political treatment. Among other objections, each is criticized as being inordinately expensive—a fact that may reflect the delivery of subsidized irrigation water for surrounding communities. The reasons justifying these choices faded once the immediate need was met and the cost of the arrangement became clear, to the detriment of foreign investors.

While IPPs can play a central role in introducing new fuels, in some of the most successful cases the new fuels were also competitive with incumbent power supplies. In the Philippines, the coal-fired IPPs that entered service in the late 1990s (including Pagbilao, Sual, and Quezon) came at substantial cost per megawatt of installed capacity.[254] However, these projects also filled an important need to diversity the fuel mix away from expensive oil, particularly when oil prices began rising in the latter part of the decade.[255] In Mexico, the IPPs have largely spearheaded the introduction of natural gas into electricity generation. However, the Mexican government awarded all its IPPs through effective competitive bidding and offered secure repayment terms, which helped to secure competitive prices; in addition, the regulator has actually retired old, dirty and inefficient plants—especially the costly oil-fired plants—and thus avoided overcapacity and low dispatch that often obscures the potential efficiency of private generators. To remain sustainable, IPP developers have had to focus on how their projects compare to the cost and performance of the incumbent grid-connected system.

(d) Local Partnerships

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[253] As discussed in Part IV.A.4, this problems is exacerbated by the structure of the gas markets in Brazil which require thermal plants to run at inflexible levels. In other countries, gas fired plants are more flexible and can be dispatched according to the needs of the system.

[254] Quezon was approximately $1900/MW, Pagbilao $1268/MW, and Sual $1000/MW of installed capacity. Among other things, this difference likely reflected declining risk premia and more competitive bidding in the Philippines as the 1990s progressed, the reliance of Pagbilao and Sual on sovereign undertakings by the Philippine government, and Quezon's location in a politically delicate area of the country.

[255] These three plants comprised most of the increase in coal generation in the Philippines from 6% of total generation in 1996 to 40% by 2001. *Source*, World Development Indicators, World Bank.

Among the most prominent strategies employed by investors operating in a foreign environment is reliance on partnership with local actors. This is seen as a way to facilitate communicating and operating in a foreign environment; it is also prized as a way to mitigate the political risks inherent in being a foreigner, and in some cases to recruit influential local actors to defend the project from government or other interference. The need to manage these risks is particularly acute when, as in electric power, the investment is prone to a high degree of politicization.

In the IPP study project sample, fifteen of twenty-nine projects were wholly foreign-owned and the balance had some local equity partnership. In confronting many of the most common problems that face IPPs, projects with local partners are substantially more likely to successfully mitigate that risk than those that are wholly-foreign owned. Figure 4 shows the relative ability of IPPs with local partnerships to manage four types of stresses that are often the proximate determinants of project outcomes: fuel supply, dispatch, non-payment by the offtaker, and renegotiation.[256]

FIGURE 4: RISK MITIGATION EFFECTS OF LOCAL PARTNERSHIPS

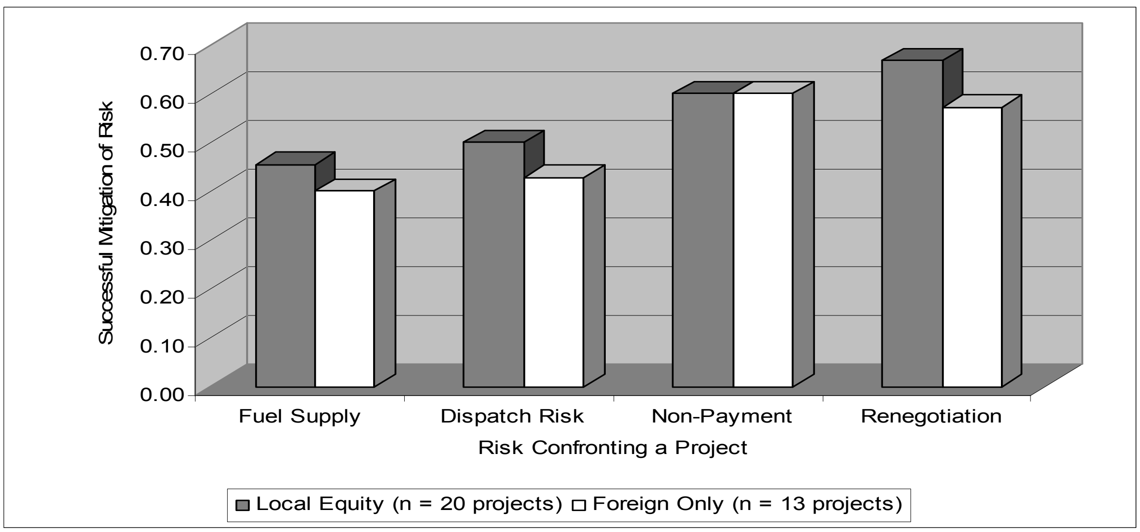

Figure 4 illustrates the basic point regarding local partners—in most circumstances, even where the partnership is fruitful and harmonious, such partners are most valuable addressing mundane challenges such as navigating fuel markets and helping understand the electricity system so as to avoid transmission constraints and other problems that limit dispatch. In the case of forced renegotiation of key contracts, the contacts and communication assistance from local partners may also be valuable. Their value is less striking in the classic political risk areas of non-payment, which more often

[256] Figure 4 presents the percentage of projects that have encountered and successfully mitigated a given risk. A project is counted as having encountered a risk if other similarly situated projects reported poor outcomes from this risk. "Similarly situated" projects refers to all projects subject to the same factors that cause the risk—this definition is used in order to control for the effect of country factors that will produce these risks. A project is counted as having successfully mitigated a given risk if that risk did not have a negative impact on outcomes.

require confrontation or pressure on local officials or a broader political strategy to alter the behavior of central government officials. In these settings, the local partner appears less able or less willing to exert leverage. These observations are bolstered by examining further the profile of local partners and the role they have played at critical moments in the project lifecycle.

The traditional "political insider" partner—a partner whose connections are so omnipotent that they can fix all problems—has been rare in the IPP experience. Perhaps the closest case is observed in Indonesia, where almost all twenty-seven IPPs had as a partner a member or associate of the Suharto family. These partners were often "allocated" by the ruling family as a kind of prerequisite to securing a project, but also offered political cover and access in a country where such assets came at a premium.[257] With the end of the Suharto regime shortly after the financial crisis had shocked the country's economy (and created stress for IPPs), the new government faced decisions about private infrastructure contracts that were becoming increasingly expensive as the local currency plummeted. In addition to addressing the cost of the projects, the new administration under President Habibie, set up a commission to investigate allegations of corruption (under its now famous Indonesian acronym, "KKN"). Popular suspicion of corruption in the IPP sector was thick, and although no allegations were ever proven (to our knowledge), the close family ties and non-transparent bidding process for the projects left the IPPs very little leverage in the public eye, while bolstering the position of politicians eager to assume a hard stance. The political insider partners acquired by IPPs were essential when Suharto ruled but quickly became liabilities when the political leadership changed.

The Malaysian IPP sector is sometimes seen as having investments that are politically allocated to influential insiders.[258] However, there are important differences contributing to the relatively positive outcomes in Malaysia. First, the domestic businesses that dominated the IPP sector in Malaysia were all independently viable businesses (although not always in the electricity sector—Genting Berhad, which has continued its IPP investments, was originally a gaming concern). Second, the Malaysian IPP sector was nearly entirely a Malaysian enterprise—with local investors, local capital, local fuel and mostly local construction. Nonetheless, when the state utility Tenaga came under pressure in the aftermath of the financial crisis, there were rumblings about the need to address the "expensive" IPP contracts.[259]

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[257] The author is indebted to Professor Louis T. Wells at the Harvard Business School for discussing early drafts of a forthcoming book on the history of foreign infrastructure investment in Indonesia that includes in-depth treatment of the IPPs in that country. *See* LOUIS T. WELLS AND RAFIQ AHMED, [MAKING FOREIGN INVESTMENT SAFE: PROPERTY RIGHTS AND THE PRIVATIZATION OF INDONESIAN INFRASTRUCTURE], ch. 16 (*forthcoming*, 2005).

[258] Henisz, Witold J. and Bennet A. Zelner, The Political Economy of Private Electricity Provision in Southeast Asia, A Working Paper of the Reginald H. Jones Center, WP 2001-02 (2001), at 32–34.

[259] Rector, *supra* note 73, at 12; S. Jayasankaran, *Lighting Tenaga's Path: Malaysia grapples with an untenable power market*, FAR E. ECON. REV., Nov. 7, 1996, at 93.

Public information regarding the resolution of the crisis in Malaysia's IPP sector is scant, reflecting the likely reliance on unofficial channels for handling the problem; the ingredients of classic insider governance in the Malaysian sector were all present. First, the government was a controlling shareholder in the publicly listed Tenaga—it appointed the Tenaga board and had final authority over any significant corporate decisions. Second, Tenaga itself held a 10-20% stake in most of the IPPs when most of the post-Asian crisis action occurred. Third, the principal lenders to the IPPs were state controlled—most of the banks lending to the projects were state banks, while the largest (and sometimes the only) bondholder providing funds to the IPPs was the state pension fund. Finally, most of the IPP deals had been led by investors with close ties to the Malaysian government—long term relationships, both within and without the IPP sector, were on the line. In short, the Malaysian "partners" were all intimately tied with government—often the government itself. Available evidence suggests that the Malaysian IPPs have fared just fine since the crisis.[260]

More common than the "political insider" are partnerships with domestic private companies. In fact, in the sample of countries and projects in this study, it is difficult to find examples of successful projects that do not have a local partner. These partnerships focus on supporting the operations of the project, such as by navigating local input markets or by managing relationships with employees and government officials. These benefits are subtle, and often difficult to evaluate without in-depth treatment on a case-by-case basis.

The Shandong Zhonghua project in China, discussed earlier, was able to access low cost local input markets, which were unavailable to wholly foreign IPPs in China, by working through their local partner. Investors in Poland have avoided some coal-fired plants in which the labor force was unionized, to avoid tangling with the powerful coal unions. The principal benefits that project managers identified when they extolled the value of local partners have been relatively unexciting but the important grist of business—arranging meetings, identifying appropriate contacts, explaining local business or government practice, managing relations with employees or state officials.

The IPP study encountered no cases where the local partner deployed political resources to resist government pressure or other classic political risk. The closest example, that of the Kondapalli project in the Indian state of Andhra Pradesh, actually turns on the benefits of local partners in navigating the local business environment—not on the partners' influence on government decisions. A set of competitively bid projects that signed PPAs with the state utility (the Andhra Pradesh State Electricity Board at the time, but known today after unbundling as "AP Transco") in 1997 were caught in the crosshairs of gas politics in India. As with many IPPs in India, these projects were designed to run on naphtha, with an anticipated shift to natural gas when new gas fields came online. The PPAs included a pass-through provision for fuel costs and an allocation of gas from GAIL, but only for projects that reached financial closure by December 1998. That same year, the Indian government deregulated naphtha prices,

[260] Rector, *supra* note 73, at 12-14.

which rose sharply and translated into a steep escalation in the cost of power from naphtha burning plants. (And as naphtha rose in price, gas allocations failed to meet targets.) Only one of the tariff-bid in the pipeline at the time, Lanco Kondapalli, met this deadline.[261] All other projects were required to lower their tariff so that it equaled the lowest fixed cost bid in the original tender.[262] Faced with new power sales arrangements and struggling to secure gas in an unreliable and evolving gas market, these new low-tariff projects have proceed slowly, and by 2005 none of these projects had reached commercial operations. Lanco Kondapalli, after lowering its tariff somewhat (although by far less than the other plants) and covering the cost of the conversion to natural gas, was commissioned in 2000 and has been performing under the PPA ever since. In an interesting twist, the Kondapalli project was also built at a cost lower than projected, which has invited a subsequent disagreement regarding whether those savings should be passed through to consumers by further lowering the tariff bid. Nonetheless, AP Transco payments reflect the full invoices submitted by Kondapalli.

What distinguished Lanco Kondapalli from the other tariff-bid projects? The AP government's reluctance to pressure Kondapalli seems to reflect both the fact that there was no clear means of handling the changing circumstances by pressuring the PPA contract, because Kondapalli had secured financing in advance of the set deadline. Kondapalli's financial close and the start of construction—all aided by local partners who had helped the project operators put "facts on the ground"—placed meaningful constraints on the government's ability to reduce the tariff. Instead, the government found leverage on the other five plants, which were in a weak position because they had failed to meet the contractual deadline and were facing an inability to get natural gas to fire their plants.[263] Finally, Kondapalli is one of the few projects in India that enjoys a fully operational escrow arrangement that deducts payments from AP Transco revenues before those revenues even reach AP Transco accounts.

The principal costs of local partner arrangements flow from the fact that such arrangements often generate new risks in project governance. The interests of the local

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[261] Notably, Kondapalli reached financial close during the heart of the Asian financial crisis, which although not substantial in India, did make large scale borrowing difficult. This was largely driven by the personal efforts and reputation of the project's domestic sponsor.

[262]This was Gautami Power's fixed cost bid of $0.06/kWh (foreign exchange component) and 0.69 rupees/kWh (local currency component). This account, repeated in several forms by industry participants in Hyderabad, is recounted on the website of the Andhra Pradesh government, at http://www.aponline.gov.in.

[263] In extreme cases, disputes over performance and costs can appear somewhat pretextual. In the Miezhouwan case discussed earlier, project sponsors maintain that local government officials had no basis for raising technical objections, other than to delay commercial operations (and full tariff payment). A common (though unverified) account of one episode in the Dabhol controversy has Maharashtra officials reducing dispatch gradually until the plant shut down, then requesting full dispatch in three hours from a cold start. The PPA required a three hour horizon for full availability; project management protested that this provision did not contemplate ramping up from a cold start (a requirement almost any power plant would have trouble with). Despite protests to the contrary (and the fact that a court would likely find such a failure immaterial), the inability to comply with the requirement eroded the leverage of the Dabhol sponsors in the dispute.

partner may diverge from those of the foreign investor, and it can be difficult for the outside investor to police the behavior of its partner. With the exception of China, most of the poor experiences in local partnering have come in projects in which the local partner was the controlling stakeholder in the project company—a setting most likely to yield diverging interests and weak oversight.

Diverging interests can lead, in extreme examples, to local partners blocking enforcement actions, as in the case of the Pillai Perumal Nallur ("PPN Power") project in Tamil Nadu—a 330 megawatt baseload plant firing on naphtha (with a planned transition to natural gas) that sells electricity to the Tamil Nadu Electricity Board (TNEB) under a 20-year PPA. Local partner Apollo Infrastructure Projects Finance promoted the project with the largest equity stake (28%); the project's other equity partners are Marubeni, the equipment supplier (26%), El Paso Energy (26%) and PSEG (20%). In 2001 TNEB announced the decision to pay its five IPPs only 2.25 Rs./kWh, and it failed to pay even this amount to PPN Power.[264] When the plant missed its first quarter 2003 debt payment obligation of Rs. 5 billion (approximately US$107 million) the plant lacked money to buy fuel and shut down.[265] In response, PSEG and El Paso sought to have the project company file an arbitration claim against the state government of Tamil Nadu, but this effort was blocked by the local partner who worked with one of the foreign investors (Marubeni) in defeating the proposed board resolution for arbitration by a vote of 8 to 5.[266] Instead, PSEG Global and El Paso initiated arbitration proceedings on their own behalf before the International Court of Arbitral Tribunal seeking to recover Rs. 4.69 billion (approximately US$100 million) owed to the project by the TNEB. The project is now embroiled in controversy as the project company filed anti-arbitration suits against El Paso and PSEG in Indian court. Overdue receivables from TNEB to the project as of December 21, 2002 were $36 million[267] and by 2004 had reached $110 million. In 2005, El Paso sold its stake in PPN for $20 million—a poor return on an original investment of $41 million.[268]

However, many IPPs in India (e.g., GVK, Lanco Kondapalli), China (e.g., Shajiao C, Shandong Zhonghua), Thailand (e.g., Independent Power, Bo Nok, Union Power),[269]

[264] *TN Decision on PPN Power Arrears Stuns Industry*, Financial Express, Apr. 20, 2003 (recounting the TNEBs decision to temporarily withhold payments from PPN, unlike the other IPPs in the state).

[265] PPN originally fired on naphtha, provided under a long-term fuel supply agreement with the state-owned Indian Oil Corporation. When naphtha prices spiked, causing the price of PPN's electricity to also rise steeply, the project switched to a combination of naphtha and natural gas based on a gas allocation for 60 percent of its capacity. The project expected to obtain a full gas allocation from GAIL before the end of 2003, but is now seeking to close a deal with the private Hindustan Oil Exploration Company, Ltd., for gas from the offshore PY-1 field, in the hopes of bringing its electricity prices down and improving its attractiveness to TNEB.

[266] N. Ramakrishnan, *TNEB dues: PPN's Two US partners go for arbitration, Majority shareholders vote against the decision*, Business Line (The Hindu), Nov. 16, 2004.

[267] El Paso Corporation, Form 10-K, at 150 (2003).

[268] El Paso Corporation, Form 10-K, at 63 (2005).

[269] The last two projects in Thailand—Bo Nok and Union Power—are the two coal fired projects that failed in the face of public resistance to the environmental impact of coal-burning power plants (likely in

and Brazil (Termoceará) have a similar equity division between foreign and local partners (in which the local partner holds a high or controlling share in the project). Each of these projects has faced disputes of varying severity, and in five of seven cases in which a foreign investor was involved, that foreign investor has since exited the project. While the terms on which the foreign investor has sold out of each project are not known with specificity, no major shareholder disputes have emerged in any of these cases. In some cases a known mechanism protected this result (e.g., an indemnification clause in the local-foreign joint venture agreements in the Shajiao C project), but in most cases there is no factor that systematically explains the outcomes of local-foreign joint venture arrangements. While local partners can be crucial to effective operations in a new business environment, careful selection and structuring of each relationship on a case-by-case basis appear to be an undeniable fact of life for projects such as IPPs.

(e) Managing Rights, Responsibilities, and Incentives

IPPs, and any large infrastructure project, depend upon a complex network of stakeholders to operate successfully. The relations between these stakeholders are defined in a laundry list of contracts that do not only allocate risks and rewards, but also rights and responsibilities, in a way that keeps incentives aligned between the disparate parties. Aligning rights and interests to prevent and endure stress is crucial. The traditional project-financed project company has proven resilient and able to operate through substantial uncertainty and revenue instability, but doing so requires committed stakeholders who are willing and able to coordinate collective action efficiently.

Indeed, one of the reasons that the project financing structure has been robust in so many different contexts is that it is highly attuned to any changes in circumstance. This sensitivity plays a key role in keeping stakeholders' attention focused on the project; where it is abandoned, poor outcomes often result, such as in the case of Spectrum Power in Andhra Pradesh.[270] This 200 megawatt project has been a poor experience for most key stakeholders, with severe project cost overruns, time-consuming litigation, and criminal fraud all playing a part. On the surface, these outcomes largely reflect poor choice of local partner, who has been indicted for fraud in connection with his management of the plant. However, the project was also structured in a way that allowed problems to escape detection. The loan documentation had no trust and retention agreement to govern the handling of project revenues—the foreign partner and even the local banks were required to physically investigate irregularities that would have

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combination with the reduced demand for power after the Asian financial crisis). The projects, now known as Khaeng Koi II and Ratchaburi Power (respectively) have since been converted to gas and have changed sites—neither of which an easy task. The shareholding in these projects has since seen the entrance of substantial "state champion" firms (EGCO in Bo Nok and Ratchaburi in Union Power), while private Thai holdings have been diluted, and the lone western firm (Edison Mission Energy in Bo Nok) has exited. The controlling interest of local shareholders may have facilitated a smooth management of the problems in these projects.

[270] This details of the Spectrum case are related in Lamb, *supra* note 81, at 44, and is based on local Indian media reporting of the ongoing dispute, as well as discussions with project sponsors and lenders, conducted in Hyderabad, India, March 2005.

otherwise been more readily apparent. Unlike other fast-track projects in India, Spectrum did not apply for a counter-guarantee from the government of India. After the GOI's first counterguarantee—for Enron's Dabhol project—generated such controversy, the process of obtaining such guarantees became extremely arduous. Spectrum's primary lenders, the State Bank of India, did not require the counter-guarantee, and Rolls-Royce (the EPC contractor for the project) had coverage from the British export-credit agency. Without additional scrutiny, the project rolled forward with little check from authorities that otherwise would have had a strong incentive to help police the partner's behavior. Alarmed by allegations of fraud against the local partner, and the delicate financial health of the plant due to mismanagement, the lenders eventually declared an event of default and assumed control of the project in 2001.[271]

Nonetheless, such sensitivity comes with a price—with rights and obligations spelled out with such specificity, it is deceptively easy to end up with a contractual web that locks up under stress or that creates problems of its own. Notably, these include creating a project structure that is too ponderous to organize collective action,[272] providing *too much* insulation from uncertainty (as in the case of the Quezon project detailed below), or providing incentives that work under normal conditions, but collapse quickly in the face of stress (as in the case of Marubeni's operations in the Philippines, detailed below).

The Quezon project in the Philippines weathered substantial stress when the plant was unable to meet availability targets during the initial years of operations. In this case, the original agreement called for Meralco (the private utility that was Quezon's counterparty) to purchase all of Quezon's contracted output on a take-or-pay basis, whether or not that output was actually available. Resolution of a growing dispute surrounding this situation was hindered in part because the plant was paid its full operating fees regardless of plant availability. Additionally, the board of the project company was having trouble taking decisive action to resolve the operator performance issues because the board seats were evenly divided between key shareholders. With no incentive to take action to address operating problems, low availability continued and Meralco grew increasingly frustrated, eventually precipitating a renegotiation by withholding payment. In the outcome, the parties agreed to limit capacity payments to the actual rated capacity, stiffen the penalty for not meeting contracted availability (both of which were important to Meralco), and to clarify the application of the take-or-pay

[271] The government of Andhra Pradesh has since moved to file criminal charges against the local promoter, alleging fraud in the management of the contract.

[272] Evidence of the cost that such gridlock imposes on projects has been difficult to obtain because it resides in the most sensitive moments of already sensitive projects. This phenomenon has been noted in some well-documented cases. In Enron's Dabhol plant in India, for example, the project entered technical and real default under various agreements almost immediately upon the MSEB's failure to make payments under the PPA, and lenders resultant suspension of disbursements related to Phase II of the project, which induced an additional default, this time to the project's EPC contractor. From this dismal beginning, in addition to intransigence by Indian government officials, the project company reportedly was also unable to coordinate action among project stakeholders to develop a renegotiation strategy and the project slipped into deeper distress. Piyush Joshi, *Dabhol: A Case Study of Restructuring Infrastructure Projects*, 8 J. OF STRUCT. & PROJ. FIN. 27 (2002).

terms to specify that Meralco must take all contracted energy that is available from Quezon (which was important to project sponsors).

The importance of keeping incentives aligned between investors and key government counterparties is also striking. When the central government role is purchasing the IPPs electricity, this can be difficult. Some projects have come close to crisis primarily because the incentives of the government party had not been planned adequately. Two geothermal BOT projects located on Mindanao in the Philippines developed by Japanese firm Marubeni in the late 1990s have weathered disputes that similarly reflect the difficulties that follow when interests diverge. Geothermal development in the Philippines run through the Philippine National Oil Company-Energy Development Company ("PNOC-EDC") a state-owned firm that holds a monopoly over geothermal reserves in the country. In this case, the Marubeni projects were to receive steam from PNOC-EDC, convert it to electricity, and deliver the electricity to NAPOCOR on behalf of PNOC-EDC.

However, it was formally PNOC-EDC that held a power sales agreement with NAPOCOR to feed electricity into the Mindanao grid. The overlapping power sales agreements were structured such that PNOC-EDC was caught between two obligations that could, and did, diverge. PNOC-EDC's payments to Marubeni for converting steam to electricity were primarily dollar-denominated and tied to capacity levels based on an annual "nominated" capacity demonstration that could range as high as 104% of the original plant design. This capacity payment was on a "take or pay" basis—as long as the projects were capable of delivering power at nominated capacity levels demonstrated on an annual test basis, PNOC-EDC had to pay—regardless if Napocor accepted delivery of that much power or not.

At the same time, PNOC-EDC's power sales contracts with Napocor were peso-denominated, and these contracts also allowed the utility to limit its annual consumption of electricity to a level in the range of 93% of the plants' design. In the end, Marubeni's projects were efficient, the peso devalued, electricity demand fell, and Napocor limited its purchases of power from PNOC-EDC to the minimum levels. PNOC-EDC was stuck paying in US dollars for higher levels of capacity than it was able to sell to Napocor. Additionally, Napocor's payments to PNOC-EDC for electricity were still in pesos, which continued losing value against the dollar until 2002. The parties' solution to this dilemma was to limit the projects' annually nominated capacity to the 100% design level despite the fact the projects were capable of demonstrating a much higher capacity—this solution was supported as demand in the Mindanao grid in the Philippines began outpacing supply and Napocor started taking all the electricity it could.

These accounts are vivid, but hardly unique in the IPP experience. Success often demands flexible responses to changing circumstances; projects that have successfully resolved disputes[273] in the sample of countries examined here have generally relied on

[273] For purposes of this discussion, the successful resolution of a dispute means reaching agreement with relevant counterparties that addresses the main issues of contention. This is not an unproblematic definition, as the experience may still be a negative one for investors and government alike, sufficient to

one or more of the following actions: refinancing project loans, restructuring or changing fuel supply, identifying elements of existing contracts that they would like changed (creating the possibility for a mutually beneficial negotiation), and maintaining open communication with relevant government counterparties. These steps place a premium on the capacity for organizing cooperation and decision-making, establishing critical financial or operational flexibility, and managing relationships with key government and other counterparties.[274] Often, the nexus between contract and reality is blurry—for example, while many projects spend some time in a period of technical default under the loan documentation, lenders have rarely exercised their full rights under the loan documentation, rather allowing time and negotiation to resolve issues. The point is not that contracts should be flexible or more permissive, but rather that they must be arranged in a way that anticipates stress and that success may demand moving past their strict terms.

V. THE FUTURE OF THE INDEPENDENT POWER PROJECT.

Although stagnant since the late 1990s, a new round of investment in the power sectors of emerging markets is taking shape. Despite the difficulties with the first round of IPPs, many investors and hosts alike expect that IPPs will continue to be an important aspect of overseas and infrastructure investment. Indeed, eleven of the twelve sample countries rely explicitly on private investment to play a part in meeting generation needs in the near term.[275] This section examines the prospects for this market and makes two main points.

First, the size of the future IPP market is likely to be smaller than the market of the 1990s, reflecting both reduced tolerance of foreign investors for such projects and reduced demand in many countries. In many Asian countries, where IPP investment has been particularly heavy in the past, general economic reforms have created emerging markets that can mobilize capital on their own. Where those conditions exist there is a lesser need for "classic IPPs"—truly independent, private investments in standalone generators that were able to offset their higher costs by their ability to raise capital efficiently in international markets.

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deter further experiments with such private investment. However, understanding the process may help plan more effectively to manage stress in future projects. Further, emphasizing the value of cooperative renegotiation is not without basis; at least one study of large engineering projects has found a positive correlation between the capacity to adjust to unexpected problems and changes in circumstance and project performance. *See* Miller & Floricel, *supra* note 274, at 149.

[274] Roger Miller and Serghei Floricel, *Building Governability into Project Structures*, *in* MILLER & LESSARD, *supra* at 130-150, 137. This is particularly true in the case of project financed IPPs, in which project lenders hold a veto of any substantial decisions taken by the project company. The restructuring of such projects is a very delicate process that demands an investment of time and attention from sponsors, lenders or a lending syndicate, contractors, a variety of government officials (often from different ministries that may have conflicting agendas), and other stakeholders such as NGOs and local communities. For a review of the considerations at stake in these restructurings, see Steven T. Kargman, *Restructuring Troubled Power Projects in the Emerging Markets*, 8 J. OF STRUCT. & PROJ. FIN. 19 (2002).

[275] The exception here, Egypt, reacting in part to the steep escalation of IPP prices in local currency terms following the devaluation of the pound, has returned to state finance for its next round of investment.

Second, the enterprises that build IPPs will be (and in many cases already are) markedly different. In recent years, many of the European and US firms that dominated the first round have exited (often following considerable losses), and a new set of regional firms that straddle the public/private divide has assumed center stage. Power sector reforms, while often partial, have fostered a class of enterprises that are comfortable operating in markets that are in flux. While the rise of regional investors has been widely noted in recent literature, the differences that set these new power companies apart from their predecessors are more substantial than their country of origin.

Finally, while the overall argument is that the market for classic private power producers will be smaller, investors are likely to face challenges flowing from the host country context that are quite similar to the first round. Unstable macroeconomic conditions, opaque and politicized institutions of governance, and ambiguous power sector reforms will all be persistent challenges. IPP investment must be designed for that imperfect context. With this in mind, the final two sub-parts discuss some implications for governments (Part V.C) and for investors (Part V.D).

A. <u>The Size of the Market for IPPs</u>.

In each of the twelve countries examined in this study, reforms of the electricity sector remain in flux. The most common environment for a private power producer is one of partial reform—a hybrid market that combines elements of market activity with large state dominated sections.[276] Analysts often assumed, and continue to assume, that partial reform was just a brief stopping point *en route* to a more fully restructured power sector—with independent and competitive generation companies and privately owned distributors.[277] Instead, partial reform has become a stable endpoint. Analysts are increasingly aware that the pace and direction of reform is driven fundamentally by the political economy of the domestic electricity market.

The stasis of reform efforts has large implications for the IPP market. A new class of power investors has emerged that are adept at operating in uncertain environments. Discussed in more detail in the next section, these “dual firms” have raised the risks for private investors in classic IPPs because they must compete on a playing field that appears to be tilted against them. Classic IPPs believe (probably correctly) that they can’t compete with these dual firms that dominate in partially reformed power markets and enjoy an advantage due to their combination of political and market strength.

At the same time that the competitive setting for IPPs has narrowed, so too has the need for private capital. Capital market reforms along with direct state subsidies have made it possible for dual firms to obtain the capital needed for investments, thus

[276] VICTOR & HELLER, POLITICAL ECONOMY OF REFORM, *supra* note 12, at [page].

[277] The fully restructured power sector was the vision of “textbook” power sector reform; for a summary see *id*. at [page].

eliminating one of the original rationales for classic IPPs. In China, for example, essentially all the capital for new power sector investments now comes from domestic sources channeled through state-dominated generation companies such as Huaneng, Datang or China Power International.

In addition to this structural disadvantage for classic IPPs, the continued churning and uncertainties in power sector reform create political risks that the original IPP firms—namely, wholly private and usually foreign investors—have been unable to manage.[278] Such commercial difficulties that arise from market power along with uncertain and variable electricity reforms are evident in the Philippines. A planned bilateral contract market has been gridlocked as it depends on the participation of hundreds of small, private distribution cooperatives that have never operated in such an environment; in additional to adjusting to a radically different operating environment, they worry, with reason, that they will be stuck with expensive contracts while generators poach large consumers with attractive direct contracts. At the same time, state utility Napocor is barred from signing new power purchase agreements with IPPs.[279] Thus, securing sales contracts sufficient to get a new power plant financed requires navigating the dense local commercial environment of the Philippines[280]—an almost door-to-door sales campaign that new foreign entrants would likely find impossible.

All three of these factors—the rise of dual firms, new sources of domestic capital, and the difficulty of competition where market rules are in flux—explain why the market for classic IPPs is likely to be smaller in the future. It is not clear whether this leads to domestic power sectors that are less competitive. On the one hand, the sharply smaller IPP sector will reduce competition worldwide. On the other hand, the new marketplace where there is greater reliance on domestic investment in the power sector will ease some of the risk management problems that the original classic IPPs often were not able to tame despite their prodigious efforts at risk engineering. Increased reliance on local capital has cut exposure to foreign exchange liability; it has also allowed for greater emphasis on local familiarity and expertise. The result, it appears, is a more stable long term commitment to the domestic power market as well as lower prices that reflect lower risk premia.

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[278] Even countries continuing to rely on state dominated single buyer systems for purchasing private power will likely face increasing instability in the near term. This is the case in Mexico, Kenya, Egypt, and Turkey. These countries, however, are increasingly confronting the systematic limitations of the model IPP framework that depends on foreign investment, and uncertainty looms over continued investment as government and investors grapple with risks no one wants to bear.

[279] Republic Act No. 9136, § 47(j) (Phil.)(2001) ("Napocor may generate and sell electricity only from the undisposed generating assets and IPP contracts of PSALM Corp. and shall not incur any new obligations to purchase power through bilateral contracts with generation companies or other suppliers.").

[280] This portrayal of the business environment for new private power plants in the Philippines in 2005 is based primarily on conversations with investors and regulators in Manila, The Philippines, Feb. 20–Mar. 5, 2005. The author is indebted to Anthony Becker at GN Power for extensive discussions regarding the process of marketing a potential new power plant in the new market in the Philippines. For more on this, *see* Myrna M. Velasco, *Proposed LNG power plant offers cheaper electricity rate*, Manila Bulletin Online Edition, *available at* http://www.mb.com.ph/issues/2005/08/30/BSNS2005083043156.html.

Classic IPPs will still play a role in the limited niches defined by the marginal investment needs of a given country. Even high performing developing countries will require investment beyond the capacity of their domestic firms and capital markets to meet. In some cases this threshold is imminent (as in the Philippines), while in others it is distant (as in India and China). In some countries, the domestic sources of finance are in such bad shape that a host country may have no option other than classic IPPs. Such a market was evident in India in the early 1990s and Kenya in the late 1990s; in the future such a niche may exist in the world's poorest and least well governed countries. And in some countries foreign participation will be welcome as an antidote to less competitive local markets and to set benchmarks for performance. (An additional niche for private investors includes private power supplies, such as on-site generators and private networks. Such investments will face a set of risks that are distinct from grid-connected generators, and thus are beyond the scope of this paper).

The size of the market will depend not only on the conditions in the host countries, which frame a much smaller niche in the future, but also the perceptions of investors. The large size of the IPP market in the 1990s was based, in part, on the exuberant view of investors that the many risks surrounding private power could be engineered. It is possible that the painful lessons of that investment wave will be forgotten as new managers and firms look at the market with fresh eyes and short memories—imagining that they have new solutions to long-standing problems of risk management.

B. The New Players.

The 1990s IPP market was built, in part, on the logic that private investors—notably foreign investors—were essential to financing, building and operating new generating capacity. Indeed, that market was dominated by foreign investors—notably western companies with operations scattered worldwide. Today, many of the original foreign investors have exited. This reflects, in part, that these firms have been unable to manage risks in the ways that they had anticipated. It also reflects exogenous troubles in their home markets that have forced the sale of overseas assets to cover holes in their balance sheets. In part, it also reflects efforts of parent companies to refocus on core areas of expertise—their home market. The key players in the market have since changed in two respects.

First, in the place of the western power firms that pioneered the IPP market, a new class of specialist IPP firms has come to dominate the marketplace. These specialist firms often in countries related by history or colonial ties, such as CLP in China or EDF in Francophone West Africa. The firms have survived—perhaps even thrived—in part because these "foreign" firms have become "local" in many ways, including Mirant or GN Power (a new venture by the original sponsors of the Quezon project) in the Philippines, or possibly Iberdrola in Mexico. They have also survived due to special circumstances that give these firms a longer time horizon than other western investors. EDF has been able to keep non-performing assets (e.g., its Light subsidiary in Brazil) in

part because it has excess capital from its monopoly home market. CLP has invested in China, partly, because credibility in its home market of Hong Kong requires a presence on mainland China. Globeleq has bought distressed power plants in Africa and is managing them for the long-term in part because their risk profile is distinct from a typical private firm—the UK government-owned firm has a charter to promote development through power infrastructure investment. For similar reasons, IPS has signed on to restart the Bujagali hydro project in Uganda.

The second change in identity concerns the rise of "dual firms" that are expanding into the niche originally intended for classic IPPs. Reform efforts in many countries have neither fully dismantled the old state-owned enterprises (SOEs) nor spawned the emergence of truly independent competitive companies. Rather, most reform efforts have yielded a hybrid: firms that are laden with the political assets typical of SOEs and necessary to operate in a politicized power market and yet also exposed to market forces that put a premium on good management that is more typical of private ownership and competition. These dual firms resist a return to the old integrated state system, but they also resist further imposition of reforms that could erode their privileged position.[281] One category of dual firms are the state companies that have adopted increasingly sophisticated aspects of private operation, such as NTPC in India, Huaneng in China, or EGCO in Thailand.[282] A second category includes domestic firms that have grown skilled at managing the political and social expectations of infrastructure investment—Reliance and Tata in India being prime examples.

All of these new actors—the new foreign investors and the domestic dual firms—are characterized by the ability to deploy assets unavailable to classic foreign IPP sponsors from industrialized countries. In some cases, these new actors tolerate demand for lower returns and are more permissive in how they price and account for risk. In all

[281] This is true not only of IPPs, but of reforms generally. *See, e.g.*, Victor & Heller, at [page] (finding that the process of electricity sector reform often caters to firms that exhibit characteristics of both private business acumen and public ownership); Joel S. Hellman, *Winners Take All: The Politics of Partial Reform in Postcommunist Transitions*, 50 WORLD POLITICS 203 (1998) (finding that the most likely winners from economic reform are similar "dual" entities that are able to position themselves across the public-private divide, and which often impede further reforms in order to protect their special status); Amanda Perry, *supra* note 109, at 1653 ("When differences between foreign investors are noted, it seems that those who are not deterred by a legal system that deviates from the Ideal Paradigm are considered to be of less value to the host country. For example, the FIAS program recognizes that the discretionary behavior of bureaucrats 'can be a particularly strong deterrent for foreign investors who may not be politically connected, operate under strict internal corporate guidelines, or who do not have local partners to take care of a multitude of procedural obstacles and associated payments.' It concludes that countries with such legal systems 'may lose the 'good' foreign investors they all attempt to attract.' The implication is that those investors who are not dissuaded by such legal systems are not 'good.'").

[282] Central received wisdom from the first round of investment is that improving the commercial orientation and efficiency of the host utilities must be integral part of reform. This is true, but makes these firms more likely to compete against private counterparts, which is a pattern observed in these countries. *See* Frank Sader, Attracting Foreign Direct Investment Into Infrastructure: Why is it so Difficult?, Foreign Investment Advisory Service Occasional Paper No. 12 The World Bank & International Finance Corporation, 1999) at 29 (identifying competition from newly independent and commercially oriented state firms as a key challenge for line ministries seeking to expand private sector involvement in infrastructure services).

cases, these firms rely on extensive networks of relationships with domestic power purchasers and public sector officials. They have become adept at operating where newcomers would be at a great disadvantage. In the Philippines, for example, these firms are selling contracts to electricity cooperatives in the gridlocked bilateral contract market; these firms have also proved adept at protecting profits while engaging in social and political give-and-take, such as Mirant's role in leading the PPA renegotiations in the Philippines. New entrants in China's notoriously difficult power market are operating on the assumption that they must operate as local firms do in all respects, including cost of capital and equipment; these firms pursue traditional contracts only after making an investment decision on the basis of independent commercial analysis of the market for a potential project.

It appears that these new actors do not suffer the extreme problems of economic inefficiency that plagued the SOEs before them. Indeed, their cost of capital, long time horizons, and good management allow them to build and operate projects at lower cost, and comparable efficiency, often at the world standard set by classic IPPs. Often, the entrance of IPPs have coincided with other reforms to liberalize the economy, which have opened new opportunities for state power firms. In India, changes in trade policy allowed state firms to access new technology at the same time that IPPs were entering the country with similar technological and financial innovations. Today, in Andhra Pradesh and Gujarat projects developed by new entities—including dual firms and some government-owned enterprises—are among the most efficient and environmentally friendly in each state.[283] The question of whether these projects include hidden subsidy is not uncontroversial; nor is there much agreement on how much of the high cost of classic IPPs was due to decisions by government officials that amplified risk premia. Nonetheless, the fact remains that increasingly efficient state-developed projects provide a critical (and unflattering) benchmark for private projects. This disparity has been a key factor in government official's disappointment with the IPP experience in several countries.

C. Elements of a New Model: Implications for Host Governments.

While the market for classic IPPs is likely to be smaller than during the boom of the 1990s, IPPs can still play an important role. The enormous investment needs for electricity in developing countries, highlighted to begin this paper, outstrip any known single source of capital. The International Energy Agency estimate of \$2 trillion of investment in generation by 2030 implies annual outlays of roughly \$80 billion—almost twice the level of private investment at its peak of \$46 billion in 1996. Thus, private investment can help to set a benchmark for performance and promote competition; to ease the introduction of new fuels and technologies; to provide power when local utilities, for whatever reason, are unable to invest. This study suggests a handful of lessons for countries that are creating and managing an IPP program.

[283] P.R. SHUKLA, THOMAS HELLER, DAVID VICTOR, DEBASHISH BISWAS, TIRTHANKAR NAG, AMEE YAJNIK, ELECTRICITY REFORMS IN INDIA: FIRM CHOICES AND EMERGING GENERATION MARKETS 84 (2004) (reporting the results of a door-to-door survey of all operating power plants in each state for fuel efficiency and carbon intensity).

Insist on competitive and transparent bidding in allocating projects. Projects whose costs are out of line with other new power sources are particularly vulnerable to claims of corruption and improper awards. A well-designed, transparent bidding process helps to allay those concerns and also yields projects that are indeed highly competitive. In some settings there may be constraints on the competitiveness of a bidding process—for example, for first-of-a-kind projects or unusually extreme risks that many firms may shun—but there are no circumstances that would appear to justify auction and licensing rules that are not clear and transparent. Few countries will be as attractive to investors as Thailand in 1994 or perhaps even Mexico in 1998, yet successful attraction of private investment in competitive auctions for the power sector in Argentina in 1992 or Egypt in 1998 (countries whose general investment profile was not particularly strong at the time) suggests that transparency and competitiveness are not constrained by broad country level factors, but by particular decisions in the selection and award of projects. Investors will build power plants at extremely low prices if host governments provide clear and transparent bidding and demand low prices.

Anticipate the need to manage stress in the private power sector. This comprises both financial stress, such as that resulting from macroeconomic shock or sudden demand fluctuations, and political stress, such as opposition from civil society or entrenched interests. The introduction of private power generation into a system accustomed to operating on soft budgets and subordinated to political goals is a jarring experience. It is extremely difficult to sustain merit-order dispatch and PPA obligations when some projects operate with full cost (risk adjusted) accounting and others have loose accounts and subsidized tariffs.

All of these problems amplify when the power sector finds itself in financial trouble. A primal cause of this trouble is the insolvency of the offtaker, and where possible governments must work harder to align retail tariffs with the real cost of power and to prepare the public for the main reasons why new power tends to be more costly than old. In all, the vulnerability of IPPs to financial trouble in the power sector suggests that except in countries that have created a robust context for IPPs, such projects are likely to be more sustainable when they account for only a small fraction of the country's power. As the fraction of power supplied by IPPs rises so does the exposure to macroeconomic shock; as that fraction rises the country is less able to manage changes in circumstances because the entire IPP sector can be affected by the same shocks—evident, notably, in the Philippines. Countries that have kept IPPs to a smaller share have found it easier to weather macroeconomic shock, and now have greater freedom in deciding where to source financing for power investment in the future. Egypt is the best example, and the Philippines is an outlier for its ability to manage IPPs shocks despite a large fraction of the sector in IPPs.[284]

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[284] The Philippines, however, has been unable to reap this benefit immediately because is in the midst of a difficult transition to a private electricity market, while Napocor has been sidelined in procuring new capacity.

Many troubles with classic IPPs arise because the offtaker is caught between hard (and often rising) costs for IPP power and difficulties recovering those costs in retail or wholesale tariffs. In such settings, the offtaker will find ways to shun the power, putting pressure on contracts that can manifest in myriad ways. A committed offtaker is, ideally, financially solvent or has access to a reliable stream of subsidies to cover the gap between its revenues and IPP obligations. In addition, the best offtakers are those affiliated with reformers in the central government because such reformers, usually, are able to ensure the implementation of policies that allow the offtaker to manage its IPP obligations.

Be careful of tension between short- and long-term goals. In nearly all the IPP programs the logic for private participation included, in part, the need for long-term investment. This was reflected in long duration PPAs and the choice of plants (mainly baseload). In many cases, IPPs were viewed as a bulwark for broader competition. These visions helped to attract investors, but even where projects were highly competitive, this vision also masked a deep tension. The goals of limiting risk assumption by government in the long term and of securing high-quality investment in the near term often cut in different directions. Attracting competitive IPPs often demands compromises that would be unsustainable if replicated in the generation sector as a whole—as in the case of Argentina, in which the massive liability flowing from the delinking of the peso/dollar peg proved both financially and politically unmanageable. While offering such attractive terms to investors may be necessary in order to attract low price bids and other benefits from investors, this model is not sustainable in the long term unless the electricity sector has a history of covering costs through retail sales, and exposure to foreign exchange liability is somehow mitigated.

Be careful of the tension between power sector reform and attracting IPPs. In the 1990s, textbook reform aimed unambiguously at fully private, competitive electricity markets governed by an independent regulatory authority. Analysts imagined that these reforms would occur at the same time that private investors flooded in. Instead, reforms have yielded only a hybrid market rather than the textbook, and in some countries (e.g., Argentina and Brazil) there is movement back to a greater role for state control. Today, the pace and direction of reforms have scattered according to the unique circumstances and politics in each country. In this environment, reformers must be realistic about the likely outcomes of reform, and craft private investment in a way that does not depend on ultimate success. In the first wave of investment, IPPs developed with the expectation of further investment (e.g. Egypt's IPPs), trading opportunities (e.g. merchant plants in Brazil), or other development (e.g. natural gas projects in India and Brazil) often left investors disappointed and governments with burdensome liabilities when reforms dissolved. In contrast, projects situated to avoid the falling debris from failed reforms (e.g. hydro projects in Brazil, competitive baseload generators anywhere) have often performed well.

Thus countries face strategic choices today that are much more nuanced than they did in the 1990s. Power sector reform, in most cases, involves tinkering with rules and warring with entrenched interests. And creating the environment for private investors

involves attempts to make credible promises that rules will not change in unfavorable ways. This tension is particularly evident in single-buyer systems that dominate in most countries. Some analysts have criticized such a system for politicizing the allocation of rents and postponing serious reforms.[285] In practice, the single-buyer system has allowed countries to maximize returns from IPPs, but only with extensive risk assumption by the host government or consumers that would not be sustainable if replicated on a large scale. Thus, despite appropriate caution in embracing such a model, countries can structure IPP contracts in a way that does not unduly prejudice further reforms in the distribution sector,[286] while reaping the coordination advantages that accrue to a single buyer system.

This observation suggests caution when approaching multi-buyer electricity markets. In Brazil's multi-buyer system only the parties with special attributes—such as the capacity for self-dealing, which the government has since outlawed—have led to success for thermal IPPs. The theoretical benefits of multiple buyers—through diversity and the potential for competition—generally have been offset by the coordination costs of dispersed authority and the more complex transactions that arise when many parties are involved. Successful multi-buyer reforms in other Latin American countries, such as Bolivia and Chile, may yield further lessons for building governability into delicate investment projects such as IPPs early in a difficult reform process.

D. Elements of a New Model: Implications for Investors.

The study also offers insight for private investors in this new, albeit smaller, market.

Look beyond contracts and prices for risk management. For large scale infrastructure projects in uncertain markets, contracts and the other elements of "risk engineering" are necessary but not sufficient instruments for managing risk. However, many of the factors that lead to poor outcomes are not easy to solve with contracts; moreover, most of the contracts do not hold strictly to their original terms when circumstances change and the projects face stress. One failing of the classic IPP model of the 1990s was that in most cases investors sought to allocate risks carefully, but often they did not give sufficient attention to managing risks. Conspicuously, for example, the allocation of currency risk to government counterparties on the theory that governments had better control over that risk did not mean, in practice, that governments were more likely to avoid a currency crisis because of obligations in IPP contracts.

As a complement to risk engineering, successful IPPs have employed an arsenal of "strategic management" tools. These include, first and foremost, attention to costs so that the project does not "stick out" when circumstances change and there is closer

[285] Laszlo Lovei, *The Single-Buyer Model: A Dangerous Path toward Competitive Electricity Markets*, Public Policy for the Private Sector, Note No. 225 (The World Bank, 2000).

[286] Fiona Woolf and Jonathan Halpern, *Integrating Independent Power Producers into Emerging Wholesale Power Markets*, Mimeo (2001).

scrutiny (albeit usually unfair) that compares private IPPs with incumbent public plants. Other elements of strategic risk management include the need to conduct one's own system planning forecasts since so many projects find themselves under pressure when government forecasts and transmission planning are misguided. In addition, IPPs generally have had success in engaging local partners, but they must be realistic about the advantages and liabilities of such arrangements. Local partners generally are helpful with near-term and tactical business management; our study suggests that they play little role in grander tasks such as enforcing contracts. These tools overlap in different ways depending on the unique contours of each investment. Where some important elements are missing, careful structuring can often make up the difference. Thus, thermal projects in Brazil are unavoidable more expensive than the dominant hydroelectric sector, yet careful selection of offtaker has ameliorated pressure on payment security for the self-dealing projects.

Notably, the importance of risk management applies not only to financial terms but also the relations with local communities. As host countries are increasingly democratized and a political power is dispersed, the number of relevant groups has risen. The assumption that governments would manage political relations with the broad group of stakeholders has proven mistaken. Indeed, success stories more often reflect practices by investors rather than by government officials. Thus, the Quezon project in the Philippines success in operating in an otherwise delicate area of the country reflects sustained investment by the project company in community welfare and relations. The critical distinction between the two failed coal projects in Thailand and the one coal project that is approaching commercial operations appears to be one of siting—the two failed project were located on beaches, the successful project on an industrial site.

Get good contracts in form, but be flexible in reality. Contracts are important for a range of reasons, including the fact that project finance is impossible without them. Yet, arranging appropriate and clear contractual rights is one thing—enforcing them rigidly is another. Every class of actor in the IPP casino has found it necessary or efficient to stretch beyond previously accepted boundaries. Governments have paid enormous sums for contracts that in hindsight were poorly structured. Arbitration panels have lowered damages or have overlooked contractual requirements in order to facilitate restitution. Some investors have deferred payments, changed fuels, refinanced debt, and maintained open lines of communication with offtakers in open default. Lenders have overlooked technical default on what seems to be a regular basis. The reality of contract renegotiation has led some to search for a "living and breathing" document, but that in itself is not a solution because formally flexible contracts may invite harmful changes and, in any case, are not attractive to the financial community.

Many investors approach renegotiation with dread and adopt a zero-sum attitude to the process. In fact, abandonment of contracts is rare, and outright expropriation is rarely the driving force for renegotiation. However, renegotiation of various types is common. Every case of successful full-blown renegotiation analyzed in this study involved, in practice, a give-and-take between investors and the host government. This process depends on reasonable behavior from both parties, but has been greatly facilitated

when investors identify reciprocal needs that can be met in a renegotiation. If the past is any barometer, such episodes are likely to persist—even for successful IPPs—because renegotiation is a sign of changing circumstances rather than a fundamental failure in the project concept.

Focus on fuel risk. The remarkable regularity with which fuel supply contributed to project outcomes across the country sample should be an enduring lesson from the first round of IPP investment. The successful "low-price" countries in Egypt, Mexico, and Thailand all relied on aggregated fuel purchases that require the electric utility to absorb the cost and political machinations required to obtain fuel from the country's oil and gas enterprise. (As such, these countries offer a cautionary tale regarding the limits of reform. Each country absorbed substantial risks in providing such arrangements for their IPPs; these arrangements are not likely sustainable if replicated on a large scale, yet moving past them is also difficult, as Mexico has discovered). By contrast, IPPs in India, Brazil, the Philippines, China, and Poland have often found themselves caught in the unforgiving politics of fuel markets. In each case the causes and contours of the problem were different, but all had in common the squeeze on the financial viability of private generators.

There is no universally valid strategy for managing fuel risk. When governments attempt to introduce new fuels into the electricity generation sector the outcomes are often particularly bad because these fuels are traded in thin markets and have properties (e.g., cost) that are quite different from the incumbents. The most successful example in our sample of 12 countries is Mexico—partly because of the consolidated fuel contracting system in that country and mainly because the new fuel (gas) had lower long-term and short-term costs than than the incumbent (oil). In most other countries, gas competed with coal or hydro—both of which usually have much lower short-term costs than gas. From the IPP's perspective, choosing the incumbent fuel is often safer, yet brings its own risks in countries like India and China where coal markets are unreliable and layered with non-transparent costs. In China, some IPPs relied on imported coal only to find it difficult to pass on the higher costs; in India none of the IPPs burns coal in part because none could get a reliable fuel allocation.

VI. Conclusion

This study set out to answer a basic question: What explains the variation in outcomes among private power plants built to supply electricity in developing countries? To answer this question, this study has examined a sample of twelve countries and thirty-three projects that offer variation along a series of key explanatory variables. The aim was to generate conclusions of general applicability in explaining the IPP experience, as well as some visions that can frame the future for such investment.

In explaining the IPP experience, this paper makes two broad arguments. First, a series of institutional and structural variables largely determine the risks that an IPP faces. These include broad factors that work at the level of countries, such as the investment climate and rules that govern the power sector. They also notably include

factors that are largely exogenous to the country's decision-making, such as macroeconomic contagion. The importance of these factors in setting the level of risk faced by projects suggests that broad efforts to strengthen public finance, adopt policies that dampen macroeconomic shocks, end corruption, and manage the power sector adeptly are crucial tasks for establishing self-sustaining and efficient electricity sectors.

However, these structural factors do not always dictate project outcomes. Even the factor that explains project stress more than all others—macroeconomic shock—has been weathered with a wide range of ultimate outcomes. However, the risk mitigation arsenal commonly deployed by investors, referred to as "risk engineering" in this paper, performed poorly in the face of stress. These arrangements have been animated by the desire to bind the hands of fickle government officials; in practice, they often do not work because most of these tools depend on a larger institutional infrastructure to be effective. These techniques are not unimportant, but excessive attention to them has eclipsed the other category of project factors that in fact explain much of the variation in outcomes. These include basic commercial management (such as attention to costs so that IPPs are less visible even when they appear to be more costly than rivals), careful structuring of incentives to hold up in the face of stress, transparency in project selection and allocation, and selectively engaging local partners.

These conclusions carry potentially important implications for key theoretical debates that accompanied the private infrastructure boom of the 1990s. Following on a growing body of literature,[287] the IPP experience suggests that the relationship between reform and private investment may be more antagonistic than originally assumed. In country after country, the winners from early reform attempts benefit from the persistence of an awkward status quo, neither fully private nor within the grasp of government. In areas other than the power sector, these actors have not only earned sizeable rents, but have also tended to be more confident in their ability to navigate the risks of this dual environment than purely private firms.

Despite these challenges, the study is more optimistic than the dismal predictions of the obsolescing bargain hypothesis. Although the self-help tools that multinational investors used in other areas—such as control over unique technology—are generally not available to the infrastructure investor, a large fraction of the IPPs subjected to severe stresses have nonetheless found it possible to manage the change in circumstances. They have deployed a wide range of strategic risk management tools, and their experiences could be useful in other infrastructure sectors, such as water services and transport, that face similar risks from high capital costs, long amortization periods, a context of uncertain regulation, broad public consumption, and a history of politicization.

Looking to the future, the study suggests that while the niche for classic IPPs may be smaller in the coming years than originally hoped in the 1990s, it appears likely that many of the challenges will remain the same. New investment will arrive with a new

[287] Joel S. Hellman, *Winners Take All: The Politics of Partial Reform in Postcommunist Transitions*, 50 WORLD POLITICS 203 (1998).

generation of lawyers, bankers, and developers ready to solve the challenges of the past. Already investors are looking again at countries that were among the worst for investors in the 1990s, such as Pakistan and Indonesia. It is crucial to focus on the sources of trouble and opportunity from the 1990s, lest the next wave repeat the same mistakes of the past. To this end, the study also offered a series of detailed implications for host governments and for investors.

The study suggests some areas that would benefit from further research. First, this work and others have suffered from the veil of secrecy that surrounds large infrastructure projects. The proxies for financial viability relied upon here can yield valuable insight. Nonetheless, tracking with precision the impact of government and investor behavior on the cost and profitability of projects would yield valuable new lessons. Second, the anatomy of dispute resolution is extraordinarily murky—effective dispute resolution is evaluated too often based on the subjective judgment of participants as seen in their behavior; if they seem "content" the problem is deemed solved, whereas if the dispute escalates, the problem is deemed unsolved. This method lacks a filter for the reasonableness of behavior by key stakeholders as they react to a range of incentives and goals exogenous to a particular project. Third, a wider base of statistical analysis that studies the relationship of particular risk management techniques to country characteristics is important to provide an effective foundation for continued work such as this paper.

Finally, and perhaps most importantly, this study highlights a methodology that facilitates focusing on project outcomes in a way that can produce generalizable findings. A crucial task for the literature on infrastructure investment is to tie causal factors to actual outcomes for projects in a systematic way. By adopting an intermediate approach between large statistical work and focused individual case studies (a so-called "medium N" study) this paper seeks to bridge that gap.

Annex 1: Project Details

Project Name	Country	Fuel	MW	Cost US$	$/MW[288]	COD	Foreign Sponsor	Local Sponsors
Termoceará	Brazil	Nat'l Gas	290MW	$100	$345	2001	MDU Resources	EBX Capital
Macaé	Brazil	Nat'l Gas	928MW	$730	$787	2001	El Paso Energy	--
Norte Fluminense	Brazil	Nat'l Gas	780MW	$887	$1137	2004	Electricite de France	--
Uruguaiana	Brazil	Nat'l Gas	600MW	$350	$583	2000	AES Corp.	--
Caña Brava	Brazil	Hydro	450MW	$426	$947	2002	Tractebel Energia	--
Shajiao C	China	Coal	1980MW	$1,870	$944	1996	CEPA → Mirant	Guangdong gov't
Meizhouwan	China	Coal	724MW	$755	$1043	2001	Intergen, El Paso, Lippo	--
Shandong Zhonghua	China	Coal	3000MW	$2,200	$733	2003	CLP, EDF	Shandong gov't
Sidi Krir	Egypt	Nat'l Gas	685MW	$418	$610	2002	Intergen	--
Suez	Egypt	Nat'l Gas	683MW	$340	$498	2003	EDF	--
Port Said	Egypt	Nat'l Gas	683MW	$338	$495	2002	EDF	--
GVK Jegurupadu	India	Nat'l Gas	216MW	$261	$1208	1996	CMS	GVK
Lanco Kondapalli	India	Nat'l Gas	250MW	$285	$1140	2000	CDC Globeleq	Lanco
Essar Power	India	Naphtha/Gas	515MW	$514	$998	1995	--	Essar Steel
CLP Paguthan	India	Naphtha/Gas	655MW	$734	$1121	1998	Powergen → CLP	--
PPN	India	Naphtha/Gas	330MW	$252	$764	2001	El Paso, PSEG, Marubeni	Reddy Group
ST-CMS	India	Coal	250MW	$320	$1280	2002	CMS	ST Power
IberAfrica	Kenya	Diesel	44MW	$65	$1477	1997	Union Fenosa	KPLC Pension
Tsavo	Kenya	Diesel	75MW	$85	$1133	2001	Cinergy, CDC, Wartsila, IFC	IPS (Agha Khan)
Monterrey III	Mexico	Nat'l Gas	1190MW	$610	$513	2001	Iberdrola	--
Rio Bravo II	Mexico	Nat'l Gas	568MW	$234	$412	2002	EDF	--
Merida III	Mexico	Nat'l Gas	530MW	$260	$491	2000	AES, Nichimen	Grupo Hermes
Navotas I	Phil.	Diesel	210MW	$40	$190	1991	CEPA → Mirant	--
Pagbilao	Phil.	Coal	700MW	$888	$1269	1996	CEPA → Mirant	--
Quezon	Phil.	Coal	460MW	$895	$1946	2000	Intergen, Ogden	PMR Resources
Casecnan	Phil.	Hydro	140MW	$495	$3536	2001	CalEnergy, Peter Kiewit	LA Prairie, San Lorenzo
Cavite	Phil.	Diesel	63MW	$22	$349	1995	CMS → Covanta	--
ENS	Poland	Nat'l Gas	116MW	$132	$1138	2000	Enron (Prisma)	JAC International
Elcho	Poland	Coal	220MW	$324	$1473	2003	PSEG	EC Chorzow
Eastern Power	Thailand	Nat'l Gas	350MW	$250	$714	2003	Marubeni	GMS
Independent Power	Thailand	Nat'l Gas	700MW	$369	$527	2000	Unocal, Westinghouse	Thai Oil
Gebze, Adapazari, Izmir	Turkey	Nat'l Gas	3860MW	$2000	$518	2002	Intergen	Enka
Trakya Elektrik	Turkey	Nat'l Gas	478MW	$600	$1255	1999	Enron (Prisma)	Gama

"MOU/Bid" = date project initiated via MOU or award in bidding process; "**PPA**" = date of PPA signing; **"COD"** = date of commercial operations.

[288] Note that cost per megawatt is not strictly comparable across projects. In broad terms, power plants designed for different fuel types (*e.g.*, coal, gas, oil, hydro) have entirely different cost components for construction and operations. Further differences reflect changes in input markets (equipment, technology, raw materials) over time, as well as the risk premia charged by lenders and equity holders for the project.

Annex II: Case Selection and Project Description

As part of the IPP study, the Program on Energy & Sustainable Development sponsored a series of country studies. These papers detail the basic contours of the IPP experience in each country, discuss the country factors identified in the research protocol. Additionally, each paper presents the universe of greenfield IPPs in the country, identifies the significant characteristics across which these projects vary, and selects a small number for individual examination. Each country study is available as a working paper at http://pesd.stanford.edu/ipps.

This section summarizes the basic experience and presents the project selection criteria for each country. The examination of projects in each country varies in the level of detail. Generally, the most detailed work was conducted in Brazil, China, Egypt, India, Kenya, the Philippines, and Thailand—countries in which field research was conducted. In these cases, a wide array of locally available sources of information, including local media and government records, and interviews with investors, project advisors and government officials, have been gathered.

In other cases, media and scholarly sources of information are relied upon, and are supported by stakeholder interviews where possible. In these cases available information may be limited. Additionally, several projects that are involved in ongoing disputes are covered. In these cases, where relations between government officials and project stakeholders may be very sensitive, the treatment in the IPP study is limited. Some of these studies may be updated if and when disputes are resolved.

Argentina.

Argentina privatized its electricity system in 1992, in one of the most successful reform efforts in the developing world, with generation, transmission and distribution unbundling and passing to private ownership. From 1992-2002, a private and fragmented generation market competed to sell electricity in a spot market in which the wholesale price of electricity declined from (US) $41/megawatt-hour in 1992 to $22/megawatt-hour in 1995, and average thermal power plant availability improved from 48 percent to nearly 70 percent. During this time there were 45 private power plants in Argentina, of which roughly 15 were greenfield projects, including both hydro and thermal (mostly natural gas) plants.

In 2002, Argentina faced a severe macroeconomic and political crisis, which reached a dramatic crescendo in January 2002, when the government abandoned the 10-year currency board that had pegged the peso to the dollar at 1:1. Subsequently, the government converted all infrastructure contracts to pesos, inviting an ongoing dispute with investors (and with the IMF) who faced a dramatic erosion in revenues. Almost thirty arbitration claims have been filed against Argentina (from all sectors). The private generation sector continues to sell electricity, and the two sides weave (or stumble) their way to a settlement.

No in-depth project studies were undertaken in Argentina. The determinants of outcomes for IPPs in Argentina are predominantly country-level factors, including the macroeconomic crisis of 2001-02. Most projects have faced the same challenges. Some variation has been

reported from local IPP investors converting debt to pesos prior to the crisis, which would allow them to weather the troubles relatively undisturbed.

Brazil.

Brazil followed the example set by Argentina and Chile in 1995, embarking on an ambitious reform of its electricity sector. The privatization ground to a halt due to lack of investor interest and political opposition, leaving most of the generation sector under state control. Between 1996 and 2003, generators operated in a multi-buyer, multi-seller environment, dominated by bilateral contracts between generators (public and private) and either distribution companies or large users. In 2003, the administration of President Luiz Inacio Lula da Silva announced a new model law for the wholesale electricity markets. This new model segregates the market into a regulated (distribution companies selling to captive consumers) and free (large users) segments. Sales to the regulated market can only be made via managed auctions at regular intervals prior to delivery of electricity. The new model has yet to reach full operations—the first auction for new capacity is scheduled for November 2005.

In addition to the halting progress of privatization and uncertain reform agenda, the major challenge has been to attract investment in thermal capacity into an electricity system dominated by hydro plants. Facing an energy shortage in the late 1990s, Brazil was forced to offer generous concessions to thermal IPPs that were contracted under a priority program. In Brazil's merit order dispatch system these plants suffered from poor utilization, and government entities that had been enlisted to provide support for these plants (notably Petrobras, the state oil and gas monopoly) became increasingly restive. Several arbitrations have arisen from thermal plants facing non-performance from key government counterparties or from consumers unhappy with the high cost of inflexible thermal projects.

Project selection in Brazil reflects two key variables. The first is fuel choice; in a hydro dominant system, it is important to select both thermal and hydro projects. The study examines a range of thermal projects (Termoceará, Macaé, Norte Fluminense, Uruguaiana), and one hydro project (Caña Brava) (the limited selection of hydro projects is discussed below). The second is the choice of offtaker and power sales arrangements; for thermal projects, special arrangements to attract investment included quasi-merchant projects with revenue guarantees (Termoceará, Macaé), sales to isolated systems, sales to state distribution companies (Uruguaiana) and pass-through arrangements with associated distribution companies (Norte Fluminense).

Termoceará. Termoceará is a 290MW natural gas-fired power plant in northern Brazil, near the city of Fortaleza, developed by MDU Resources, a United States utility, and EPX Capital, a Brazilian industrial firm. The plant was built on a quasi-merchant basis, intending to sell electricity in via the spot market and short-term contracts, but with a minimum revenue guarantee from Petrobras, which functions like a capacity payment, covering fixed costs and some level of returns to equityholders. The project was constructed by its sponsors on balance sheet. After commercial operations, corporate financing was obtained from United States Export-Import Bank and BNDES.

Originally developed during the electricity shortage of 2001-02 when spot prices were around $600/kWh, Termoceará reached commercial operations in late 2002, when spot prices had dropped to $18/kWh. In addition to low prices, gas shortage became a principal cause of problems for Termoceará—exacerbated by transmission bottlenecks that fell far short of demand when the two gas-fired projects in the region (the other was Endesa's Termofortaleza) were dispatched at high levels.

Since 2002, project sponsors have been engaged in an ongoing dispute with Petrobras, which was losing hundreds of millions of dollars covering the minimum revenue guarantee. On January 13, 2005, Petrobras obtained an order in Brazilian court providing for the deposit of monthly capacity payments into a court account until the dispute was resolved. MPX successfully litigated this decision and secured a reversal in trial court and on appeal, on Feb. 17, 2005. In the end, Termoceará's sponsors appear to have exited the project in good shape. Final sale price to Petrobras was $137 million (including the total assumption of indebtedness), on a project whose original cost was $100.

<u>Macaé</u>. El Paso's Macaé project is another quasi-merchant project developed along similar lines as Termoceará. The 928 megawatt plant fires on gas from the nearby Campos Basin field provided by Petrobras. As with all three of the merchant plants, Macaé has run into trouble with Petrobras when spot market prices fell drastically. While Petrobras has purchased the other two projects outright, discussions regarding a purchase of Macaé continued alongside an arbitration brought by Petrobras to alter the original contract. The variation in outcomes may reflect the scale of Macaé (900+ megawatts as opposed to 290 megawatts for Termoceará) which makes the project both vastly more expensive and more profitable. Additionally, as Brazil again faces a shortage of electricity in the near term, a facility like Macaé may be well-positioned to operate profitably.

<u>Norte Fluminense</u>. Electricité de France's ("EdF") Norte Fluminense project is one of four natural-gas fired "self-dealing" projects developed in Brazil as part of the Priority Thermal Program. The 780 megawatt power plant sells all of its electricity under long term contract to Light, the distributor on Rio that is also controlled by EdF. Under pressure to resolve the logjam that was keeping thermal plants from closing in Brazil as the hydro shortage loomed, the government authorized four projects with different distribution companies—prices would be fully passed through, the plants could declare themselves "inflexible" at a level to cover take-or-pay clauses in gas contracts, and there was no limit on capacity. These projects have enjoyed stable operating histories, largely because of the relationship with their offtaker.

Norte Fluminense has been a positive investment for EdF, and is a small enough share of total generation that has not affected retail tariffs in Rio substantially. This outcome is in contrast to the case to Iberdrola's Termopernambuco, where the impact on retail tariffs has been large enough to invite consumer opposition; the 520 megawatt project comprises such a large proportion of generation costs that the plant has caused a 17% increase in the power tariff in the Brazilian state of Pernambuco. The price of power generated by Termopernambuco (R$57.51/MWh) is almost twice the price on existing energy auctions (R$37.83/MWh). In response to a wave of public interest lawsuits, a federal judge ordered Brazilian regulator ANEEL to reduce from 24.4% to 7.4% Celpe's requested tariff increase to cover the costs of

purchasing power from Termopernambuco. The resolution of ongoing litigation around Termopernambuco may carry implications for the other self-dealing projects, including Norte Fluminense.

Uruguaiana. AES's Uruguaiana was the first private natural gas-fired project to be developed in Brazil, with a 1996 bidding conducted by CEEE a then-public distribution company. CEEE has since split into two private companies (Rio Grand Energia, AES Sul) and one still-public arm (CEEE). Uruguaiana's original PPA with CEEE is now split ratably between the three successor firms. In contrast, to the other self-dealing projects, Uruguaiana sells to three very different offtakers, and sources gas from Argentina. Gas supply has been a problem, particularly during the winter. Often Uruguaiana has solved this problem by buying power on the spot market to cover its PPA obligations.

Caña Brava. The universe of greenfield hydroelectric projects in Brazil that fall within the IPP study is small. Most new hydro projects were developed to sell to captive users or for self-supply. The Caña Brava project, developed by the Brazilian subsidiary of Belgium's Trachtebel ("Tractebel Energia"), is an exception. Caña Brava sells electricity under long-term contract to Gerasul, a generation company also partly owned by Tractebel Energia.

Under the market structure for electricity generation that prevailed from 1995–2003, the experience of developed hydroelectric power plants in Brazil is radically different than developing thermal projects. In the hydro system, financial settlement (paying contract prices) has been entirely divorced from physical settlement (dispatching electricity). In practice, this means that hydroelectric facilities market their electricity independently, but deliver their electricity collectively, in effect sharing hydrology risk with the entire system. Once a hydroelectric facility reaches commercial operations, project returns are stable and predictable.

Under the new market structure for electricity generation, although the operation of the hydroelectric system will remain in place, the commercial environment will be radically different. Hydro facilities will sell electricity to a regulated power pool composed of all of the distribution companies in the country. This new model is not fully established yet, and substantial uncertainties remain concerning how auctions and financial settlement will be conducted. Nonetheless, existing generators have been unenthusiastic. Prices in the first auctions have been below long-run marginal cost. Perhaps more importantly, the management of offtake risk in the new power pool is unclear; generators are unsure about where payment responsibility lies (whether in the pool itself or some central authority, or directly with distribution companies), and have little means of pricing this risk.

China.

China was an early entrant into the IPP market, starting with a joint venture between Hong Kong-based China Light & Power and the Guangdong provincial government to build a nuclear facility in the 1980s. This opened the door for the first true IPP—Hopewell Holding's Shajiao B project in Shenzhen. The bulk of the Chinese IPP market blossomed during the mid-1990s, with almost US$4 billion worth of IPP investment closing in 1997 alone. Just as precipitously, the market bottomed out, and in 2000 no project reached financial close.

In China, IPPs signed long term yuan-denominated offtake agreements with provincial electricity boards. In this decentralized environment, outcomes of the IPP program have been generally poor for investors. Investors have had a very difficult time facing numerous tariff reductions and other changes to the original contract terms. On the other hand, some might argue that the government got what it wanted—FDI to help ride out a tight monetary period in the early 1990s, and technology and management transfer from sophisticated multinationals. Increasingly, the Chinese markets have returned to liquidity and quasi-state spin-offs of the now defunct national power corporation have risen to assume a dominant role in the generation sector.

The project sample in China focuses on the large coal fired projects that represent the vast majority of IPPs in the country. Within this group, project selection reflects two key variables. The first is ownership structure; in China many projects included entities affiliated with local governments—the study includes two such projects (Shajiao C, Shandong Zhonghua) and one wholly-foreign-owned project (Miezhouwan). The second is location; the economies of Fujian (Miezhouwan), Guangdong (Shajiao C) and Shandong (Shandong Zhonghua) have had different trajectories during the relevant period.

Shajiao C. The 1980 megawatt coal-fired Shajiao C project was developed by Gordon Wu's Hong Kong based CEPA, and sold to Southern Company (Mirant) as part of the latter's acquisition of CEPA's IPP portfolio (except for the Indonesian assets). The project was set up as a joint venture between local government entities that controlled 60% of the project, with a minority holding for the foreigners. Investment outcomes for the project have been positive. Both CEPA and later Mirant have exited Shajiao C for unrelated reasons, reporting profits on the sale. This positive performance is supported by two factors. First, Guandong province has enjoyed robust economic growth during the operations of Shajiao C, with steadily rising electricity demand. Second, a clause in the joint venture agreement between the foreign and local sponsors required the local firms (essentially arms of the Guandong provincial government) to make whole any losses to the foreigner from adverse regulatory decisions.

Miezhouwan. Intergen's Miezhouwan project was the first wholly-foreign owned IPP in China. The 724 megawatt coal-fired project was built in Fujian province. The Fujian grid is isolated from the rest of the Chinese grid. Additionally, by the time Miezhouwan came online in 2001, previously optimistic forecasts of the electricity supply-demand balance had withered due in part to aggressive build-out of capacity and in part to a generous hydrological year in 2001. Miezhouwan was already more expensive than its competitors in the Fujian market, and with little demand to service, faced problems almost immediately when local authorities refused to acknowledge commercial operations.

The project's sponsors have since made several adjustments in the course of renegotiating the power sales agreement, including refinancing with domestic banks and changing fuel supply from Indonesian to Chinese coal suppliers. Nonetheless, the Miezhouwan model is not replicable for future investors. As demand continues to grow in Fujian, the project may deliver much needed electricity at a lower renegotiated cost. The cost to Fujian or China in terms of

deterring further investment is not yet clear—for now the country seems able to meet its needs internally.

Shandong Zhonghua. This 3000 megawatt project was developed jointly by Electricité de France, China Light & Power, and arms of the Shandong provincial government. The facility contains both brownfield and greenfield units, the latter financed in part by revenue from the operating units. Shandong province operates, like Fujian, an isolated electricity grid, meaning that supply-demand imbalances cannot smoothed across the country. Shandong experienced a period of oversupply in its electricity market in 2004, later than most of China. Outcomes for Shandong Zhonghua followed suit.

Like other projects in China, Shandong Zhonghua has seen its fortunes rise and fall with the supply-demand balance. In this case, problems appeared in the form of lower than expected tariff increases which failed to cover rising coal costs. CLP annual reports indicate that these problems have reduced returns on the project, in early 2005 they were optimistic that disagreements with Shandong officials would be resolved soon.

Egypt.

Egypt opened its generation sector to private participation in 1996, with a law that laid the foundations for a competitive bidding process for three IPPs that were awarded in 1998 and 1999. All three projects sell electricity under long term contract with Egypt's national utility holding company, EEHC, that are backed with a Central Bank guarantee. Fuel for the projects, all of which fire on natural gas, is provided by the Egyptian gas monopoly at a substantial discount from market rates. The Egyptian IPPs are occasionally cited as the most competitive in the world—for example, InterGen's (now Globeleq) Sidi Krir project bid a price of US$0.0254 per kWh. Turbulence in Egypt's IPP arrangements has arrived with a 2002 economic downturn and subsequent devaluation of the Egyptian pound from 3.2 to 6 pounds against the US dollar. The Egyptian government has soured somewhat on these projects as they grow increasingly expensive, and has prohibited the denomination or indexation of infrastructure contracts.

The project sample in Egypt contains all three operating IPPs. These projects are structured substantially similarly. Variation exists along only a few factors. First, Sidi Krir was sponsored by a major US power company (Intergen), while Suez and Port Said were sponsored by the French utility Electricité de France. Second, Sidi Krir obtained debt finance entirely from commercial banks in Egypt and in Europe, while the EdF projects turned to multilateral sources (the IFC) for substantial debt financing.

Sidi Krir. This 682.5 megawatt natural gas-fired power plant was the first IPP in Egypt. A competitive bidding process in 1996 generated substantial interest, with more than fifty firms applying for pre-qualification. The project was awarded in February 1998 to a consortium consisting of Intergen and Edison Mission Energy from the United States. The winning bid was US$0.0254/kWh, which was among the lowest electricity prices for an IPP in the developing world. The project fired on domestically produced natural gas that was supplied at a healthy discount by the Egyptian state gas monopoly. Additionally, the project debt is wholly private—domestic Egyptian banks provided most of the financing on a project basis, albeit denominated

in dollars. International commercial banks provided the rest of the debt, with no involvement from multilateral or bilateral lenders. Intergen and Edison Mission sold their interests in Sidi Krir in 2005, apparently as part of global restructuring of their power business, and not as a reflection of troubles in the project itself.

Suez & Port Said. These projects, Egypt's second and third IPPs, are each 683 megawatt natural gas fired power plants awarded to Electricite de France. The projects were awarded and developed along substantially similar lines as Sidi Krir. The significant difference was the EdF sourced its lending from the IFC and a syndicate of international banks and institutional investors. This difference reportedly reflects the fact that by the time the projects sought financing, Egyptian officials lacked the appetite to mobilize additional domestic lending for power plants. At the same time, European banks in the delicate financial environment of 1998 were unwilling to undertake the entire project without some involvement from the IFC or other prominent international financial institution.

Outcomes for all three projects have been positive. No major disruptions in construction, operations or payment have been reported. The power sales contracts have weathered a macroeconomic shock intact, and continue to generate revenue. The only negative outcome identified was that sponsors for each project had invested at least partly on the assumption that Egypt would continue to open investment opportunities. Egypt did have plans to solicit additional projects (up to a total of fifteen IPPs), but reversed course after the cost of the projects spiraled with the devaluation.

Outcomes for Egypt have also been positive. The cost of the payments to the IPPs have almost doubled with the 2001 devaluation of the Egyptian pound, and Egyptian officials now express some dissatisfaction with the projects as being too expensive. Nonetheless, because (i) the original bids were very competitive, (ii) the IPP sector remains small, and payments manageable even if unexpectedly high, and (iii) electricity is being generated, the experience seems a positive one for Egypt. Additionally, although the government has turned to state and multilateral sources of capital for new development, the early IPP investments have been conducted in a manner that provided valuable experience to the country, and have not unduly prejudiced the prospects for future investment.

India.

The IPP experience in India has been infamous for the long shadow cast by Enron's Dabhol project—a two-phase 2000 megawatt+ naphtha and natural gas-fired facility in Maharashtra that has faced a bitter and protracted dispute. India began its IPP program with amendments to its electricity law in 1991, allowing private participation in generation, and stimulating a wave of experimentation by state governments, who share authority over electricity with the central government in India's federal system. Of the hundreds of MOU's that were signed, however, only slightly more than twenty projects ever came online, including four of the eight "fast-track" projects (of which Dabhol was one). IPPs in India signed long term, dollar indexed PPAs with (largely bankrupt) state electricity boards, and have generally fired on a range of fossil fuels (including lignite, distillate oil, naphtha) and natural gas. Outcomes for IPPs in India vary significantly across states, depending on the financial health of the SEB and the

particular politics of electricity in each state. The evolution of primary fuel markets has also been an important determinant in the IPP experience—often providing leverage for the government to pressure projects to change their terms. Our work in India has focused on the experience of projects in Andhra Pradesh and Gujarat.

The project sample in India consists of four projects—two each in Andhra Pradesh and Gujarat. States were selected for (i) having more than one IPP, (ii) exhibiting variation in the ownership structures in the IPP sector, and (iii) exhibiting variation in the reform of the electricity sector. Andhra Pradesh was an early and relatively successful reformer in the electricity sector, and has IPPs that span all three regulatory regimes for IPPs (fast track, cost bidding, tariff bidding). All of the IPPs in Andhra Pradesh are foreign-local partnerships and fire on a combination of naphtha and natural gas from state owned gas companies. The principal variation is between the regulatory regime: the project examines both GVK Jegurupadu, an early "fast-track" project, and Lanco Kondapalli, a later project that was competitively bid on the basis of tariff.

Gujarat is a heavily industrial state and was a late reformer in the electricity sector. IPPs in Gujarat were bid out on the basis of cost. They burn natural gas that is sourced from local private companies, and exhibit variation in their power sales arrangements. The project examines China Light & Power's Paguthan IPP (a currently wholly-foreign owned project that sells electricity solely to the state electricity board), and Essar Power (a locally developed project that devotes a portion of its power sales to self-consumption).

In addition, we have drawn on the extensive literature surrounding the Dabhol project in Maharashtra, and have drawn on public sources (including local media and SEC failings) in tracking from afar an ongoing dispute in Tamil Nadu—including recent reports of improving relations and a potential settlement between the IPPs and the host government. Although detailed case studies were not possible in these cases, we include particular examples in our overall analysis where possible.

GVK Jegurupadu. The 216 megawatt Jegurupadu project, sponsored by GVK Industries and CMS Energy, was a "fast-track" project in India, developed under the 1991 amendments to India's electricity law. The project was awarded via negotiation and developed by GVK and CMS with support from a central government counter-guarantee, escrow facilities for payment from its state offtaker, and loans and equity investment from the IFC and ADB. Like other projects in India, Jegurupadu has faced a difficult operating environment—the PPA was renegotiated twice before commercial operations to correct awkward provisions in the first version, and as part of securing the central government counter-guarantee.

Jegurupadu has been paid under the terms of the PPA, although with some ongoing disputes. With a tariff set on a cost-plus basis, the project came in above cost, and AP Transco has continued to pay according to contract cost while the CEA, which is supposed to approve project costs, has dragged its feet. Additionally returns have been eroded by difficulties keeping operating costs within the 2% pass-through provided in the PPA. Nonetheless, the investor outcomes have been positive—these disputes appear to concern marginal amounts of money. The tariff formula is calculated to provide a 16% rate-of-return at 68.5% PLF with incentives for

higher load factors. Even with ongoing disputes, the plant has often run at or above 85% and should be performing well financially. CMS has now exited the project, which is controlled by GVK.

Lanco Kondapalli. The 330 megawatt naphtha and natural gas-fired Kondapalli plant is a subsequent Andhra Pradesh project, developed via competitive bidding on the basis of final tariff. Kondapalli is the only one of six tariff-bid projects in Andhra Pradesh to reach commercial operations. Shortly after the projects were awarded, naphtha prices were deregulated and rose dramatically. After securing financing prior to a contractual deadline for these plants and covering cost of converting to natural gas, Kondapalli came online in 2000.

Like Jegurupadu, the investorment outcome for Kondapalli has been positive, even through difficulties. The plant has been involved in a series of disputes with state offtaker AP Transco regarding sharing the benefits of below-cost construction and regarding state testing to confirm the rated capacity of the plant. Nonetheless, sponsors report a positive investment in the project, and not other public information suggests further problems.

CLP Paguthan. Paguthan was developed in the Indian state of Gujarat by local Indian developer Torrent Group, along with Powergen of England. China Light & Power acquired Powergen's portfolio of projects in Asia, including Paguthan. The 655 megawatt natural gas-fired plant has been one of the first plants in India (along with Essar Power, also in Gujarat) to secure gas supply from a private firm, with firm delivery requirements. The relationship with state offtaker Gujarat Electricity Board has been rocky—the tariff for Paguthan has been renegotiated on several occasions, forcing sponsors to make adjustments wherever possible to earn a return. Nonetheless, the project seems to have provided acceptable returns for CLP.

Essar Power. The 515 megawatt naphtha and natural gas-fired Essar Power plant was developed by Essar, a domestic Gujarati firm that originally aimed to provide electricity only for its steel plant. At the request of the Gujarat Electricity Board, the original plant was expanded from 215 to 515 megawatts. The project has struggled to source natural gas in the uncertain Indian gas markets, often running partly on expensive naphtha. Essar has remained stable through troubles in the naphtha market, the transition to gas, and others, in part by always having a dedicated offtaker for at least some of its load. In particular, when gas was scarce and Essar ran primarily on naphtha, steel prices were high and the project could operate profitably by powering the steel plant; when steel prices fell, the decline coincided with Essar Power's new private gas contract to source gas from the new Petronet LNG terminal.

The Tamil Nadu IPPs. Tamil Nadu has been a stark counterexample to the relative successes of Gujarat and Andhra Pradesh. Five projects have been developed here to sell electricity to the Tamil Nadu Electricity Board. These five projects exhibit a diverse mix of fuel choices, technology, local and foreign investors and strategies. In 2001, when all five of the projects had come online, the Tamil Nadu Electricity Board ("TNEB") announced that it would pay only 2.25 rupees/kWh to each plant, which was below contracted tariffs for each of the projects. 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 at least $150 million.

In general terms, project outcomes in Tamil Nadu have been negative for both investors and for hosts. Despite efforts to resolve the issue on both sides, investors have likely paid a heavy price for four years of underpayment. For the government, even reduced payments have been difficult, and the prospect of repaying the outstanding arrears will have a substantial impact on the state's balance sheet. The core problem for TNEB is its inability to collect revenue sufficient to cover generation costs. Nonetheless, contracting for IPP power that exceeds its ability to pay has prejudiced the state's ability to continue attracting sustainable investment in the future. Additionally, the plants often appear to be relatively expensive—either firing on naphtha (PPN Power) or with relatively high fixed costs (ST-CMS) among Indian IPPs.

Kenya.

Kenya stands out in our country sample for having developed IPPs within an electricity sector comprising only 1200 megawatts of generating capacity and in which only 15% of the population has access to electricity. For much of the 1990s, the country faced an embargo from the international aid and finance community reflecting a poor record on corruption and democratic governance. In this environment, private finance was relied upon as the only alternative. IPPs arrived in Kenya in two phases, beginning in 1996 with the passage of a law authorizing private participation in the generation sector. The first tender, which actually began in 1995, produced two BOO projects (OrPower4 and Tsavo Power) along a classic IPP model—20 year PPAs for energy sales to a single state utility, with minimum offtake provisions and elaborate security mechanisms, but conspicuously with no sovereign guarantee (Tsavo Power became the first IPP to be financed on a project basis in East Africa without a guarantee as credit support for the offtaker; OrPower4 has not secured financing yet).

Because these projects were slow in progressing from the original tender in 1995 to commercial operations for Tsavo in 2001, Kenya contracted two "stop-gap" IPPs for a total of 90 megawatts. These projects had only seven year contracts and, because of a requirement to come online within 11 months of signing the PPA, were financed by the developers on balance-sheet. Currently, government officials report mixed feelings with the IPP experience, mainly citing the adverse impact on the balance sheet of KPLC. There has been some public controversy surrounding concerns of corruption in some of the projects. Investors in some cases remain interested in long term investment in Kenya, but have also lost interest and exited in other cases.

The project sample in Kenya comprises two cases, one from each regulatory framework.

Tsavo. Sponsored by Cinergy-IPS, Wartsila, and the International Finance Corporation, this 75 megawatt diesel project was originally tendered in 1995, yet reached commercial operations only in 2001 due to delays in obtaining financing. These difficulties reflected, in part, the riskiness of investment in Kenya, which for much of the 1990s faced an aid embargo because of poor record on corruption and democracy, and the fact that the government did not extend sovereign guarantees for its IPPs.

Tsavo appears to be a positive experience for investors. Although the IPP has faced pressure from government officials to lower its tariff, these efforts have been resisted due to a

combination of several factors. First, the plant was awarded through an auction conducted according to international competitive bidding guidelines, although only three firms submitted bids. Second, Tsavo's tariff is competitive with those of the incumbent state-utility KenGen. Third, effective selection of partners; the IFC has played a part in deterring government pressure, and IPS is an arm of the regional Agha Khan Foundation that has operated in Kenya for decades. Finally, Tsavo is the only IPP to establish a community development fund in Kenya.

IberAfrica. IberAfrica is a 44 megawatt diesel-fired project developed by Union Fenosa of Spain with additional investment (loans and equity) from the KPLC Pension Fund (KPLC is the state-owned holding company for the electricity sector). As a "stop-gap" IPP brought on to forestall an electricity shortage, IberAfrica was financed on balance sheet by its sponsors, and reached commercial operations within a year of being awarded. IberAfrica is an interesting study in cost management. Like the other stop-gap project, Westmont, IberAfrica is expensive, a fact that reflects the short contract duration (7 years), the balance sheet financing, and the lack of a sovereign guarantee. Nonetheless, Westmont cost \$20 million for 46 megawatt of capacity, while IberAfrica cost \$65 million for 56 megawatt of capacity (mostly a reflection of technology and siting differences). However, unlike Westmont (a barge-mounted diesel peaking facility), which saw its per/kWh tariff spiral far above the rest of the generation sector when hydrological conditions returned to normal and thermal units were scaled back, IberAfrica (a land-based diesel baseload facility) reduced its capacity payment twice, by 30% and then by an additional 11%, and remained at a more reasonable level. Westmont has since departed the country after failing to agree on terms for a new contract, while IberAfrica has secured a new 15 year PPA, with a capacity fee 50% lower than that for the first contract.

Malaysia.

Malaysia entered the IPP market shortly after the Philippines, following mounting troubles in its electric power utility in the early 1990s. The 13+ Malaysian IPPs, which were predominantly large natural gas-fired projects, sold their output under long term ringgit-denominated contracts to Tenaga Nasional Berhad, the national utility. Most of the projects were arranged in a round of investment during 1993-94, and were not competitively bid, but rather allocated in a selective tender or negotiated directly, resulting in higher tariffs than Thailand's competitive projects, and handsome profits for the sponsors. Unlike most other countries, which involved substantial participation from US and European utilities, the project developers in Malaysia were exclusively Malaysian firms, while capital was sourced almost entirely from domestic markets, including state pension funds and other institutional investors. The Malaysian IPPs faced some pressure during the Asian financial crisis, but available information suggests that the contracts were not renegotiated and profits remained healthy. Many of the original IPP sponsors in Malaysia have been among the most profitable companies in the country, and continue to develop projects there.

No in-depth project studies were undertaken in Malaysia.

Mexico.

Mexico followed the South-East Asian model for private electricity investment, opening its generation sector to investment in 1992 under a single-buyer model in which IPPs would sell electricity to the Comisión Federal de Electricidad ("CFE"), an integrated national electricity utility. The first BOT project—Merida III—was awarded to AES over eighteen other bidders at a price of $0.03/kWh, lower than CFE's grid rate of $0.04-06/kWh at the time. Since Merida III, twelve other IPPs have reached commercial operations in Mexico. During this time, CFE has maintained a strong payment record and there have been no major contractual disputes or other challenges. Of two looming issues in the Mexican IPP sector, one appears to have been resolved. In April 2005 the Mexican Supreme Court upheld against constitutional challenge the contracts between CFE and its IPPs, which by now account for 20% of generating capacity. Still pending, however, are questions regarding the sustainability of the Pidiregas scheme through which CFE has underwritten the BOT contracts. This mechanism is essentially a guarantee that imposes substantial contingent liabilities on CFE—liabilities that are often kept off-book. Doubts have begun to percolate regarding the ability of the loss-generating state utility to continue amassing exposure to its IPP obligations.

IPPs in Mexico are all natural gas-fired, combined-cycle, BOO projects sponsored by foreign firms, though occasionally in partnership with local companies. Project selection in Mexico reflects only two key variables: the investor composition (foreign/local), and the evolving regulatory regime. Three distinct models for IPPs are observed in Mexico, with differences revolving around the fuel supply and exit/termination provisions. The project sample in Mexico includes three projects: one project from each regulatory regime, and one project that includes a local partner.

Mérida III. Mérida III, the first IPP and first BOO contract in Mexico after the 1992 law, is a 484 megawatt combined-cycle, gas-fired power generation facility, awarded to AES Mérida III, among a pool of 19 bidders. The lead sponsor is AES Corp., along with Nichimen Corp. (Japan), and Mexico's Grupo Hermes, a Monterrey-based industrial group which services the energy, automotive and service sectors. AES and Nichimen (but not Grupo Hermes) established AES Mérida III, to operate the plant after CFE awarded the PPA in February 1997. The project was built by Westinghouse under a turnkey contract and started operations in June 2000. The 25-year PPA with CFE provided for the sale of electricity at a price of less than 3 cents/kwh, below the subsidized SOE power tariff of 4-5-6 cents/kWh at the time of the bidding. Natural gas is supplied by CFE, which purchases the gas from privately owned and operated Mayakán Pipeline.

Despite some problems during construction due to turbine shortages in 1995, Mérida III is, like other Mexican IPPs, a success for both investors and for the government. The fundamental contracts have been stable and performed without any apparent dispute since the project was awarded. Prices are low, and the introduction of natural gas with IPPs in Mexico has facilitated a move away from old, dirty and inefficient oil-fired plants. Part of this favorable evaluation reflects the lack of any significant disruption in Mexico during the late 1990s. Potential problems in the Mexican IPP sector, including the costly Pidiregas program, inconsistent fuel contracts that place later plants at some disadvantage, and persistent problems in larger power sector reform (including non-transparent dispatch and highly subsidized tariffs), have not been tested.

Río Bravo II. Río Bravo II is a 495 megawatt natural gas-fired, combined cycle power plant developed by Electricite de France, next to two other EDF projects (Río Bravo III and IV). Operation and maintenance of the plant is handled by a 100%-EDF owned subsidiary that manages and operates all EDF Int'l plants. EDF is a major player in Mexico's energy sector, with interests in five combined-cycle plants totaling 2230 megawatt, or $1280 million in investment, and a 56 km-pipeline for natural gas (410,000 MM btu/day) connected to the border with the United States,

Rio Bravo II sells its output to CFE under a 27-year PPA based on an annual plant load factor of 80%. The fuel is provided by CFE, as initially arranged in the contract. The project had a cost of $234 million, with IFC support comprising $50 million in "A" Loan, $110 million in "B" Loan and $5 million in "C" Loan facilities.

Monterrey III. Monterrey III is a 1,140 megawatt combined cycle power plant entirely owned by Iberdrola of Spain, with additional participation from Alstom (operations) and financing from the IADB. Monterrey III was developed in two phases, with additional capacity being installed under different schemes authorized by the IPP law. In its initial phase, Iberdrola requested CRE authorization to install 570 megawatt capacity (under the IPP scheme), with the output to be sold to CFE under a 25-year PPA. Because the bidding documents and the PPA allow incorporating additional capacity for self-supply or contract with third parties, Iberdrola developed an additional 620 megawatt for sale to the local industry in Monterrey via bilateral sales contracts.

Monterrey III contributes more than 1,000 megawatt of private generation to the Mexican grid, which is particularly critical in Monterrey, one of the most industrialized cities in the country. The project also utilizes the most efficient and environmentally-friendly technology in the country, and is selling electricity at extremely low tariffs. At the same time, Monterrey seems to be performing well for investors; Iberdrola's sales in Mexico increased by 64% thanks to the Monterrey project, and the company plans an investment in Mexican power generation of US$3 billion from 2001-2006.

The Philippines.

The Philippines entered the IPP market early, with a 1988 presidential decree authorizing private investment in the generation sector. Major investment in IPPs occurred in response to a 1991-93 electricity crisis that saw rolling blackouts of 12-14 hours per day, up to 300 days per year. The 40+ IPPs that were developed in the Philippines proceeded in three broad stages: first, a series of "crisis" plants with shorter (5-12 year) contracts and usually fired on oil or diesel; second, a group of big baseload coal plants with longer (20-25 year) contracts; and finally, a series of natural gas-fired and hydro plants that reached operations between 1998 and 2001. The major hurdle in the sector came with the Asian financial crisis, which precipitated (among other troubles) high electricity prices, deteriorating fiscal stability in the national books, and public dissatisfaction that often focused on the IPPs whose contracts stood out in sharp relief against the hidden subsidies and soft budgets of the state dominated system. In 2001-02, in response to these public concerns, a government committee was appointed to review the IPP contracts. A

widely publicized renegotiation effort followed, however, contracts were widely honored in this process and investors remain largely pleased with their experience in the country.

The Philippines IPPs are perhaps the most diverse among the countries in the IPP study, exhibiting variation in fuel sources, investor composition, contract type and duration, extension of sovereign credit support, and method of solicitation. Project selection in the Philippines reflects three variables: fuel choice, regulatory regime, and choice of offtaker. The project sample consists of two of the early "emergency" plants (Navotas I and Cavite) and three prototypical long-term IPPs (Pagbilao, Quezon and Casecnan).

Navotas I. Developed by Hong Kong-based CEPA Navotas I was the first IPP in the Philippines, with a 10-year energy conversion agreement with Napocor backed a full performance undertaking. This project came online in 1991, and was the only private plant to begin delivering power until 1993, when the country was deep into the power crisis and brought a number of smaller diesel fired units online. Designed as a peaking facility, this diesel-fired plant often ran as baseload during the crisis, before being throttled back by the mid-1990s. Although firing on expensive diesel oil, and utilized at very low levels for most of the decade, Navotas was paid as per the original contract consistently. Outcomes for the Philippines have also been positive, as the country gained new generating capacity to help avert the looming crisis and laid the foundation for further investment.

Pagbilao. In 1991, CEPA began three years of negotiations that culminated in the 1994 signing of another ECA for the 700 megawatt Pagbilao coal-fired plant. Like Navotas I, Pagbilao was awarded through a bidding process (albeit with only two bids submitted), and also became a blueprint for future IPPs in the Philippines. So far as our research has indicated, this project has suffered only one major dispute. In 1996, although the plant had been constructed on time (and below cost), Napocor had not completed the transmission line to connect the plant to the grid, delaying commercial operations by several months. CEPA's claim for lost revenue reached $100 million before the dispute was resolved by extending the PPA by 4 years, from 25 to 29 years. Additionally, there have been some problems regarding the reliability of fuel delivery from Napocor, but given the overall performance, these do not appear to be serious.

The financial performance of this project appears to be highly successful. Like many of the Philippines IPPs, project revenues were heavily concentrated in US dollar denominated capacity payments, in this case 95% of revenue was from capacity payments. A recent IFC study of the project suggests a 17.5% internal rate of return over the life of the project, although acknowledges the possibility of much higher returns. Given Mirant's leveraging of the overnomination clause in the contracts for each of its plants, its additional sales via the marketing agreement with Napocor, and the remarkable profitability reported in the Philippine business press, it is likely that actual returns have been higher than 17.5%.

Quezon. The Quezon plant is a 460 megawatt coal-fired facility, developed by PRM Power, a local consulting group, along with Intergen and Ogden (now Covanta) from the United States. The project is connected to the national grid via a 31-kilometer transmission line built and owned by the project sponsors. The plant uses standard coal-fired steam generator technology and has been outfitted with extensive emissions abatement equipment. Although

relatively expensive in terms of cost/MW of installed capacity, Quezon helped expand the share of coal in the Philippine electricity sector, and pioneered a range of firsts for project finance in the country—the project was the first IPP in the Philippines to be financed without any sovereign guarantee and solely on the credit of its offtaker (Meralco), and was also the first to access international capital markets, with a $215 million bond offering in the US after financial close.

Quezon has endured stress due to poor technical performance in the early years of operations, disputes with its offtaker Meralco, and has seen several provisions of project contracts renegotiated. Nonetheless, the project has serviced its debt, and has maintained a healthy credit rating for its bonds. Project sponsors and managers have expressed satisfaction with the project's performance. Equity turnover in the project (Intergen's recent sale of its share) seems motivated by company-wide strategic decisions and not to reflect on any single project. Quezon's original sponsors (PRM Power, now GN Power) are developing another project in the Philippines.

Casecnan. This BOT project, a rare unsolicited project among IPPs in the Philippines, was developed by CalEnergy in cooperation with Peter Kiewit Sons, Ltd., which together held 70% of project equity. Additionally, two local partners, LA Prairie Group Contractors and San Lorenzo Ruiz Builders and Developers, together held 30% of project equity. Project development began in 1994 with a PPA signed between the National Irrigation Administratoin ("NIA") and CalEnergy, followed by financial close in 1995, but the project did not come online until 2001, due in part to a dispute with the original EPC contractor, Hanbo, a South Korean firm that declared bankruptcy in the midst of construction.

Casecnan consists of a power plant producing 140 megawatts of electricity as well as a system that delivers irrigation water from the dam. NIA is the offtaker for both irrigation water and electricity, which is sold to Napocor). NIA's obligations under the PPA are backed by a full performance undertaking from the Philippine Central Bank. Power sales arrangements call for NIA to purchase 100% of the power actually generated by the plant, on a take-or-pay basis. Capacity payments, which are entirely denominated in US dollars, amount to roughly 70% of project revenue, while energy payments were expected to contribute the remaining 30%. Total project cost is estimated at $495 million. Casecnan was financed on a project basis, with $371.5 million of debt being raised in the 144A bond market, to complement $124 million of equity contribution.

Scheduled to come on stream in 2002, the Casecnan project lacked any operating history when it was evaluated in the IAC Review. However, the report found that the plant had the highest levelized cost of any IPP and that the guaranteed flow 801.9 million m^3/year of water made no sense because the rivers did not deliver that much water. For its part, Casecnan had been frustrated by NIA's refusal to reimburse the costs of taxes paid by the company on behalf of NIA and reimbursable under the contract arrangements. Casecnan filed a notice of arbitration before the ICC in August 2002, although the disputes were eventually settled without arbitration. According to the terms of a supplemental agreement, NIA paid to Casecnan $117.6 million to cover past tax payments, and Casecnan paid to NIA $1.6 million (for late completion) and to the Philippines tax authority $24.4 million. The hydrology risk was essentially deferred by providing credits to NIA for water delivery below 801.9 m3/year that were redeemable against

future water delivery payments beginning in 2008. An additional dispute regarding the escalation of excess energy payments was resolved by reversing the escalation and adopting a declining tariff for excess energy delivery.

Cavite. In the late 1990s, Covanta Energy acquired a controlling interest in the 63 megawatt Cavite EPZA (also commonly referred to as the "Magellan Cogeneration" project) plant. This diesel-fired plant sold its output primarily to local export processing zones ("EPZ"), with excess energy sales to NPC. The terms of sales to the EPZ's and Napocor differed in notable ways. Most importantly, the tariff for sales to Napocor were set according to standard practice—with capacity and energy fees and some indexation to the US dollar.[289] On the other hand, sales to the EPZ's were undertaken at a discount to Napocor's prevailing grid rate.[290] As a result, reductions to Napocor's tariffs, most recently in 2002, negatively impact Covanta's revenues. This also means that other risks normally passed through to the offtaker, such as fuel price, are largely left with the project.

In 2002, the Philippine Economic Zone Authority, which is the primary offtaker for the project, served notice of termination of the PPA with Cavite. Subsequently, local courts have granted a permanent injunction staying such termination, pending resolution of the Authority's claims against Covanta, which include "non-reliable service" and "improper substitution of National Power Corporation Power for Cavite's production."[291] In 2002, Covanta wrote off its investment in Cavite.

Poland.

Poland established its IPP program in the context of a full-scale privatization of the electricity sector under a 1997 Energy Law. However, similar to the Latin American countries, Poland's reform strategy focused on the privatization of existing assets, rather than construction of new capacity. Additionally, because Poland already had sufficient generating capacity, only three greenfield IPPs have reached operations (one of which is primarily captive and thus is not part of this study). Despite the implementation of open access under the 1997 Energy Law, these IPPs—an Enron natural gas plant and a coal-fired project by PSEG—sell their energy under long term contract to the Polish grid operator and local distribution companies. Continuing efforts to reform the sector, and Poland's efforts to join the European Union, have caused problems for the IPPs. The Polish legislature has made several attempts to cancel PPAs and provide compensation in an effort to transition to more competitive markets. In addition to objections from the IPPs, these plans have faced stiff opposition from EU regulators who argue that such compensation is illegal support to national companies.

The project sample includes the two projects in Poland that qualify as private greenfield power plants. The projects vary along two important dimensions. The first factor is fuel. Poland is overwhelmingly dependent on coal for electric power generation, but has a stated goal to

[289] INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002).

[290] Covanta Energy, Form 10-K, Notes to Consolidated Financial Statements, No. 9 (2003).

[291] Covanta Energy, Form 10-K, at 23 (2005).

incorporate gas into the power sector. The projects include one coal-fired (Elcho) and one gas-fired plant (ENS). The second factor is timing. ENS reached financial close in 1997 and began operations in 1999 while Elcho did not begin operating until 2004—just weeks before the government announced its intention to cancel the long-terms PPAs.

Elektrocieplownia Nowa Sarzyna ("ENS"). ENS is a natural gas combined cycle combined heat and power plant with an installed capacity of 116 megawatts (electricity) and 70 megawatts (heat), developed by a Polish energy sector entrepreneur who partnered with Enron to finance, construct and operate the plant. ENS signed a 20-year PPA with the polish power grid company, PSE, in April 1997, and has a 20 year natural gas contract with the Polish National Oil and Gas Corp. Total project cost was $132 million, with $118.5 million of debt coming from ten European banks.

Elcho. Elcho is a $324 million coal fired, combined heat and power plant with an installed capacity of 220 megawatts (electricity) and 500 megawatts (heat), owned by PSEG (88.8%) and EC Chorzow, a Polish power generator. Elcho sells electricity pursuant to a 20-year PPA that calls for PSE to purchase 100% of Elcho's output and a similar contract with the local district heating company for the purchase of 100% of Elcho's steam output. The project achieved financial close in November of 2000, and began commercial operations in January 2004. Dresdner Kleinwort Bensen was the sole lead arranger and underwriter for the project financing ($270 million), 28% of which was denominated in Polish Zloty.

The central challenge for both ENS and Elcho has been the issue of compensation for generators whose contracts are to be cancelled as a result of EU accession. The contracts, signed between PSE and several generators, were necessary to receive financing. However, the contracts, which lock in higher prices than would be seen under a competitive market, prevent Poland from moving towards a competitive market as required under EU law. Poland's plan was to cancel the contracts and compensate the generators; such compensation is consistent with Polish law which requires compensation for takings. However, the EU Competition authority has intervened, arguing that the PPAs, while necessary to finance investments in the mid to late 1990s, conferred a "non-commerical advantage" to IPPs in violation of EU State aid law. This dispute continues unresolved.

Evaluating the success of these projects from the Polish government's perspective is difficult. Poland's dependence on coal for electricity generation has created enormous environmental problems, and the country needed to build some gas-fired capacity in order to displace coal and to demonstrate to future natural gas generators that the electricity regulator and fuel supplier were reliable partners. On the other hand, electricity sold by ENS under the PPA has reportedly been more expensive and probably unnecessary (given the oversupply that existed at the time), than the already existing coal fired capacity. The troubles that Poland is facing now, caught between EU regulators and its private investors, will not be easy to resolve.

For ENS, it appears that the experience in Poland has been mildly successful. ENS was the first foreign investor in the Polish power market and the first natural gas-fired generator in Poland, and the plant has run as a baseload plant since beginning operations. Poland has had a relatively stable macroeconomic and political environment since the late 1990s, and even though

EU accession has brought the possibility of a cancelled PPA, it appears that the Polish government intends to conduct renegotiations in a fair and transparent manner. Elcho was developed comparatively later, and has been hit hard by one of the requirement that Poland restructure its electricity market. Elcho entered into commercial operations the same week as Polish authorities announced they were canceling the PPAs, and has been mired in disputes over compensation ever since. Public reports indicate that PSEG has demanded between $370 and $420 million in compensation, and has threatened to suspend future investment in Poland.

Thailand.

Thailand began its IPP program with a highly competitive tender in 1994—out of 88 bids from 50 bidders, seven were selected for a total of roughly 5000 megawatts of private capacity. The predominantly natural gas-fired plans would sell electricity under long term baht-denominated contracts to EGAT, the national utility. At the time of the Asian financial crisis, only one project had signed its PPA and obtained financing—leaving many sponsors watching their potential baht denominated revenues shrink in relation to dollar-denominated obligations for fuel, equipment and capital. However, faced with the potential collapse of its entire IPP sector, the Thai government agreed to index the IPP payments to the dollar using a formula that accounted for expected levels of local and foreign costs in gas and coal fired plants. The bulk of Thailand's IPP capacity has, or will, enter operations between 2000 and 2006.

The primary determinants of project outcomes in Thailand are country-level factors such as the structure of the fuel markets, the method of project selection, and the 1997 macroeconomic shock. IPPs in Thailand were (originally) all partnerships between foreign and local investors, firing on natural gas as a main fuel, with similar power sales and fuel supply arrangements. Two coal-fired projects have failed in the face of public environmental opposition. A third coal-fired project (CLP's BCLP project) is only approaching commercial operations in 2006.

In light of these variations, field research in Thailand focused on illuminating the interaction and impact of factors affecting the majority natural-gas fired plants, particularly in exploring the adjustments that investors and government's made in the aftermath of the 1997 crisis. Independent Power Thailand ("Independent Power" or "IPT") is discussed in the text as capturing this experience. IPT was the first IPP to reach agreement with Thai authorities on terms for power sales and fuel supply that became the blueprint for the IPP sector. While in-depth discussions were conducted with investors, project advisors and government officials in Thailand, in-depth case studies on particular projects were not conducted.

Turkey.

Turkey was potentially an early leader in private power schemes, having authorized private investment in electricity generation in 1984. However, adverse rulings from the Constitutional Court classified electricity contracts as concessions, subject to a confusing array of overlapping authority from government agencies, and prohibited recourse to international arbitration. This chilled private investment until a 1994 law exempted BOT arrangements in electricity from the public law requirement and provided long-term power sales contracts with

the state utility (TEAS), recourse to international arbitration, and Treasury guarantees for offtake and fuel supply obligations. Six IPPs, responding to solicited bids, signed contracts under this framework before the Constitutional Court struck down the law as unconstitutional in 1996.

In 1997 the Turkish Parliament amended the Constitution and passed a BO law authorizing Treasury-backed long term contracts with TEAS, recourse to international arbitration and other incentives. This BO framework has attracted an additional 6000 megawatts of competitively bid private generation capacity, at prices reportedly 60% lower than the earlier BOT contracts.

The major recent challenges in Turkey's private power sector stem from the devaluation of the lira—between 1999 and 2002, the Turkish lira suffered a severe devaluation, ushering in a period of stress in the IPP sector, and repeated attempts to renegotiate the dollar-denominated contracts. Thus far, the controversy continues to simmer, but our research has found no major adjustments or disputes.

IPPs in Turkey vary along three variables: fuel choice (coal, hydro, or natural gas), regulatory regime (BOT or BOO) and investor composition (foreign and local). The IPP study was unable to conduct field research in Turkey, however, and instead has relied on public information that is available from abroad. Given this limitation, project selection has been designed to highlight the variation in regulatory regime, which appears to be the dominant factor driving outcomes in Turkey, and is the key factor from the Turkish experience that is relevant for the IPP study as a whole. In order to isolate as much as possible the effect of regulatory differences, the projects are similar along the other two variables: each uses natural gas a fuel, and each was sponsored by a consortium that included both foreign and local investors. Thus, two projects were selected: Enron's Trakya Elektrik from the first round of BOT projects, and Intergen's trio of projects, Gebze, Adapazari, and Izmir, from the second round of BOO projects.

Gebze, Adapazari, and Izmir. The Gebze, Adapazari, and Izmir projects (the "Projects") are three natural gas-fired, combined cycled plants built by Intergen and Enka. Gebze (1555 megawatts) and Adapazari (780 megawatts) were in operation by October 2002, and Izmir (1525 megawatts) in February 2003. Taken together, the Projects represent the largest private investment ever in the Turkish power sector, and currently provide about 14% of Turkish electricity needs. The Projects were built under the BOO framework, and have sixteen-year Power Purchase Agreements (PPAs) with TEAS, the Turkish transmission monopoly, signed in June 1998, and covered by Turkish Treasury guarantees. The projects also received a priority allocation of gas and non-interruptible supply contracts with the Turkish gas pipeline monopoly BOTAS.

The Intergen-Enka consortium that developed the Projects was among a small group of bidders chosen to bid on the first 5 BOO projects offered by the Turkish government in 1997. The consortium was the lowest bidder for all five projects, and was awarded three. The value of the Projects, which were financed as one project, was more than $2 billion at financial close. The U.S. Export-Import bank provided full political risk coverage to the participating banks, covering $860 million. OPIC also provided $300 million in capital to the project.

Available information suggests that the projects have been a success from the investor's point of view. Intergen recently completed its sale of all IPP assets in a move driven by the strategic priorities of its two shareholders—Bechtel and Shell. This sale, however, was a strategic decision, and did not reflect the performance of specific Intergen assets. From the host perspective, Turkey has enjoyed relatively robust power demand growth over the past few years, and the Projects comprise a significant part of the electricity capacity in Turkey. The BOO framework is generally viewed as less expensive than the earlier BOT projects. Nonetheless, the effect of the progressive devaluation of the Turkish lira has been significant. Industry participants suggest that the relationship between Turkish authorities and the IPPs generally has been strained. Thus far, however, no major disputes have arisen, and any adjustments to the contracts have been minor.

Trakya Elektrik. Trakya is a 478 megawatt natural gas combined cycle project located in Ereglisi, on the Sea of Marmara. Trakya was one of the first gas-fired BOT plants to achieve financial close and begin commercial operations. Financial close was reached in late 1996, when Trakya signed a 20 year PPA with TEAS, with the Turkish Treasury fully guaranteeing the payment obligations of the offtaker. The project, which cost $600 million, achieved financial close in late 1996. The project began commercial operations in June 1999.

Sponsors for Trakya include Enron (50%), Midlands (31%), Gama (10%) and Wing, Intl. (9%). (In March 2004, International Power bought Midlands' stake). Project sponsors provided $150 million in equity, along with a $95 million loan from OPIC, a commercial loan of $120 million from Bayerische Landesbank (to finance the Siemens turbines), and financing from a commercial syndicate that carried a US Exim political risk guarantee covering up to $250 million.

There have been substantial reports of disputes over the past five years of operations. In February 2003, the Turkish government announced that it intended to introduce a protocol for the cancellation of the BOT contracts (but not, apparently, the BOO contracts). It cited the high cost of the electricity generated by the BOT plants, and the fact that the Turkish Treasury was having problems shouldering the contingent liabilities created by the guarantees. In October of 2003 the government announced that it was considering seizing four natural gas BOT plants, Trakya included, on the grounds that there have been "irregularities" in their operations. In November, a study by the state Supervision Agency was concluded and it reported that that some of the costs being charged to the Turkish government were inappropriate.

Despite the relatively public disputes, conversations with a former official at Trakya indicate that the project has been an investment success. Although full details are not available, his may reflect the fact that the project operated for close to four years before attempts at renegotiation began, and to date appears to have continued operating through the stormy relationship. Given the high risk premiums and lack of competitive bidding that characterized the first round of BOT investment, a standard IPP would be able to extract substantial returns with 5-6 years of operations. From the Turkish government's perspective, Trakya and the other BOT projects have provided mixed outcomes at best. Troubles center around perceived high cost of the projects as compared to the later BOO projects. High costs reflect both the lack of competitive bidding for the BOT projects, the riskiness of IPP investment during the BOT round

when the legal basis for private power ownership was extremely uncertain, and the impact of a macroeconomic shock in 2001.

ANNEX III: PARTNERSHIPS AND RISK MITIGATION

Annex 4 presents the data underlying Figure 3 and Figure 4 in the text. These tables seek to isolate the impact of local partners and of prominent international partners in enhancing the risk mitigation capacity of independent power projects.

In order to control for country variables that affect risks and project outcomes, Annex 4 rates each project according to whether that project confronted a particular risk and whether that risk affected project outcomes. Results indicate the success rates only for projects that actually confronted a risk. A project is rated as having confronted a risk ("1") if similarly situated projects in the same country were negatively affected by that risk. Thus, if no project in a country faced fuel supply problems or non-payment, that project is rated as having not confronted that risk ("0"). While imperfect, this method controls for the effect of country wide factors, and highlights how projects perform in comparison to similarly situated projects.

A project is rated as a "success" for a particular risk ("1") if that risk did not affect project outcomes. Successful mitigation of a risk will not always appear as a dramatic story. Often risks are mitigated with effective planning or with quiet dispute resolution. Thus, where projects faced a risk (as defined in the previous paragraph), and that risk did not constrain or affect project outcomes, that project is considered to have successfully mitigated that particular risk.

The symbol "-" indicates that insufficient information is available to make a reasonable estimate of a given risk or its affect on a project.

"Fuel": This variable indicates whether the project confronted risk in the supply or price of fuel.

"Dispatch": This variable indicates whether the project confronted the risk of low dispatch or utilization.

"Non-Pay": This variable indicates whether the project confronted the risk of a prolonged period of non-payment by the offtaker.

"Renego": This variable indicates whether the project confronted the risk of unilateral renegotiation of fundamental contract terms. Projects that were renegotiated by mutual agreement in ways that appear to have limited (or otherwise acceptable) impact on returns are still rated a success in this column.

Table 1: Local Partners and Risk Mitigation

Project Name	Local Sponsors	Fuel	Success	Dispatch	Success	Non Pay	Success	Renego	Success
Project 1	Foreign	1	1	1	1	1	1	1	1
Project 2	Foreign	1	0	1	0	1	1	1	1
Project 3	Foreign	0	-	0	1	0	1	0	1
Project 4	Foreign	1	0	1	0	1	0	1	0
Project 5	Foreign	0	1	0	-	0	1	0	1
Project 6	Foreign	0	1	0	-	0	1	0	1
Project 7	Foreign	0	1	0	-	0	1	0	1
Project 8	Foreign	1	1	1	0	1	1	1	0
Project 9	Foreign	0	1	0	1	0	1	0	1
Project 10	Foreign	0	1	0	1	0	1	0	1
Project 11	Foreign	0	1	1	1	0	1	1	1
Project 12	Foreign	1	0	1	0	0	1	1	1
Project 13	Foreign	0	0	1	1	1	0	1	0
Project 14	Foreign/Local	1	0	1	0	1	0	1	1
Project 15	Foreign/Local	1	-	0	-	1	1	1	0
Project 16	Foreign/Local	-	-	-	-	1	1	1	1
Project 17	Local	1	1	1	1	1	1	1	1
Project 18	Foreign/Local	-	-	-	-	1	1	1	1
Project 19	Foreign/Local	0	1	0	1	0	1	1	1
Project 20	Foreign/Local	0	1	0	1	0	1	0	1
Project 21	Foreign/Local	1	1	1	0	1	1	1	1
Project 22	Foreign/Local	1	0	1	1	1	0	1	1
Project 23	Foreign/Local	0	1	0	-	1	1	1	1
Project 24	Foreign/Local	1	-	0	-	1	1	1	0
Project 25	Foreign/Local	0	1	0	-	1	1	1	1
Project 26	Foreign/Local	0	-	1	0	0	0	1	0
Project 27	Foreign/Local	1	1	1	1	1	0	1	1
Project 28	Foreign/Local	1	1	1	1	1	0	1	1
Project 29	Foreign/Local	1	0	1	0	1	0	1	0
Project 30	Foreign/Local	1	0	1	0	1	1	1	0
Project 31	Foreign/Local	1	1	1	1	1	0	1	0
Project 32	Foreign/Local	0	1	0	1	0	1	1	1
	Total	16	7	17	8	20	12	25	16
	Local	11	5	10	5	15	9	18	12
	Foreign	5	2	7	3	5	3	7	4
	% Success Local	**0.45**		**0.50**		**0.60**		**0.67**	
	% Success Foreign	**0.40**		**0.43**		**0.60**		**0.57**	

Table 2: Multilateral and Bilateral Lenders and Risk Mitigation

Project Name	Multi/Bilateral?	Fuel	Success	Dispatch	Success	Non Pay	Success	Renego	Success
Project 1	No	1	1	1	1	1	1	1	1
Project 2	No	1	0	1	0	1	1	1	1
Project 3	No	0	-	0	1	0	1	0	1
Project 4	No	1	1	1	0	1	1	1	1
Project 5	No	1	0	1	0	1	1	1	0
Project 6	No	0	1	0	-	0	1	0	1
Project 7	No	1	0	1	0	1	0	1	0
Project 8	No	1	1	1	1	1	0	1	0
Project 9	No	0	1	0	-	1	1	1	1
Project 10	No	0	1	1	1	0	1	1	1
Project 11	No	0	-	1	0	0	0	1	0
Project 12	No	0	0	1	1	1	0	1	0
Project 13	No	1	-	0	-	1	1	1	0
Project 14	No	1	-	0	-	1	1	1	0
Project 15	No	0	1	0	1	0	1	1	1
Project 16	No	0	1	0	1	0	1	1	1
Project 17	Yes	1	0	1	0	1	0	1	1
Project 18	Yes	1	0	1	0	1	0	1	0
Project 19	Yes	0	1	0	-	0	1	0	1
Project 20	Yes	0	1	0	-	0	1	0	1
Project 21	Yes	1	0	1	1	1	0	1	1
Project 22	Yes	1	1	1	1	1	1	1	1
Project 23	Yes	1	1	1	1	1	1	1	1
Project 24	Yes	1	1	1	0	1	1	1	0
Project 25	Yes	0	1	0	-	1	1	1	1
Project 26	Yes	0	1	0	1	0	1	0	1
Project 27	Yes	0	1	0	1	0	1	0	1
Project 28	Yes	0	1	0	1	0	1	0	1
Project 29	Yes	1	0	1	0	0	1	1	1
Project 30	Yes	1	1	1	1	1	0	1	1
Project 31	Yes	-	-	-	-	1	1	1	1
Project 32	Yes	-	-	-	-	1	1	1	1
	Total	16	7	17	8	20	24	25	23
	No Prominent	8	3	9	4	10	4	14	7
	Prominent	8	4	8	4	10	5	11	9
	% Success No P	**0.38**	0.43	**0.44**	0.50	**0.40**	0.17	**0.50**	0.30
	% Success P	**0.50**	0.57	**0.50**	0.50	**0.50**	0.21	**0.82**	0.39