Foreign Direct Investment in New Electricity Generating Capacity in Developing Asia: Stakeholders, Risks, and the Search for a New Paradigm

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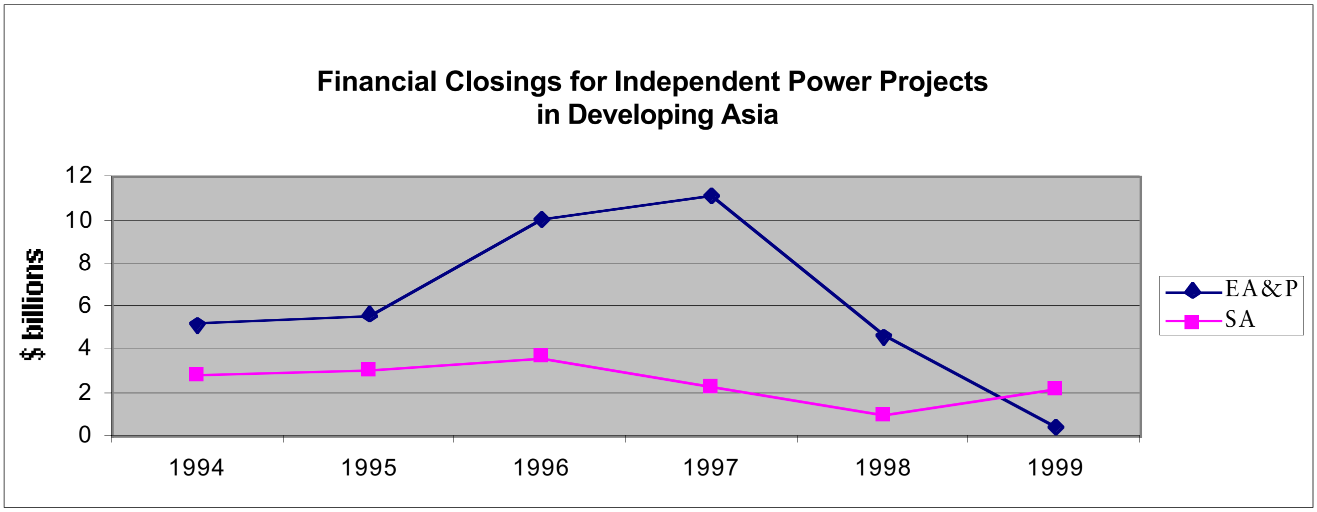
I. Background

The rate of investment sufficient to provide developing Asia with a reasonably adequate supply of electricity is immense, ranging from a World Bank estimate of 2000 megawatts (MW) each month (which translates into an annual investment of about $35 billion per year) to even higher estimates.[1] All of the larger countries of developing Asia have been looking for foreign direct investment (FDI) to provide a significant amount of the needed capital. In 1996, financial closings for new power projects in developing Asia reached $13.7 billion, or almost 40 percent of the lower range of the estimated requirement.[2] Although data on the foreign share of the monetary value of financial closings is not available, it is likely to be over 80 percent.[3] Thus, the foreign share of total direct investment in power projects in developing Asia appeared to have been around 30 percent before the East Asian currency crisis.[4]

Not only was the level of FDI high, it was also growing rapidly, as shown in Figure 1. Prior to the onset of the East Asian currency crisis in mid-1997, FDI in electricity-generating capacity in the developing countries of Asia appeared to be a robust market destined for continuous growth. The economic effects of the crisis are well-known—serious contractions of output in 1998 in Thailand, Indonesia, Malaysia, and South Korea, and a significant deceleration of growth in the Philippines. Of the major developing economies in Asia, only China and India avoided significant deceleration of growth or outright contraction.

Accompanying the financial turmoil and contraction, Figure 1 shows that the dollar value of financial closings for independent power projects (IPPs) fell to under $0.5 billion in 1999, from over $11 billion in 1997 for East Asia and the Pacific. In South Asia, the fall was less precipitous, but 1999 activity was still significantly less than that of 1996.



Source: World Bank Private Participation in Infrastructure (PPI) database

Moreover, IPPs that had come into service (particularly in Indonesia and Pakistan) have been faced with government demands to renegotiate their power purchase agreements (PPAs).[5] The principal causes for these calls for renegotiation are a downward-shifting demand schedule (due to economic crisis) and rapidly rising tariffs (largely indexed to the foreign exchange rates of the countries of the principal investors). Moreover, in Indonesia and Pakistan, new governments contend that their predecessors agreed to pay too much for electricity as a result of corruption.

Particularly in Indonesia, where the decline in GDP was probably on the order of 15 percent in 1998 and perhaps another 5 percent in 1999, macroeconomic conditions alone might explain the collapse of the IPP market. However, it may also be that macroeconomic collapse merely hastened the demise (or at least the overhaul) of a way of structuring IPP markets that was already severely flawed. For example, the World Bank convened a conference at Cartagena, Colombia in May 1997 (before the East Asian currency crisis) that focused on the public risk being undertaken in private infrastructure. The contributors identified a number of problems concerning the way private infrastructure projects are developed. These problems, in their opinion, require significant, if not radical, change for IPPs to be viable from a public perspective. Areas they found in need of change included the government's role as guarantor, the financial structure of PPAs, and the degree of competition. (Irwin et al, 1997) Their general conclusion was that the current paradigm was at best suboptimal, and at worst, unsustainable. There was also a consistent suggestion running through the contributions that a new paradigm could not emerge without the host countries undertaking fundamental, broad-scale economic and institutional reform.

With the crisis countries now recovering, and with the noncrisis countries continuing to grow, there is now a question whether the pace of reform can keep up with the growth of power consumption and implied capacity expansion that is necessary to support continued economic growth. To date, there is little reason for optimism on this score: institutional reform inevitably creates economic, political, and social disruption for significant portions of society and faces significant resistance. Moreover, to be done well, reform must be done carefully; this, too, takes time. What, then, is to be done? To what degree are conventional ways of developing IPPs fatally flawed, and to what extent can they be repaired and still remain viable? What are the alternatives, and what are their own strengths and flaws?

This discussion paper provides an introduction to the rationale and commercial structure of IPPs under the conventional contract-dominated structure (the "Old Paradigm") and under emerging spot-market structures (the "New Paradigm"). It also delineates the market structures implied by these paradigms and identifies the stakeholders and their interests. However, the primary purpose of this paper is to *raise* questions rather than *answer* them, and to stimulate discussion of whether the questions raised are the right ones.

II. The Rationale for Private Power

Until relatively recently, most of the world has regarded the production and delivery of electric power as an activity most appropriately provided by government, due to its natural monopoly characteristics and to convictions that its social value exceeded its private value. The United States and Japan were the major exceptions, in that most of their electricity has been provided by integrated private electric utilities operating as franchised monopolies under strict government regulation. Even in the United States, however, government ownership is still significant, involving major generating entities (e.g., Bonneville Power Administration, the Tennessee Valley Authority), integrated municipal utilities (e.g., Seattle Power and Light, the Los Angeles Department of Water and Power), and distribution entities (e.g., rural electric cooperatives and municipal utilities).

Evolution of IPPs in the United States

Beginning in the 1980s, it was increasingly recognized that electricity generation could be decoupled from transmission and distribution. Action was triggered by three major developments: one social and political, another technical, and the third economic. The social and political motivation in the United States was concern about global shortages of fossil fuel and air pollution. This led to the Public Utility Regulatory Policy Act of 1978 (PURPA), which permitted "Qualifying Facilities" (QFs) to be exempt from the provisions of the Public Utility Holding Company Act of 1935 (PUHCA), and which mandated that utilities buy the power they generated at "avoided cost." QFs are IPPs that use energy-efficient technologies (such as cogeneration) or renewables. Thus, IPPs were born as a consequence of environmental concern.

Each QF was typically set up as a single-purpose company that signed a PPA with a particular utility at the utility's avoided cost—loosely interpreted as what the utility would have to pay to add conventional generation and operate it. Each PPA had a long term—typically over ten years—and was on a "take-or-pay" basis. The purchasing utility was obligated to pay for a specified amount of power during the contract period, whether or not it wanted or needed it. The structure of the PPA made it possible for the QF to be financed on a limited-recourse basis. That is, in the event of default of the QF company, lenders had recourse to assets and revenues from the PPA, rather than to the balance sheet of the QF owner.

Technology and economics (in the form of natural gas prices) entered the picture as companies that sponsored IPPs realized that they could generate electricity at competitive prices—even in the absence of the incentives for QFs—with modern combustion turbines burning natural gas. Improved combustion turbines began to rival the thermal efficiency of steam-powered plants, and deregulation of natural gas and the consequent reduction in prices made gas-fired combustion turbine generation competitive in price with coal-fired steam generation. Moreover, the ability to capture waste heat from the combustion turbines and use it to raise heat for a steam turbine in combined cycle generation further enhanced the competitiveness of combustion turbine technology. Since efficient combustion turbines can be built with much smaller capacity than efficient steam plants, they shattered the notion that substantial economies of scale were a characteristic of electricity generation. This implied that ownership and development of a conventional generation facility no longer needed to be the exclusive province of large integrated public utilities.

The recognition that efficiently generated, nonrenewable electricity could be produced by entities other than utilities led to the Energy Policy Act of 1992. This act provided for a class of "exempt wholesale generators" (EWGs) that can generate and sell electricity to utilities or large industrial customers without being regulated as utilities under PUHCA. It also mandated that EWGs would have access to utility transmission lines at reasonable charges so they could sell to purchasers of their choice. The result was experience in developing and building IPP projects that could be transferred to overseas markets. Thus, in the early running, the dominant international firms have tended to be American (e.g., AES Corporation, InterGen, Entergy, and Enron), but major players are rapidly emerging from Germany, the United Kingdom, Japan, Taiwan, France, Chile, and other countries.

The next important step came during the 1980s with privatization of generation, first in Chile and then in the United Kingdom and other countries.[6] In developing Asia, however, over 95 percent of the FDI that has gone into infrastructure during the period 1990–98 has gone to development of new ("greenfield") projects. (Sader 1999, p. 166) This paper will focus on greenfield IPPs, and little more will be said about privatization of existing assets. Nevertheless, it should be noted that occasionally the distinction is not as clear as it may seem. For example, state-owned utility systems may sell minority interests in generating plants to private investors as a means of financing expansion of state-owned generating capacity.

Motivation for IPPs in Asia

The primary motivation for official support of FDI in IPPs in developing Asia has been that the growth of electricity consumption has outstripped the financial ability of state-owned utilities to build adequate capacity.[7] Inasmuch as most Asian governments have been reluctant to incur public debt—especially foreign debt—for the purpose of expanding electricity and other infrastructure, FDI is attractive because it is a means of financing capacity expansion without borrowing.[8] Also, as in the United States, competition among private entities to supply power is expected to bring state-of-the-art technology and operating practices that lower the price of electricity and increase reliability relative to what would be the case if the state-owned utility provided the same increase in capacity.

These motives contrast with those of privatization of electricity-generating assets, in which the revenue from the asset sales is often a major motivation. In Latin America, prior sovereign borrowing had placed governments in a precarious fiscal position. Using the proceeds to retire official debt was an important consideration in privatization, as was improving efficiency by introducing private-sector incentives into the electricity sector.

III. The Conventional PPA-Based Independent Power Project—the Old Paradigm

Developing an IPP is an extremely complex undertaking, even under the simplest of circumstances in the developer's own country. FDI offers another layer of complexity. If the host country is underdeveloped in its institutions and also subject to high levels of political and macroeconomic risk (as is the case of developing countries in Asia and elsewhere), there is yet another layer of complexity and risk.

Inasmuch as IPP agreements are complex and varied, characterizing a paradigm does violence to the diversity that constitutes reality. Nonetheless, particularly in developing countries, an archetypal "Old Paradigm" IPP structure includes the following:

- A stand-alone development corporation, owned principally by large corporations from prosperous countries;
- At least 60 percent financed by debt;
- Limited-recourse debt financing, secured by a long-term, take-or-pay PPA;
- A PPA with foreign exchange rate and/or inflation protection, with a publicly owned distribution entity;
- A central government guarantee that the distribution entity will live up to its obligations under the PPA and other guarantees (covering convertibility, transfer, foreign exchange rate, and other risks) that create unfunded contingent liabilities for the central government;[9]
- Political risk insurance provided by private insurers, investors' national governments, or the Multilateral Investment Guarantee Agency (MIGA).

Market Structure of the Old Paradigm

The Old Paradigm market structure is that of many IPPs selling to a single buyer under long-term PPAs. In the United States, the buyer is usually a transmission and distribution utility that may or may not own generating capacity. In developing Asia, the buyer is always (to date) an integrated, state-owned transmission and distribution company.

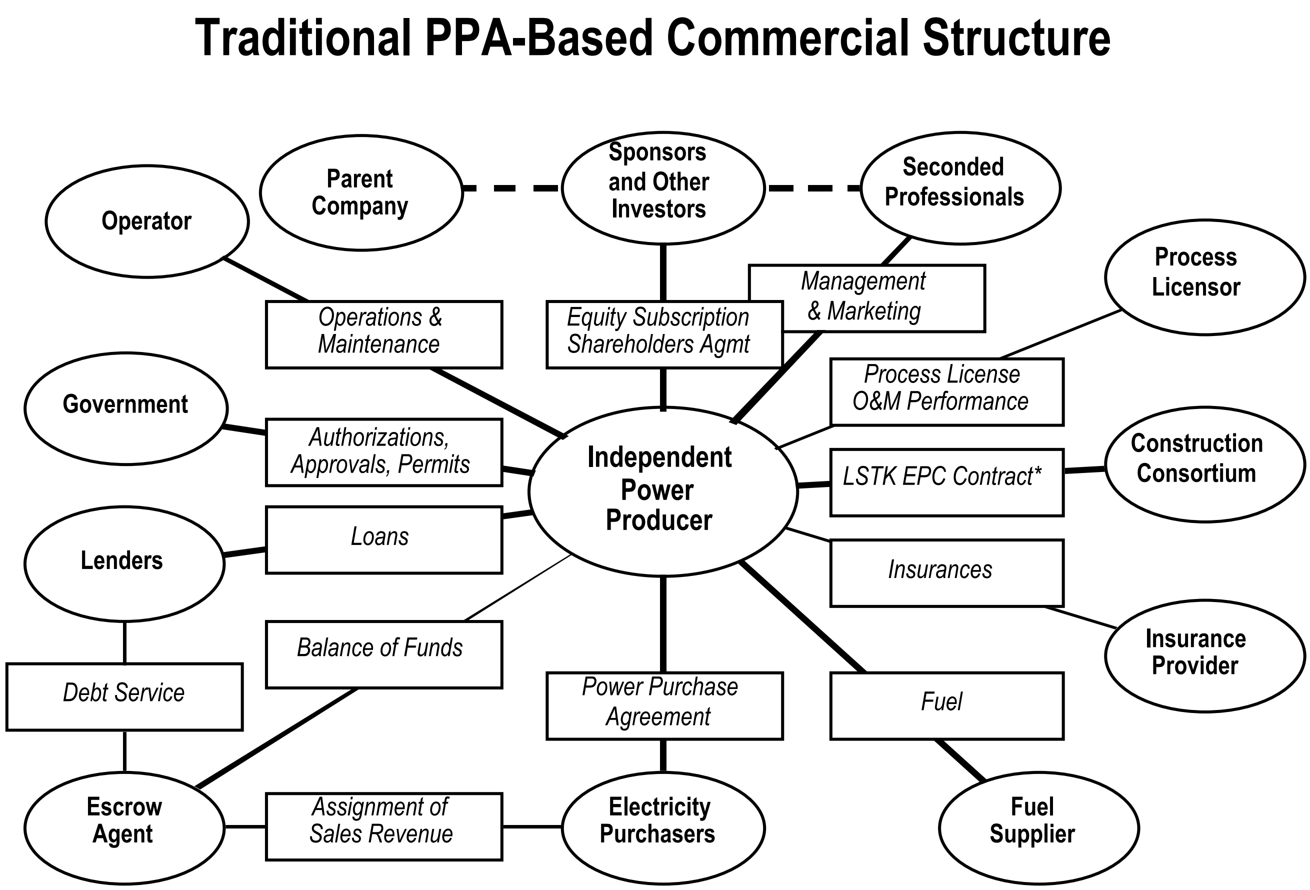
The fact that there is a single buyer implies the inevitability of long-term PPAs to offset its monopsonistic power. Only by contractual obligations before undertaking construction can IPPs avoid the buyer driving compensation for power toward short-run marginal costs, with no compensation for capital expenditures, much less a return on equity.

Direct Stakeholders

Figure 2 shows the general commercial structure of a private power project and identifies the major stakeholders in an IPP and the roles they play.

The key classes of direct stakeholders are project sponsors, government, electricity purchasers, lenders, providers of equipment and construction services, insurers, fuel suppliers, and operators. These are listed in a very loose order of the sequence in which they enter the development process. All are essential. It is hard to imagine how a project could be developed unless each is part of an agreed framework.

Figure 2



*LSTK EPC Contract = Lump-sum turnkey engineering-procurement-construction

Sponsors/Equity Holders

The sponsors are the equity holders. They often initiate the project, both in terms of identifying the need for power, and making a specific proposal to fill the need with new generating capacity in a particular way at a particular site. At other times, they respond to a request from a purchaser for bids to supply power. These requests are at various levels of specificity concerning the amount of power to be supplied, the conditions of supply, the broad technology or fuel (e.g., coal-fired thermal), and other considerations.

The sponsors, who typically form a special purpose project company (which is the IPP), may consist of several companies that have other stakes in the project. They may all be from the same country, from different countries, and may or may not include local partners. In some cases, the sponsors are public–private partnerships. For example, Enron, Bechtel Enterprises, and General Electric—through offshore subsidiaries—formed Dabhol Power Company to build the first phase of a major power plant in Maharastra state in India. Later, part of the equity was sold to the Maharastra State Electricity Board. Enron is also a stakeholder as fuel supplier and as the operator of the plant. Bechtel's construction arm has engineering, procurement, and construction stakes; General Electric is a major equipment supplier; and the Maharastra State Electricity Board is the electricity purchaser. There are also other major sponsors of IPPs, such as AES Corporation, whose sole business is developing, owning, and operating electric power facilities. Moreover, the Asian Development Bank and the International Finance Corporation, a part of the World Bank group, may take equity positions. Typically, equity accounts for 25–40 percent of the project's total cost. The rest is raised through borrowing.

It is possible to raise equity through private placement with wealthy individuals or institutional investors. In the United States, for example, the Securities and Exchange Commission's (SEC) Rule 144A allows qualified institutional investors to buy securities not registered with the SEC, and allows these securities to be traded publicly after a period of three years. (Razavi 1996, pp. 98, 100)

It is the sponsors' responsibility to determine whether a given project is economically, politically, and technically feasible, and whether it is likely to obtain adequate financing support. One or more of the sponsors may take the lead in this regard and bring in other partners later in the process. In forming the project company, it is important that the partners be compatible in their objectives, in what they bring to the project in terms of expertise and financial strength, and in their ethics. The project companies make long-term investment commitments that may or may not call for them to transfer their equity stakes to some host-government entity at the end of a specified period.[10] In order to make sure that the projects are marketed and operated well, the sponsors may assign employees to the IPP.

Governments

Governments play important roles throughout the process of developing an IPP and monitoring its compliance with laws and regulations throughout its operating life. Since electric power is an important sector of the economy, governments also have a stake in issues of adequate power supply, efficiency, fairness, and foreign control.

Both national and subnational governments play key roles in granting initial permits and licenses. These may include permission to build a power plant, to build it on a particular site, environmental permits, and other permits and licenses as called for by law and regulation. Perhaps more vital than the approvals specific to a particular plant is the general legal, institutional, and enforcement framework that affects all IPPs that have substantial foreign ownership.

An illustration of the critical role of such a framework is the Dabhol project, which was negotiated by the Dabhol Power Corporation (DPC) and the Maharastra State Electricity Board under the aegis of the state government. However, the negotiations were concluded during a political campaign, and the opposition made the project an important campaign issue, alleging that the process was corrupt, the price of power was too high, that environmental and local villagers' concerns were not adequately considered, and other charges.

When the opposition won the election, the new government ordered the project to be shut down without compensation to DPC. By this time, though, DPC claimed that it had spent around $200 million, for which it was entitled to be compensated, according to the terms of its contract. Moreover, the contract stated that disputes would be subject to international arbitration. The Indian Supreme Court upheld the DPC's right to take the dispute to arbitration. The prospects of arbitration encouraged the parties to negotiate a settlement that allowed the project to proceed and lowered the price of electricity, and they agreed on other terms as well. The process was difficult for all parties, but an important lesson was that investors' rights were protected by contract, despite an adverse turn in the political climate—an immensely significant consideration when investors and their lenders are making twenty-year commitments.

In cases where national government believes strongly in attracting IPPs and the IPP and/or its lenders do not perceive the electricity purchaser to be financially sound or reliable, the national government may provide sovereign guarantees against default on the terms of the PPA.

What is somewhat surprising at first glance is that regulators, to the extent that they are separate from the rest of government and from the electricity purchaser, have little role in structuring an IPP under the traditional PPA paradigm. Regulation typically operates at the retail level (households, farms, commercial establishments, institutions, and small industries), while the PPA is between the IPP and a wholesale purchaser (a utility or a large industrial establishment).

Electricity Purchasers

In developing Asia, publicly owned utilities are the predominant purchasers of electricity from IPPs. In principle, large industrial customers with access to high voltage lines could be purchasers as well. The contractual relationship that binds the purchaser and the project company is the PPA. The price of power under the PPA is typically indexed for fuel and other local cost escalations, including wages. A key characteristic of the PPA is that the purchaser absorbs all market risk. That is, the purchaser is responsible for understanding the aggregate demand function of end users, for whom it acts as an intermediary with the IPP. If the demand for electricity does not meet expectations, the purchaser is still obligated to pay for the contracted amount under the PPA's take-or-pay provisions.

An additional characteristic of PPAs where foreign investment is involved is that the plant's foreign cost components—especially those related to power-generating equipment and other equipment that is unavailable locally—are typically indexed to the exchange rate. The primary purpose of exchange rate indexation is to protect the project company from the risk of a movement in exchange rates that would depreciate the foreign currency value of local revenues, when many of the costs had been incurred in foreign currency.[11] Of course, in 1997–98, when currencies in East Asia depreciated rapidly, this created rapidly rising costs to the purchasers that they could not easily pass on to end users. These local currency price increases were largely responsible for default on the part of purchasers and for demands to renegotiate PPAs, as in the Paiton 1 project in Indonesia (a 1,230 MW plant built as a joint venture of Mission Energy and General Electric).[12]

Under conditions of growing prosperity and economic strength for host countries, foreign exchange indexation could also work the other way. If the local currency appreciates against the foreign currency, then the foreign currency component of costs declines in local currency terms. Thus, in the larger economic context, foreign exchange indexation is procyclical: it tends to deliver lower local currency prices of electricity when the economy is strong and its currency appreciates, and higher prices when the economy is weak and the currency depreciates.

Unlike the majority of their counterparts in developed countries, many power purchasers have weak, or at best, untried finances. This is particularly true of government-owned utilities, whose revenue collection mechanisms are poor and whose costs are high for reasons that include inappropriate retail rates, power theft, and overstaffing. A weak financial position means an increased risk of default on their PPAs if the purchasers are not generating adequate revenue. Even without such problems, a utility may not have established a long enough track record as an independent agent to be regarded as completely creditworthy. Thus, developers and lenders often insist that a third party, usually the central government, provide guarantees against default.

Lenders

Lenders as a class provide about 60–70 percent of a power project's cost, with the balance provided by equity. International commercial banks typically provide most of the loans, which are frequently syndicated among a number of banks. The loans are made to the project company and are typically secured only by the project company's physical assets and the stream of revenues from the PPA—with no recourse to the sponsors. Thus, such lending is known as "project finance" or "limited-recourse financing."

In addition to commercial banks, multilateral development agencies such as the Asian Development Bank, the International Finance Corporation, or the World Bank may provide loans. The International Finance Corporation and other lender/investors may also make "semi-equity" loans in the form of convertible debentures or subordinated loans. Lending to support foreign investors and the equipment exports that their investments imply may also come from the investor countries' official export financing agencies. These are usually in the form of export credits to exporters or loans to purchasers of their country's equipment and services under a variety of arrangements. These loans are often made on concessional terms. All countries belonging to the Organisation for Economic Cooperation and Development (OECD) and some developing countries have such arrangements.[13]

Debt financing in the form of bonds is also a source of financing. Insurance companies and pension funds may be participants. Private placement of debt is another option. In the U.S. the SEC's Rule 144A provides improved liquidity and efficiency of the private placement market by giving more freedom to institutional investors to trade restricted securities.

An important element of all types of lending is that lenders assume only downside risk and have no control over the execution and management of the project. The most they can get in return is full payment of interest and principal. However, lenders incur substantial losses if project costs are too high, and/or revenues too low for repayment of principal and interest, inasmuch as their only recourse is to the project itself. Thus, lenders take care to assure themselves that the project team is reliable and that the purchasers will be able to live up to the terms of the PPA. Where they have doubts, they will insist on various types of insurance (to be discussed below) and third party guarantees against purchasers' default from the central government.

Lenders may also insist on additional financial security arrangements. For example, they may require all revenues due to the project to be paid by the purchasers to an escrow agent, as shown in Figure 1. The escrow agent then ensures that the debt is serviced properly and that the project company can meet operating expenses before returning the balance of the funds to the IPP and therefore, to the sponsors.

Providers of Equipment and Construction Services (Contractors)

Constructing and equipping an IPP is undertaken on a "lump-sum, turn-key" (LSTK) basis. This means that the engineer–constructor and equipment supplier deliver a plant at a fixed cost (lump-sum) and on a committed schedule that guarantees that the plant will work from the day it is turned over to the sponsors (turn-key). Regardless of how much the plant costs, the contractors are reimbursed a fixed amount. If the project costs less than anticipated, they pocket the difference. If it costs more, they absorb the difference. Also, if the schedule is not met and if the plant does not immediately perform according to specifications, the engineer–constructor is subject to liquidated damage claims by the sponsor.

The motivation for this type of contract is that sponsors and lenders require cost certainty to match the fixed revenues specified in the PPA. Thus, under LSTK contracting, risk shifts to the contractors. In principle at least, the risk is priced so that the expected profit under LSTK contracting is greater than under cost-reimbursable contracting, which is more flexible and likely to be cheaper but shifts risk to the sponsor.

One implication of LSTK contracting is that contractors use proven technology that minimizes risk of cost, schedule overruns, and performance problems. Equipment vendors, who provide necessary licenses and warranties, provide this technology. Some major engineer–constructors offer standardized families of plants for given capacities and given fuels. The effect this type of contracting has on technological innovation is an open question. Standardization would seem to be an inhibiting factor. However, it also implies that whatever an engineer–constructor builds in its home country is likely to be built overseas as well.

Fuel Suppliers

As in the case of construction and equipment, fuel supply must have cost and delivery certainty. Thus, fuel is typically supplied under long-term "supply-or-pay" contracts, in which the supplier is subject to penalties for failure to deliver agreed volumes on a timely basis. The pricing terms of the contracts vary from project to project. Some have a fixed price for the entire period of the contract. Others may call for an initial benchmark price and then be indexed for changes in market prices. If the price is fixed, the supplier absorbs the risk of delivering at below-market prices and presumably negotiates a price that compensates for this risk. If the price is indexed, the risk shifts to the IPP, who in turn is likely to pass it on to purchasers in the form of indexation clauses in the PPA.

Operators

Operators of the power plant, if they are not part of the IPP, undertake to operate and maintain the plant under a long-term contract. Typically, these are cost-reimbursable contracts with performance incentives and penalties linked to the power plant's reliability.

Insurers

Any type of construction project is subject to a substantial amount of risk, much of which is insurable. Private insurance companies are likely to provide the IPP with insurance for some of the risks incurred in construction (including natural disasters), for losses or damage to equipment in transit, for interruptions in the construction schedule due to strikes or civil unrest, and for general liability.

Further, some risks are insured by agencies of exporting countries and by the World Bank's Multilateral Investment Guarantee Agency (MIGA). MIGA offers insurance against host government action that impedes convertibility of proceeds from local currency to foreign currency, expropriation, war and civil disturbance, and breach or repudiation of contracts with host governments or their agencies.[14]

Indirect Stakeholders

In addition to the direct stakeholders in the IPP, there are indirect stakeholders that have no standing in the contractual agreements that define the IPP, but hold important stakes in the outcome. Most important are the end users of electricity, for whom the IPP is presumably developed in the first place. In addition, IPPs, like all power plants, have important environmental and consumption externalities. These externalities comprise a public stake that is separate from that of end users.

End Users

End users are related to the IPP only through the power purchasers, which are typically utility companies that control transmission and distribution networks and power marketing functions. The relationship between end users and the IPP is intermediated by electricity pricing policies and the efficiency of the transmission and distribution system. However, there is no particular reason for the end user's relationship to the IPP to be any different than it is to generation in an integrated utility system.

Environmental and Consumption Externalities

It is not clear what impacts foreign-owned IPPs will have on air quality. On the one hand, the need for cost certainty implied by LSTK contracting imparts a conservative bias to technology choice that leads in turn to proven design and standardization. Thus, in spite of the apparent attractiveness of new, environmentally benign technologies—such as integrated coal gasification and combined cycle generation (IGCC) in such coal-intensive countries as China and India—it is unlikely that the risks associated with their costs and performance would make them good candidates for IPPs.

On the other hand, standardization implies that foreign sponsors of IPPs are likely to use the same technologies that they use in their home markets, inasmuch as custom-building less sophisticated technologies that also pollute more would probably have less cost and performance certainty than standardized designs. Moreover, the incentives for cost minimization in IPPs suggest that they will be operated efficiently. Thus, they are likely to have lower heat rates (BTU per kilowatt hour) than generation facilities that have no such incentives for cost reduction. Lower heat rates imply less fuel consumption and therefore less pollution.

There appears to be little information on how foreign-owned IPPs actually affect air quality compared to the alternative of domestic investment, either by the utilities or by domestically owned IPPs. Given that foreign-owned IPPs are likely to play an increasingly important role in the expansion of generating capacity in developing Asia, it would be desirable to develop deeper insights into how they affect the environment.

Of course, electrification in general has a number of impacts on the environment. Some are positive (such as the reduction of deforestation), and some are negative (such as air pollution, land use, and waste disposal). However, IPPs do not seem to be different from any other mode of ownership of electricity generation in these regards. The same is true of consumption externalities that particularly result from the initial extension of electrical service, including improved public health, reduced burdens on women for household chores, and reduced infant mortality. For example, in the United States, some of the effects of rural electrification, beginning in the 1930s, were improved public health (through increasing adequate supplies of clean water, and better food storage and diet); reduced burdens on women for household chores; reduced infant mortality; and diminished pressures on urban areas of rural–urban migration (due to improving rural standards of living). (Clayton Brown 1980, pp. xiii-xvi)[15]

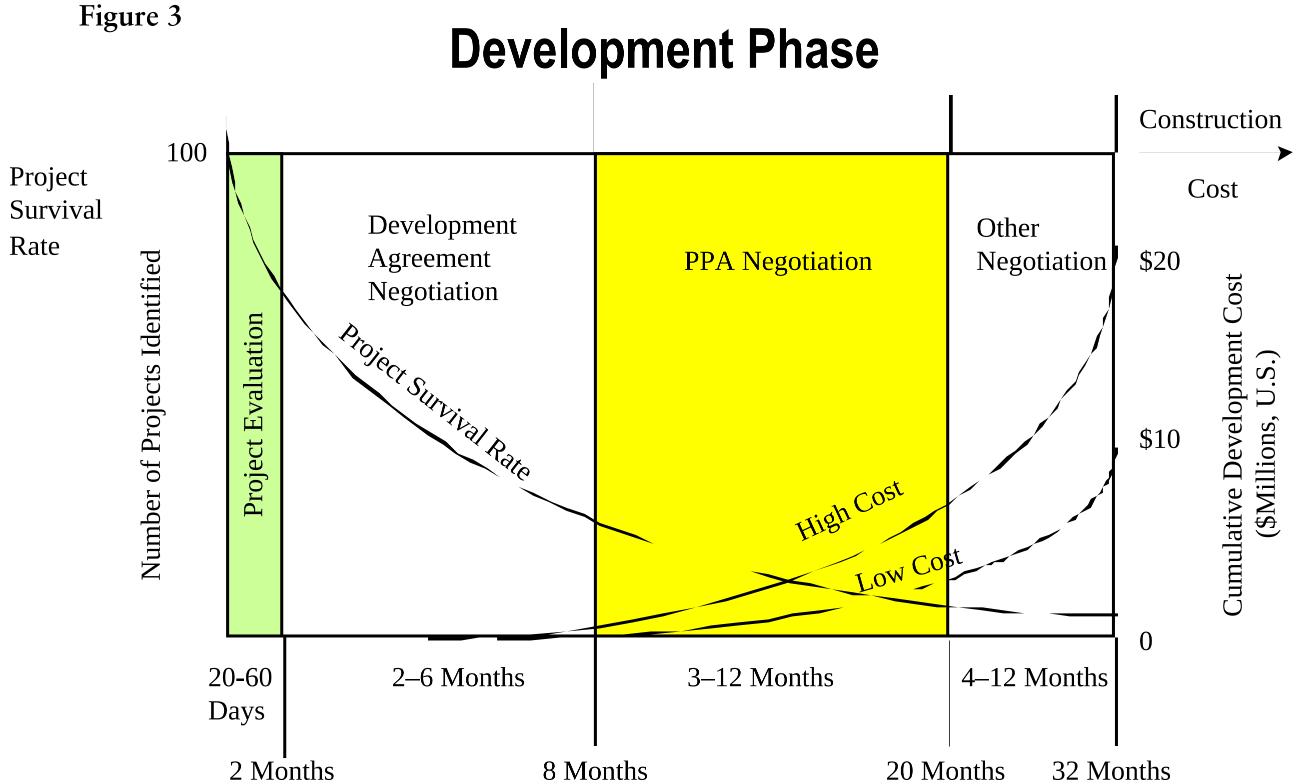
The Life Cycle of a Conventional PPA-Based IPP

There are three phases in the life cycle of an IPP. The first, and most distinctive, is the development phase. The second is the construction phase, which differs from that of a conventional utility only in the terms and conditions of the development phase. The third is the operations phase, in which there are some considerations that are distinctly different from a conventional utility.

Development Sequence, Time, and Cost

The process of bringing the stakeholders together—the development phase—is complex and time-consuming. The first task is to identify viable projects. Once it is determined that a project is worth pursuing, each of the stakeholders must sign an agreement with the IPP that delineates each party's rights and obligations. Bechtel Enterprises (a major developer of private infrastructure projects, including IPPs) identifies four distinct stages in the development phase of private infrastructure projects, as presented in Figure 3. (The implied numbers in Figure 3 are representative but do not necessarily show specific Bechtel Enterprise experience with IPPs.)

Figure 3



The key points to be derived from Figure 3 are:

- Out of every one hundred possible projects, very few—say, five to ten—make it to financial close and construction.
- It costs millions of dollars—say, \$10–\$20 million—to bring these few projects to the point at which construction begins.
- The time between the identification of a potential project and the beginning of construction is commonly about three years. It typically takes another three years or so to construct a power plant. Therefore, the time from the identification of a potential IPP to the time it generates power is likely to be about six years.

During the project evaluation stage, individual projects are identified and a preliminary assessment is made about the chances of going forward. Basic concerns include: whether expected revenues will meet expected costs; the competitive position of the sponsors; whether there is host government support; whether the political and institutional context is acceptable even if there is support; whether financing is feasible; and whether environmental conditions are acceptable.

If the project is attractive, negotiations leading to agreements with potential co-sponsors are undertaken, and more refined feasibility analysis is conducted. In this "development agreement negotiation" stage, a number of projects fall by the wayside. New information may make them less attractive than appeared to be the case originally, or agreements with potential co-sponsors who are complementary and compatible may not be possible. By this time, some eight months after original identification, the original one hundred projects may well have dwindled to about twenty-five.

Once the project development agreement is signed, attention then turns to submitting a bid or entering into direct negotiations with the purchaser over the PPA. If a bid is submitted and accepted, intense, time-consuming negotiations over detailed terms and conditions are still necessary before a PPA is signed. The PPA, of course, is the crucial negotiation in the development of an IPP. Not only can there be no project if it is not completed, it is also extremely complex and politically sensitive, since it is the PPA that governs the price of electricity delivered to end users. Because of the uncertainty of the bidding process (where applicable) and because of the complexity and sensitivity of the PPA, of the twenty-five or so projects that enter this stage only six or so emerge with signed PPAs.

Once the PPA is signed, the other project agreements can then be negotiated, including those covering engineering, procurement, and construction; lending; operations and maintenance; shareholders; and fuel supply agreements. Also in this stage, licenses, permits, and approvals are obtained. Once these are complete, it is then possible to move to financial closing, which releases funds for the beginning of the construction phase (including engineering and procurement) of the project.

Construction

The construction phase is straightforward. It consists of detailed engineering, site preparation, procurement, construction, and installation. One of the conditions for securing government approval for development of the project might be to use as much local labor and materials as possible. This may also be desirable to gain popular support for the project and to minimize foreign exchange rate risk. The major engineering–construction firms that are likely to be retained by foreign-developed IPPs will usually have sophisticated global procurement networks. Through these networks, they can buy some equipment and materials locally, some on a globally competitive basis and more specialized and sophisticated equipment on a sole-source basis, from a trusted vendor. Standardized power plants, for example, are often designed for specific equipment—such as turbine-generator sets—from particular vendors.

When the physical construction and equipment installation are completed, the plant enters a start-up stage, in which its operational procedures and equipment are tested, and construction and equipment flaws are detected and remedied. At completion of the start-up stage, the plant is certified to be ready for commercial operation and handed over to the IPP.

Operations

This phase is also straightforward. It includes keeping the plant running efficiently and reliably in order to live up to the terms of the PPA and to keep costs at a minimum. It also includes revenue collection or enforcing the terms of the PPA. It is at this juncture that particularly serious problems can occur, as happened with Paiton 1. If the purchaser reneges on the PPA or wishes to renegotiate it, the IPP can hardly pick up its power plant and take it home. Moreover, since the purchaser is usually a monopoly, it cannot sell its power elsewhere. Recourse is confined to the host government's willingness and ability to enforce contracts. The operations phase also includes major repairs and sale, transfer, or decommissioning the power plant.

Allocation of Risks under the Old Paradigm

One of the major features of IPPs is the complexity of risk and its allocation among the stakeholders. In an integrated utility, the interests of the power producer, the electricity purchaser, and the operator are consolidated. If the utility is a government-owned entity, as is the case for all of the countries of developing Asia, the interests of government are also largely consolidated into the utility. In the case of an IPP, however, these stakeholders' interests are separate, and the risks associated with the project must therefore be allocated among them. These risks are many and complex, as shown in Table 1. Since risk allocation is negotiated among the stakeholders, the attribution of risks in this table is no more than a reasonable generalization. In actual projects, the allocation of the risks to the various parties is complex. The general rule is that risks are allocated to those who are best able to control them.

Table 1 distinguishes between direct risks and indirect risks. Direct risks are those that can best be controlled by the stakeholder under whom they are listed. Indirect risks are those that are important to particular classes of stakeholders, but are best controlled by other stakeholders. For example, there can be no greater risk to an IPP than the risk of the purchaser defaulting on the PPA. However, the IPP cannot control this risk. Similarly, the lender cannot control *any* risks, but—since its loans have recourse only to the revenues of the PPA—it is very much at risk for failures of either the IPP or the purchaser to live up to the terms of the PPA. Of course, the fact that IPPs are usually heavily leveraged increases the risk to the lender. The lender is also at risk for currency convertibility problems, because if the IPP cannot convert its revenues into currencies in which the loan is denominated, then the lender cannot be paid. Given that lenders are exposed to substantial risk but control none of it, it is not surprising that they are particular about the sponsors to whom they will lend; the entities with whom the sponsors contract for the IPP's performance; and the political jurisdiction in which the IPP is to be located.

Table 1: Direct and Indirect Risks by Type of Stakeholder in an IPP Project

Stakeholders	Direct Risks	Indirect Risks
IPP	Competition	Purchaser default on PPA
	Technical feasibility	Fuel supply interruption
	Commercial / financial feasibility	O&M performance failure
	Permits / licenses / approvals	
	Political change	
	Interest rate escalation	
	Consequential damages [i]	
	Force majeur [ii]	
	Currency convertibility	
	Default on PPA performance	
	Operations & Maintenance (O&M) cost escalation	
Governments	Statutory change / civil unrest	Purchaser default on PPA [iii]
Purchaser	Inadequate demand	IPP default on PPA
	Inadequate end-use pricing	Commercial / financial feasibility
	Currency depreciation	Permits / licenses / approvals
	Fuel price escalation	
	Political interference	
Lenders		IPP default on PPA
		Purchaser default on PPA
		Force majeur
		Currency convertibility
Contractors	Construction costs	
	Plant performance	
	Timely completion	
	Force majeur	
Fuel Suppliers	Fuel supply interruption	
Operators	O&M performance	
Insurers		*Force majeur*—acts of God
		Force majeur—political risk
		Currency convertibility

[i] Damages that do not occur directly from a breach of contract but do occur as a *foreseeable result* of the breach.
[ii] *Force majeur* is defined as "those risks which result from events beyond the control of the parties" contractual agreements. (Nevitt 1983, p. 19)
[iii] In those cases in which the government has provided a guarantee against default.

Suppliers, including engineer–constructors, equipment providers, and fuel suppliers, have obvious stakes in the IPP being completed and financially successful. Project cancellation, in particular, is a risk for both engineer–constructors and equipment providers. They also take on completion guarantees regarding timing, cost, and operational reliability. Moreover, they have developer/investor risks when they take equity stakes in IPPs.

The magnitude of risks and their allocation are critical for the success of IPP projects. For any project there is some core, irreducible level of risk. If it is too high, it will not survive the evaluation stage. The challenge is for the stakeholders to bring the total project risk as close to the core level as possible through efficient risk allocation and the provision of performance incentives to those who are best able (and willing) to control the project's risk.

It should be noted that not all risks have easily assigned responsibilities. For example, in Table 1 the implicit assumption is that the risk of fuel price escalation is passed from the fuel supplier to the IPP, through the power purchase agreement, to the electricity purchaser. It makes sense for the fuel supplier to refuse to take the risk of price escalation if the fuel price, such as oil, is determined on the world market. But why should the IPP accept this risk, since it has no control over world oil prices either? And why should the purchaser? It is such "homeless" risks that provide some of the most difficult negotiation issues in developing the IPP. Other examples of homeless risks are currency depreciation, interest rate risk, high inflation, and macroeconomic collapse that results in collapse in the demand for electricity. The stakeholders control none of these, and they are not insurable as *force majeur* casualty losses or as *force majeur* political risks. Thus, they constitute a kind of "economic *force majeur*."

Disagreements over who takes what risks—particularly those which are not clearly assignable to one or another of the stakeholders—are undoubtedly a major factor in many projects failing to survive the development agreement and PPA negotiation stages of development. They remain major factors in disputes even after a project is constructed, as with Paiton 1 and the Hubco 1 project in Pakistan (a 1,300 MW plant owned by a consortium of National Power (UK), Xenal (Saudi Arabia), and Mitsui Corporation), which is also under fire for allegations similar to those made about Paiton.

Bids vs. Negotiation

The discussion above has not yet covered the issue of how the parties of a PPA-based project are brought together. There are two basic mechanisms: competitive bidding and direct negotiation. Competitive bidding, in principle at least, is fairer and more efficient. The basic premise of bidding is that the power purchaser knows how much power it needs and is capable of evaluating complex bids. Given this knowledge and capability, it advertises for bids from developers and selects the winning bid to provide power at some combination of acceptable reliability and low cost to end users. Economic theory leaves no doubt that competitive bidding is the most efficient solution, since the competitors will have an incentive to provide the most attractive bid, subject to the constraint of adequate profits. Moreover, competitive bidding is, in principle, less vulnerable to corruption, given that bidding systems in which the low bidder takes all are understandable and relatively transparent.

In the case of direct negotiation, the would-be developers of the IPP approach the power purchaser with a proposition to build a plant and deliver power at a specified price. The developers and the power purchaser then enter negotiations on specific terms and conditions.

One major disadvantage of direct negotiation is that without competition the purchaser cannot be sure that it is receiving competitive-equivalent terms from the IPP. Another is that, since the negotiations are typically not open to the public, they are subject to suspicion that they are corrupt. Despite these disadvantages, though, many IPPs are agreed as a result of direct negotiation, which suggests that the virtues of competitive bidding, while formidable, may sometimes be partially or even completely outweighed by other factors.

Complexity of Bid Requests

Many developing countries may not have the technical and financial staff expertise necessary to prepare precise bid proposals. The power purchaser must know exactly what it wants with respect to the plant's location, capacity, fuel, and other physical parameters, as well as the financial terms it will accept. Otherwise, evaluation of the bids received may lead to the selection of an IPP proposal unsuited to the power purchaser's real needs. If the purchasers' needs become clear only in the process of project development, it may lead to time-consuming and expensive changes.[16] In addition, competitors who might have presented bids closer to what was ultimately decided would feel that they had been badly treated. Thus, they hey might protest the award and be reluctant to present bids for future projects.

Transparency May Be More Apparent Than Real

Because requests for bids are complex, there is ample opportunity for corruption and other suboptimal behavior in evaluating them. In some cases, projects are repeatedly rebid. In some instances, rebidding is undoubtedly due to flaws in the original request and the discovery that what was bid is not really what the purchaser wants. In others, it appears that the project is rebid until the right firm is the winner.

Bid preparation Is Expensive and Risky for the Bidder

For successful competition, there must be many bidders. This implies many losers. Since bid preparation is expensive, time-consuming, and risky, many developers may choose to deploy their resources elsewhere. This is particularly true for two kinds of developers: those who are highly successful and have global opportunities, and those who are relatively small and inexperienced in operating in a particular country. The large companies focus on markets in which the development costs and risks are smaller, and in which the expected profit is therefore higher. The smaller companies will find the costs and risks of bid development to be unacceptable, given that they are operating in an unfamiliar business environment.

Negotiation Can Be Faster

In principle, direct negotiation should be faster than a process that involves the preparation of bid requests, the response to those requests, selection of a winner, and negotiation of final terms. If a project is ill-defined, under direct negotiation developers can bring their expertise to bear to define it in a way that is responsive to the power purchaser's needs. If all goes well, speed can be a major advantage for direct negotiation where it is desirable to bring additional capacity online as soon as possible. However, if all does not go well—and the lack of transparency in the process is perceived to be the results of corruption, favoritism, or other chicanery—negotiations can take even longer than a competitive bidding process and perhaps cause the deal to fail completely. This was almost the case in the Dabhol project, about which the Secretary of the Indian Ministry of Power, M.P. Abraham, had this to say: "If competitive bidding had been used from the beginning it might have resulted in some delays. Yet that would have caused less damage to the power policy than the criticism over the lack of transparency." (Sader 1999, p. 43)

In the end, means of project selection are only as honest as the participants want to make them. If the participants are corrupt, they will corrupt the process. If they are honest, direct negotiation can be clean and efficient. Competitive bidding may make corruption less prevalent and also carries with it an image of transparency. However, it is likely that enthusiasm for competitive bidding as a system that promotes honesty and transparency varies inversely with direct experience.

All things considered, it would seem that the balance tips in favor of competitive bidding over negotiation, but not by nearly as much as theory suggests. Before launching into a PPA-based IPP, the pros and cons of each selection process should be considered.

The Old Paradigm's Archetypal Disaster Scenario

One archetypal disaster scenario for the Old Paradigm emerged prominently in developing Asia in 1998 and 1999. It consists of the following elements:

- A severe contraction of the economy, leading to less demand for power than the purchaser is committed to buy under the PPA;
- Serious foreign exchange rate depreciation, coupled with an agreed tariff in the PPA that is tied to the investor's national currency;
- A power purchaser that is pressed to insolvency by the high local currency cost of the PPA and declining demand due to the economic crisis;
- A central government guarantor whose finances have deteriorated due to revenue loss from the economic contraction, the foreign currency costs of external debt, and pressing needs for expenditure to relieve the misery caused by the contraction;
- Political change that overthrows the regime responsible for the IPP and its PPA.

The results of this disaster scenario are:

- End users' hardship due to the economic contraction is compounded by rapidly escalating local currency tariffs;
- Power purchasers cannot live up to the terms of the PPA due to lack of expected demand;
- The IPP does not earn enough revenue to cover its loans, much less a return on equity;
- A new government insists that the project be renegotiated or canceled because of alleged stakeholder misdeeds before it came into power;
- The central government cannot or refuses to live up to its contingent liabilities;
- Lenders (having recourse only to the IPP's assets) acquire bad debt.

Bottom line: the ship sinks with all hands.

The Old Paradigm's Archetypal Optimal Scenario

Because of the 1997–98 experience, when economic distress and currency depreciation were the hallmark of the countries of the Association of East Asian Nations (ASEAN) and others, the focus has since shifted to the dangers of the traditional PPA, as manifested in the disaster scenario above. This shift notwithstanding, it should be noted that under conditions of prosperity, the PPA has significant potential advantages. Here is what the stakeholders look forward to when they reach an agreement:

- Robust economic growth implies that the purchaser will take all the power the IPP can produce. The take-or-pay provisions of the PPA are binding on the producer as well as the purchaser. Thus, if system demand growth outstrips capacity expansion, the purchaser with a PPA still has stable supply at a price that is less than it would be under short-term competitive conditions.
- If the host country's economy is strong, there is a good chance that the exchange rate will appreciate. If that is the case, exchange rate indexation will cause the local currency value of the indexed component of costs to fall, resulting in lower local currency electricity price escalation relative to domestic inflation.
- The power purchaser is financially healthy.
- The central government's guarantees are not called upon.

The results of the optimal scenario are:

- End users have a secure, reliable source of power and competitive, predictable tariffs.
- Power purchasers have no trouble meeting the terms of the PPA.
- The central government's income statement is not affected by the contingent liabilities on its balance sheet.
- The IPP repays all debt in a timely manner and earns a good return on equity.
- Lenders are repaid in full.

Bottom line: the ship sails on, with a happy crew.

V. The Merchant Power-Based Independent Power Project—the "New Paradigm"

"Merchant power" is power sold on a spot market. It is the key element in the New Paradigm, which aims to achieve short-run competitive markets, shifting risk to the investor/developers and lenders of the private sector. They, in turn, will presumably price this additional risk and incorporate it into their willingness to provide additional capacity and the financing necessary to support it. Under this paradigm, IPPs and electricity purchasers do not sign long-term agreements. Rather, the price and quantity of electricity generated and delivered depends on short-run (i.e., hour, day, week) market conditions. Through the New Paradigm, the production and sale of electricity are like any other capital-intensive industry that produces a commodity. However, as discussed below, the transition from the Old Paradigm to the New is important, difficult, and entails significant costs. Establishment of merchant power is a necessary, but by no means sufficient, condition for a New Paradigm that will function better than the Old.

The attraction of merchant power from the perspective of overall market efficiency is that supply and demand are matched continuously. There are no situations in which electricity purchasers are contractually bound to buy more power than they can use, or at a price that is higher than the price that would clear the market. By the same token, individual electricity purchasers are not guaranteed to have a supply of power at a contractually based price. Without the protection of a PPA, it is possible that individual electricity purchasers will be forced to purchase less power than they want, and to pay more in spot markets than if they had contractually locked in supply. This aspect of merchant-power based systems has been frequently overlooked by enthusiasts of the New Paradigm.[17]

The New Paradigm includes the following elements:

- De-integration of transmission and distribution into a system-wide transmission entity and many distributors (those who purchase from the IPPs).
- IPP developers that are large enough to be able to manage risk through a diversified portfolio of investments.
- IPPs that sell power on a competitive spot market rather than through PPAs.
- Private distribution entities that are free of central government interference, motivated by profits, and therefore efficient. Such entities will be shrewd enough to avoid disadvantageous PPAs and instead buy power from IPPs on a competitive spot market.
- A transmission system, and its related institutional development, that enhances rather than inhibits efficient transactions between IPPs and purchasers.
- Purely commercial transactions between private entities that eliminate the government's role in providing commercial guarantees.
- Solid macroeconomic policy, along with fair and efficient financial and regulatory laws and institutions, that provide healthy economic growth and foreign exchange stability. This reduces the need for governments to undertake guarantees concerning foreign exchange rates, interest rates, transferability, etc.

To date, there are no merchant power plants in developing Asia. However, Figure 1 shows that few are being built under the Old Paradigm either. If IPPs are to be built in developing Asia then, is it possible that merchant power is the wave of the future? The question hinges on the institutional development necessary to support the New Paradigm.

Market Structure of the New Paradigm

The basic model of the New Paradigm is perfect competition: many buyers and many sellers with complete information adjusting quantity continuously, with price equal to marginal cost. No one is under any illusions, however, that producing and delivering electricity is the same as, for example, raising and selling onions in peasant agriculture. There are three critical differences. One is that power generation is capital-intensive. A second is that power generation investments are "lumpy." That is, they can only be built efficiently in units that cost tens of millions of dollars and have a long gestation period. The third is that the transmission system is a necessary intermediary between IPPs and purchasers.

Capital intensity implies that IPPs must be assured that they will be compensated in some way for their fixed costs, or they will not undertake the investment. Generation plants are lumpy in that they take several years to plan and build and, to be of efficient size, may have large capacities relative to the incremental demand that they intend to serve.[18] This implies that—given the relatively small or poorly connected grids that are characteristic of developing countries—there may be periods of excess demand or excess capacity. In a simple market-clearing system, when conditions of excess demand prevail, IPPs will receive high prices and rents. In conditions of excess capacity, they will be driven to their short-run marginal costs.

Under the Old Paradigm, transmission was integrated with distribution as part of a single purchaser. Under the New Paradigm, transmission assumes a separate identity that creates a number of complexities. Of particular interest in the present context is how the transmission system functions as a stakeholder in IPPs. Important questions arise over the rules under which power goes from the IPP to the customer; the arrangements for compensation for transmission services; and arrangements for compensation of the IPPs if the proceeds from sales to purchasers flow through the operator of the transmission system.

A thorough discussion of the role of transmission would be long, complex, and tangential to the main focus of this paper. A good, brief discussion of alternative transmission arrangements and their major strengths and weaknesses may be found in Kennedy (1999, pp. 7-11). Suffice it to say here that how the transmission system is organized and how well it functions are critical to the success of the New Paradigm. A minimum condition is that it be sufficiently extensive and integrated to accommodate enough IPPs and purchasers to create the conditions for a competitive market.

Another major change from the Old Paradigm is that the purchasers are now private entities, competing with one another to buy power on the most advantageous terms. The purchasers can be utilities that own the distribution system and have a monopoly franchise (presumably regulated) for a given region. They can be marketers who purchase power and resell it on a competitive basis in several regions, and pay the owner of the physical distribution system for the system's services. They can also be large single customers, such as an industrial plant.

Direct Stakeholders and Project Life-Cycle of the New Paradigm

For the most part, the stakeholders and their roles under the merchant power paradigm are the same as in the conventional PPA-based IPP structure shown in Figure 2. However, the differences are critical. Figure 4 shows the stakeholders in a merchant power-based IPP commercial structure in a modified and simplified version of Figure 2. The differences are that the provider of transmission services becomes a stakeholder and a major player, and that there are many power purchasers rather than just one. Moreover, as discussed above, the power purchasers are likely to be private rather than public entities.

One of the advantages of a merchant power commercial structure is that it enables the development process to be greatly compressed. In particular, the time that would be spent in negotiating a PPA is eliminated.

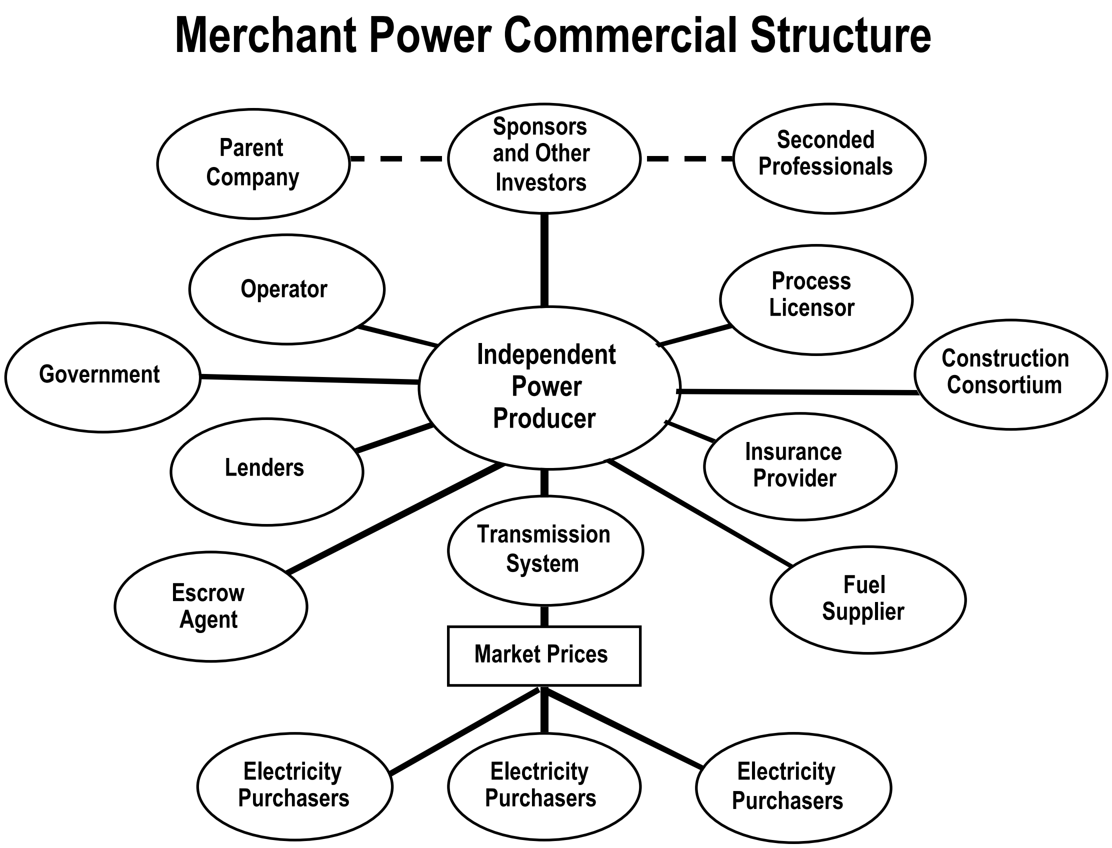
Allocation of Risks under the New Paradigm

While most of the risks associated with merchant power are the same as those presented in Table 1, the most critical difference between a PPA-based commercial structure and a merchant power commercial structure is in the allocation of risks. In particular, in the absence of a PPA, all *negative* market risk (market risk caused by less demand/more supply than expected) reverts to the IPP and its lenders. *Positive* market risk (caused by more demand/less supply than expected) is pushed on to the purchaser, who may or may not be able to pass it on further to end users. Thus, the merchant power structure is similar to normal free markets for commodities.

Negative Market Risk

In a PPA-based structure, the IPP is assured of a stream of earnings whether or not there is excess capacity in the electricity system as a whole. Thus, it is protected from negative market risk. Lenders are also protected from negative market risk by having recourse to the revenues generated by the project under the PPA. Negative market risk in this case is taken on by the purchaser, and perhaps by the central government if it offers a guarantee.

Figure 4



Under a merchant power structure, the IPP suffers the consequences of system-wide excess capacity. At worst, it will not be able to sell power at even its short-run marginal cost. Moreover, the stream of revenues may be insufficient to repay lenders for the project's debt financing. Under merchant power, lenders as well as sponsors therefore undertake increased risk. However, unlike IPPs, all consequences of market risk are negative for lenders. Loans or debt are incurred under fixed terms, and lenders cannot share in the realization of favorable market conditions. The differences in risk profiles between lenders and IPPs may mean that lenders are reluctant to lend to merchant power projects that are supported enthusiastically by sponsors, unless the lenders have recourse both to the sponsors' balance sheets and to the IPP's revenues.

Positive Market Risks

In the PPA-based structure, positive market risk is taken on by the IPP, which foregoes monopoly rent afforded by high demand/low supply conditions. It should be noted, though, that the pain the IPP suffers in realizing positive market risk covers only "what might have been"—there is no actual financial loss. Purchasers and lenders are not exposed to positive market risk.

In the merchant power-based structure, the purchaser and ultimately the end user—who must pay higher, market-clearing prices—take on positive market risk. If the risk is realized, the IPP extracts monopoly rent, as in California in 2000–01.[19] Unlike the consequences of realizing positive market risk for IPPs in the PPA-based structure, purchasers and end users in the merchant power-based structure suffer real financial and welfare losses. As observed above, lenders do not share IPPs' benefits from positive market risk.

Other Risks

In addition to the risks of excess supply of capacity, the IPP is not protected against foreign exchange rate risk under the merchant power-based structure. Market-clearing prices are obviously in local currency, so depreciation of the local currency in the presence of significant foreign exchange debt may leave the IPP—and its lenders—in a precarious position. Protection against local currency depreciation is usually built into PPAs. However, like market risk, foreign exchange risk can swing the other way. If the currency appreciates under the merchant power structure, there will be a windfall for the IPP.

Privatizing the purchasers does not eliminate the risk of nonpayment for the IPP. How to handle the risk of private purchasers who cannot or will not pay, regardless of overall market conditions, is an issue that the IPP must resolve. Does it have the legal right to decline to sell power on the spot market to a particular customer? How the transmission system is organized plays a critical role here. If the transmission system serves as a transactions intermediary, how does it allocate the losses of purchasers' nonpayment? In developing countries in particular, it may be politically difficult to cease serving a large industrial customer that refuses to pay its bills, given the employment impacts that would ensue from loss of electricity service and closure of the plant.

In short, negative market risks under the New Paradigm are reallocated to sponsors, project companies, and lenders, and away from purchasers and governments. This is appealing to those who represent citizen and government interests (such as the multilateral development banks), as well as those who believe that this paradigm will result in efficient, competitive markets. However, it is less clear that the risks are acceptable to sponsors and lenders. If they are not, the obvious economic logic of the New Paradigm will be irrelevant in the face of market realities.

As of California's experience has shown, *positive* market risk cannot be ignored. Here risk is shifted from the IPP to the purchaser and, ultimately, to the end user. These risks are more likely to be realized if sponsors perceive the damaging consequences of negative market risks to be greater than the beneficial consequences of positive market risk, because sufficient new capacity will not developed. Moreover, lenders are exposed to negative market risk but do not benefit from positive market risk, thus biasing them against financing in which negative market risk is significant, regardless of positive market risk.

The New Paradigm's Archetypal Disaster Scenarios

There are two disaster scenarios for the New Paradigm.

Excess Capacity

- The economy contracts severely, leading to less demand for power than contemplated by IPPs.
- Market-clearing power prices fall.
- Serious foreign exchange rate depreciation occurs.
- Power purchasers are pressed to insolvency by declining demand and inability to collect revenue on that electricity which is sold.

The results of this disaster scenario are:

- End users' hardship in an economic contraction is mitigated by rapidly falling local-currency electricity prices.
- IPP revenue loss, already hit by falling demand, is compounded by rapidly falling local currency electricity prices.
- Local currency revenues are further reduced in home currency terms by the depreciation in local currency.
- Power purchasers cannot pay the IPP for power that is purchased because of the lack of expected revenue.
- The IPP does not earn enough revenue to cover its loans, much less a return on equity.
- Lenders (having recourse only to the IPP's assets) acquire bad debt.

Bottom line: Only end users catch a lifeboat. The government, having taken on no contingent liabilities, is only a spectator in this drama.

Excess Demand (The California Case)

- Sustained growth in electricity demand is acted upon slowly by IPP sponsors, and excess demand becomes a serious problem. Moreover, long lead times between project inception and power generation imply that the problem will persist for several years.
- Market-clearing prices rise to unacceptable levels, putting an enormous burden on end users and causing the economy to decelerate.
- Full-capacity production and high prices lead to enormous IPP profits.

Bottom line: IPPs are temporarily happy, as are their lenders. By contrast, end users and politicians see the situation as: "Foreign fat-cat robber-barons stealing from widows and orphans and destroying the jobs of honest workers."[20] Political pressure rises to dismantle or distort competitive electricity markets. Government becomes a major player to protect end users from "exploitation."

The New Paradigm's Archetypal Optimistic Scenario

- The economy and electricity demand are fairly predictable, so that large imbalances do not arise between demand and generating capacity.
- Market clearing prices are no higher than they need to be to attract capacity growth, so there is no persistent excess demand or excess capacity.

Unresolved Questions Concerning the New Paradigm

The New Paradigm raises a number of questions. One of the foremost is the role electric power plays in the development of countries whose economies are largely pre-industrial. It has been forcefully contended that the positive externalities of increasing power supplies—particularly to poor people in poor countries—are significant. In particular, as long as the marginal social benefits of electrification exceed the marginal private revenue and marginal social cost (including private cost), the New Paradigm will result in underinvestment in electric power relative to what is socially optimal. If power is sold purely on the basis of a private market, what mechanisms will have to be put in place (and by whom) to insure that the socially optimal generating capacity prevails? In other words, who will undertake the expenditure for new capacity that is implied by the gap between marginal private revenue and marginal social benefit?

The World Bank, the Asian Development Bank, the Inter-American Development Bank, and national development assistance agencies have provided significant financial support to public-sector electric power development. This, too, suggests a belief that positive externalities play a larger role in the social value of a power plant than, say, a soft drink bottling plant or a petrochemical complex. Thus, due to the presence of externalities, government might be a more important player in the private provision of electric power capacity than is suggested by the New Paradigm.

A second question concerns the institutional conditions of the New Paradigm. Will they permit private electric power development in most developing countries? Faulty macroeconomic management and inadequate laws and institutions in general are hallmarks of underdevelopment. If countries had remedied these problems, they might no longer be underdeveloped.[21] Reform to eliminate these problems involves far bigger stakes than electric power and has proven to be very difficult. For example, mechanisms to insure macroeconomic stability include reform of the financial sector and macroeconomic management that maintains confidence in the local country's currency. Otherwise, since there is no provision for foreign exchange depreciation in rates determined by local conditions of supply and demand, the risk to foreign investors in merchant power development will be high. The prevalence of subsidies in developing Asia is another institutional barrier to the market-based New Paradigm that transcends the power sector. Although a case can be made for subsidies, they must transparent and efficient. In general, the New Paradigm cannot be effective unless it operates in an environment that focuses on the efficient working of the private sector, rather than tolerates it as a necessary evil.

A third question is whether the experience of developing countries in the post-1997 period indicates the need for a New Paradigm. Would macroeconomic events have impacted private power had the New Paradigm already been in place?

Thus, as attractive as the New Paradigm appears to be, it may still have serious problems. Determining which paradigm will emerge—if indeed any one paradigm will dominate—involves serious research to disentangle the various forces that have impacted FDI in private power in the post-1997 period. This would seem to be a precondition for identifying the contractual and institutional arrangements that can best balance the objectives of all stakeholders in the IPPs of the future.

VI. Questions Concerning the Interpretation of IPP Experience in the Post-1997 Record

The previous discussion should make two points clear. First, there are serious problems in the Old Paradigm, particularly as it has been applied to developing Asia to date. Second, the number of unresolved issues in the New Paradigm is sufficient to raise doubts about whether its theoretical superiority can be translated into actual superiority. A key requirement in going forward is to understand what has happened over the past few years. There is no question that the Old Paradigm has been tarnished by this experience. Would the New Paradigm have fared better?

What Happened?

One of the first issues that must be addressed is the extent of project failure associated with FDI in IPPs in developing countries in the post-1997 period. Project failures—in the sense of severe damage to at least one of the classes of stakeholders—are by no means unique to this period. However, these failures did not reach a sufficiently intolerable rate as to threaten the entire Old Paradigm market, as has been suggested by the post-1997 experience. What is less clear is whether project failure is systemic, occurring throughout developing countries, or whether it is limited to relatively few high-profile cases, such as those in Indonesia and Pakistan. It is also unclear how many new projects have succeeded under the Old Paradigm in the post-1997 period.[22]

The Role of Economic *Force Majeur* in the Failure of Old Paradigm IPPs

One of the key questions concerning FDI in private power in developing Asia in the post-1997 period is whether investment under *any* paradigm could have withstood the economic contraction set off by the East Asian currency crisis.[23] For the IPPs that failed because purchasers could not meet the terms of the PPAs, the crisis might be regarded as the macroeconomic equivalent of *force majeur*. Certainly, the macroeconomic conditions (including exchange rate depreciation) that befell several countries of East Asia seem to conform to the definition of *force majeur* as "those risks which result from events beyond the control of the parties" to IPP agreements. (Nevitt 1983, p. 19)

If it is reasonable to regard the collapse of compliance with the PPA terms as a result of economic *force majeur* (EFM), then it is perhaps premature to pronounce the Old Paradigm to be inferior—much less fatally flawed—to the New. The collapse, after all, was due to events beyond the control of the contracting parties. Of course, the difference between the Old Paradigm and the New (or investment in productive capacity in any other industry) is that the Old assigns market risk to the purchaser, and the New assigns it to the IPP and its lenders. EFM breaks down this distinction because the purchaser is not able to comply with the PPA. Thus, the IPP and its lenders bear the consequences of market collapse under either paradigm.

Although the concept of *force majeur* typically pertains to events that trigger insurable casualty losses (such as natural catastrophes) and some insurable noncasualty losses (normally related to political and social disturbances), it also seems functionally related to economic events. Three major types of EFM come to mind:

- **Severe foreign exchange rate depreciation**, as experienced by Indonesia, Malaysia, the Philippines, South Korea, and Thailand in 1997 and Brazil in 1999;
- **Catastrophic macroeconomic conditions**, such as declines in year-to-year growth rates of real GDP of 10 percent or more, and/or severe inflation, as happened to several of the countries mentioned above;
- **Unpredictable structural change**, such as the United States' intense focus on energy efficiency in the wake of the two 1970s oil shocks, and the backlash against nuclear power after the Three-Mile Island event in 1979.

Conventional *force majeur* risks tend to be project-specific, uncorrelated with one another, and therefore insurable, either through formal insurance purchases or self-insurance by diversification. EFM, however, is systemic on a national, or even a multinational basis. Insuring against it—whether through purchased insurance or self-insurance—would seem to be more difficult. One issue for the future, irrespective of the paradigm, is who takes EFM risks. Another is how to compensate sponsors and lenders if EFM does strike, allocating costs and benefits equitably and efficiently to all stakeholders. The issue of moral hazard would also have to be dealt with in order to avoid encouraging sponsors and lenders to invest in countries that appear to be particularly vulnerable to an EFM event.

The experience of the United States in the 1980s, with regard to reactions to "rate shock," affords some insight on how to cope with EFM. In that situation, electricity customers were called upon to pay for expensive power plants, which were not needed, due to an abrupt deceleration of demand. A simplified account of this situation is as follows:

- In the wake of the first oil shock in 1973–74, electricity demand slowed significantly from the "ten-year doubling rate" (7 percent per year) of the previous decades—thought by utility executives and regulators to be virtually a law of nature—to slow growth (2–3 percent per year) thereafter.
- Utilities were building power plants, which have long gestation periods, in anticipation of 7 percent per year growth. Many of these were nuclear plants, which have especially long gestation periods, as well as high capital costs. Several were started after 1974 because it was believed that the slow growth of the mid-1970s was an aberration.
- The Three-Mile Island event in 1979 triggered a wave of new nuclear safety requirements that caused expensive delays and retrofits to nuclear plants, both those in existence and those under construction.
- The utilities and their regulators had a compact which ensured that utilities would be able to recover their capital costs, plus a reasonable rate of return on investment, as long as such investment was deemed to be "prudent."

Reasonably stable electricity prices depended on predictable capital costs and a high rate of capacity utilization. Neither of these conditions obtained in the early 1980s because of the EFM events of structural change in demand and escalating construction costs of nuclear power plants. The result was rate shock.

Although it would be inappropriate to draw facile parallels between two countries and circumstances as different as Indonesia and the United States, the two countries nonetheless have three common ingredients:

- **Rate shock** (due to foreign exchange depreciation in Indonesia and rising capital costs in the United States), which arises from the requirement to pay for heavy fixed investment costs;
- **Excess capacity**, due to inability to anticipate lower-than-expected demand, which in turn resulted from macroeconomic factors in Indonesia and structural change in the United States;
- **Inadequate revenue,** on the part of those who invested in new capacity in both countries.

What lessons can be learned from the United States' experiences in the 1980s that would apply to countries impacted by rate shock? Are there reasonable ways to mitigate the damage, such as changes in the timing of revenue recovery? What is the proper role of government? Of multilateral institutions? Investigation of successes and failures in the United States with respect to rate shock would provide productive suggestions for improving the situation today, and for structuring agreements in the future.

Scenarios from other times and places notwithstanding, what mechanisms can or should be incorporated into an emerging paradigm for FDI in private power in order to mitigate the potential damage of EFM? Who is best able to bear EFM risk? How should that risk-bearing be structured? Would the projects that have failed in the face of post-1997 EFM have done so regardless of how they were structured? Would the only difference in the outcome be a shift in the allocation of risks? The failed projects might not have been built under the New Paradigm, nor, perhaps, would others, successful or not. Would that outcome have been preferable? While the repercussions of post-1997 continue to play out, it is time to investigate what happened and the lessons to be learned.

The Role of Structural Failure of the Old Paradigm

One of the questions that should be addressed is whether the Old Paradigm actually broke down at a greater rate in the post-1997 period than before. If so, does this suggest fatal structural flaws, or simply that projects were overwhelmed by EFM? One way to shed some light on this question is to conduct research on what has happened to FDI in IPPs in countries (such as India, China, Mexico, and Taiwan) that did not suffer as seriously as many East Asian countries during the financial crisis. Are projects still successful in the sense of all stakeholders being satisfied under the terms of their agreements, or impacted only by risks that they voluntarily assumed and that are at least partially under their control? A comparison of FDI in IPPs in crisis and noncrisis countries, at similar stages of economic development, would be appropriate and illuminating. If projects under the Old Paradigm are proceeding in noncrisis countries, then it suggests that the paradigm is not the principal problem.

VIII. Scenarios for the Emerging Paradigms

The future of FDI in IPPs is uncertain. To illustrate the possibilities, nine scenarios have been devised, as shown in Table 2. These have been drawn from the sponsors' perspective, given that sponsors are the driving force in IPP projects. These scenarios result from a combination of macroeconomic and political factors. Macroeconomic growth drives the demand for power and hence for new capacity. Tariff margins can be the result of either bidding or negotiation for PPAs under the Old Paradigm, or of market conditions in the New. Risk depends on a number of factors, including the predictability of economic growth, the maturity of institutions to enforce contracts, whether there are strong PPAs, and whether third parties provide guarantees.

Table 2: Scenarios for IPPs in Developing Countries

	A Nice Place to Visit … • Low demand growth • High tariff margins • Low risk [i]	**Good Gain, Little Pain** • Moderate demand growth • High tariff margins • Low risk	**Developer Heaven** • High demand growth • High tariff margins • Low risk
Risk-Adjusted Rate of Return	**Picking Up the Crumbs** • Low demand growth • Significant risk–reward trade-offs	**Worth Serious Thought** • Moderate demand growth • Significant risk–reward trade-offs	**Some Pain, Much Gain** • High demand growth • Significant risk–reward trade-offs
	Developers Need Not Apply • Low demand growth • Low tariff margins • High risk	**Fools Rush In …** • Moderate demand growth • Low tariff margins • High risk	**Can't Afford to Not Be There** • High demand growth • Low tariff margins • High risk
		Percent Increase in Generating Capacity	

[i] The main elements of risk are macroeconomic stability, the presence or absence of strong PPAs (and the will and ability to enforce them), and the provision or withholding of third party guarantees.

The top row might be considered the extreme of the Old Paradigm: highly profitable PPAs (probably negotiated rather than bid), with low risks to developers and lenders (but high contingent liabilities for guarantors), and stable political and economic conditions. The bottom row might be considered the extreme of the New Paradigm: competition holding down margins, with high risks to developers and lenders (but low or nonexistent contingent liabilities for guarantors). The middle row characterizes all the combinations of profitability and risk that can exist between the two extreme cases. For example, for a given generating station, an IPP might have PPAs with a few major customers for a significant amount of the station's capacity and sell the rest at spot-market quantities and prices.

These nine scenarios are an attempt to cover the range of possibilities, but some are clearly more plausible than others. For example, "Developer Heaven" might be so attractive to developers that power purchasers and/or governments would adjust and offer less attractive tariffs and/or shift risk from themselves and still have an adequate number of developers competing for the available capacity. However, governments could decide to sustain "Developer Heaven" for a while to ensure that they have enough qualified bidders to meet their capacity needs. In the opposite corner, "Developers Need Not Apply," there would be little reason for developers to show any interest. Any new capacity added in this environment would probably have to be publicly owned, regardless of official policy. In general, the lower left of this table would be unlikely to attract many developers. In the upper right, governments and purchasers might question whether they are offering too rich a deal.

Of the other extreme positions, "Can't Afford Not to Be There" may be realistic. If a market is big enough, developers may be willing to take significant risk in order to establish footholds that may prove to be profitable in a less risky future. For FDI in general, China is often cited as such a case. The "Nice Place to Visit…" scenario is realistic in that, while its low growth may not warrant sustained marketing and business development, it is an environment that is attractive on an opportunistic basis.

With respect to the future of FDI in private power, how far upward and/or to the right must environments be to attract development that will be supported by lending? Until developing countries regain sustained economic growth, the answer to this question will remain uncertain. What is certain is that all stakeholders—developers, purchasers, lenders, governments, and multilateral development agencies—must have a much clearer idea of their own and one another's interests if FDI in private power is to achieve the private and social potential of which it is capable.

VIII. Concluding Observations

There is a clear need for FDI in power sectors of developing Asia. However, the stakeholders are many and their objectives complex and conflicting. To achieve success, the interests of all stakeholders must be reconciled. It is not clear that the Old Paradigm of IPPs based on long-term PPAs is an efficient, viable way of accomplishing this in developing countries, although they have been relatively successful in developed countries. The Old Paradigm has been severely criticized, and some Old Paradigm projects have run into serious problems, even after they were in operation. This has led a number of observers to believe that their flaws are fatal.

Given that developing Asia needs FDI to construct the generating capacity necessary to support economic growth, is there a realistic alternative paradigm? This paper has explored strengths and weaknesses of the PPA-based paradigm and those of a proposed alternative paradigm based on privatization of distribution systems and increased competition in power generation and distribution. It has also raised a number of questions that should be addressed by new research. Such research would lead to deeper knowledge of how well the Old Paradigm has worked and how it can be improved, along with a more precise knowledge of what is required to make the New Paradigm a robust option. The elements of such a research program are described in the Appendix to this paper.

It may be the case that improving the Old Paradigm is a more realistic and less risky possibility in much of developing Asia than moving quickly to the New Paradigm and its accompanying dangers. It may be also be possible to develop transition strategies that retain the goal of New Paradigm efficiency and provide workable paths to getting there.[24]

Appendix: Key Issues for Research on Emerging Paradigm(s)

Whatever paradigm emerges will have to address a number of considerations to succeed in attracting FDI, having agreements hold together without creating undue distress to end users, and avoiding unacceptable contingent liabilities for governments.[25] This section raises some of the issues that will have to be addressed if FDI in electricity generation in developing Asia is to realize its potential.

How can Risks be Allocated Efficiently to Stakeholders?

Sponsors: Sponsors must be able to obtain an acceptable risk-adjusted rate of return. This simple truth masks a number of complicated issues. One is the role of portfolio diversification. It has been suggested that large, multinational investors can accept lower returns than might be implied by the riskiness of a given project on a stand-alone basis. However, given the size of IPP investments, how many corporations are large enough to have more than a few in their portfolio? Reliance on large, multinational firms runs the risk of having fewer firms than necessary for effective competition in any given market. Moreover, the size of an IPP investment typically means that even large corporations develop special-project companies that are deliberately isolated from the balance sheets of their parents. Thus, while an IPP project may look like one among many investments by a large corporation, functionally it is one of a few. In fact, it may be one of a kind in a special-purpose company formed by its large parents.[26] Even if large multinationals regard an IPP as one among many of its investment portfolio, to what degree would the sheer size of the projects limit the number of players who could look at them from this perspective?

Risk adjustment of returns sought by developer/investors also implies that the nominal returns, and therefore the costs to transmission and distribution (T&D) entities and end users, are higher if the owners take more risks. Thus—under the Old Paradigm—guarantees in one form or another allow supplied capacity to be greater and tariffs lower. The cost of guarantees, however, is that the risk is shifted from the sponsor to the guarantor. Not all countries are willing to provide guarantees against market risk, even under the Old Paradigm. Under the New Paradigm, guarantees against market risk are not applicable. An unresolved question is how important guarantees or other risk mitigation measures are for attracting foreign investment in electricity generation.

Purchasers: Purchasers (for the most part distribution companies) in developing Asia are state-sponsored, often with little independence from political direction or pressure. In addition, they are also often placed in a position in which they are the executors of political and social objectives through subsidization of tariffs of particular classes of end users and are constrained from raising overall tariffs to a level that will cover their costs.[27] Granting long-term PPAs to IPPs puts such T&D entities in an uncomfortable—and sometimes untenable—middle ground between their obligations under the PPA and political pressure from end users and their political representatives to keep tariffs low. The result is purchasers (such as the Indian State Electricity Boards) that lack the financial strength that would assure sponsors and lenders that they can live up to the terms of PPAs. However, if sponsors and lenders refuse to assume the risks associated with PPAs, investors may also be unwilling to take the market risk associated with a merchant plant. As a consequence, power supply would be inadequate.

Another issue is whether public T&D companies have the incentives and the expertise necessary to negotiate equitable agreements with sophisticated multinational companies. On the one hand, it is thought, the naiveté of such entities leads them to negotiate agreements that are unfavorable to their end users. On the other hand, fear of being exploited may keep them from negotiating *any* agreements that might interest developer/investors, leading to end users not having power supply that they would be willing to pay for. Whether the privatization of T&D entities would make a major difference in the amount of capacity supplied by IPPs, the terms under which is supplied, and the revenues necessary to entice it remains an open question.

End users and regulators: End users and regulators seek power supply that is some combination of available, reliable, and cheap. Although institutionalization of competition is increasing at the retail level, end users' interests are typically represented by regulatory bodies or by state-owned distribution companies. One issue is how well end users understand the trade-offs between "available and reliable" and "cheap." Another is how well their interests are protected, either by state regulatory intervention or by a completely competitive market. The latter may entail sufficient risk for end users, in that developers will provide less than the socially optimal investment in generating capacity and at a higher price.

Governments and multilateral development agencies: Governments and multilateral development agencies are important stakeholders in that they may be guarantors, lenders, or investors—or all three. In addition, they are perhaps the most efficiently responsible entities for identifying and coping with externalities. Governments and multilateral development agencies as investors have many of the same considerations as private developer/investors, as discussed above. (The interests of lenders are discussed below.) In addition, however, governments may have conflicts of interest between their responsibility to represent the public good, and their roles as investors seeking the maximum return on investment, or lenders seeking an agreed return. To the extent that they do represent the public good, their objectives may conflict with those of their private partners. How do government and multilateral development institutions reconcile these conflicting interests?

As indicated above, the presence of externalities means that the marginal social benefits of electricity supply may often exceed the marginal private benefits and marginal social costs, particularly for pre-industrial agriculture and the urban poor. Insofar as this is the case, application of private investment criteria will lead to undersupply of new generating capacity. In addition, government has a role in correcting for negative externalities of electricity supply, such as air pollution.

The issue of positive externalities implies economically justifiable subsidization, a burden often forced on state-owned utilities, rather than borne by general government. If utilities are forced to provide subsidies, particularly cross-subsidies between different types of customers, the result is inefficient pricing. Also, cross-subsidization is not transparent—another reason that general government should be responsible for compensating positive externalities. Given this, how likely is it that the burden of subsidies can be shifted to where it belongs?

Who Takes Economic *Force Majeur* Risks?

During the 1997–99 period, virtually no developing country in Asia was untouched by financial contagion and the damage to real economies that it caused. Although such a period may never recur, the fact that it happened once will intensify future concern over EFM and how to determine which stakeholders should bear EFM risk.

A general principle of risk allocation is that risks should be borne by those who can best control them.[28] Who controls EFM risk? As far as macroeconomic and exchange rate stability risks are concerned, these can only be controlled, even in principle, by central government. Yet, at the onset of the East Asian financial crisis, those countries most affected were pursuing what appeared to be sound fiscal and monetary policies. The principal problems came from the *private* sector's borrowing too much, in the wrong currencies, and with mismatched time structures of borrowing and lending. In retrospect, better prudential regulation of the financial sector by central governments might have prevented the crisis, but it did not seem to be a major consideration at the time. So, who could have controlled this risk to IPPs and who should have taken it? Similar questions were asked in the 1970s, in the wake of the sudden slowdown of electricity demand with regard to investor-owned utilities in the United States. Allocating EFM risk will be an important issue in the future, and it is by no means clear how it will be handled.

How Will Externalities Be Handled?

The principles for handling externalities are fairly clear. Making these principles operational is another matter. First, the nonmarket nature of externalities makes them extremely difficult to measure. Thus, invoking externalities when a project fails a market test may be either a legitimate concern, or the first refuge of scoundrels. Potential externalities should be identified and quantified as far as possible. To the extent that they cannot be quantified, they can at least be subject to relatively transparent political judgment. At a minimum, whatever subsidies are appropriate to compensate for externalities should be decided using the best information that can be documented.

Of course, externalities can be simply ignored, but they will not go away. Ignoring them simply gives them an implicit value of zero. If they are real (albeit unmeasurable) then private investment in IPPs will be less than optimal insofar as marginal social benefits exceed marginal social costs, as discussed above. In other words, if power supplies are to be adequate, the public sector will have to invest more than if an appropriate compensation scheme been in place.

The obvious next question is what is "an appropriate subsidy compensation scheme?" An answer to this question must meet two important criteria: it must be economically efficient, and it must be amenable to implementation.[29] Unfortunately, it appears that both of these criteria are seldom met, with considerations of implementation frequently dominating considerations of efficiency. The most common subsidy compensation scheme, as mentioned above, is subsidization and cross-subsidization of rates by T&D entities. The result is almost certainly economic inefficiency due to distorted relative prices, perhaps compounded by the inefficiency of financially insolvent T&D entities. Some other possibilities are:

- Direct government payments to the IPP to meet its revenue requirements, in return for lower wholesale tariffs (with the attendant perception of a poor government subsidizing rich multinational companies).

- Direct government payment to members of the classes of end users deemed to be appropriate targets of subsidization.
- Government payments to the distribution utilities.

One clear principle is that compensation for externalities should be a general government, and not a utility expense.

Is Busbar-to-Meter Competition a Sufficient Condition for IPPs to Provide Adequate Capacity at a Reasonable Price?

An important element of the New Paradigm is private competition from the generating station's busbar (the interface between the power station and the transmission system) to the ultimate customer's meter. The leap from their current situation to complete privatization would be enormous for most developing countries. Although IPPs are common, wholesale transactions solely through spot market transactions, to completely private, unregulated, competitive retail marketers, are not. So far, experience is neither wide nor deep enough to come to any firm conclusions, but the experience of California suggest that caution is in order. In particular, it is not clear how enticing it will be for developer/investors to operate in a spot market.

A precondition for a perfectly competitive market is many buyers and many sellers. On the one hand, sponsors will not develop a plant in a monopsonistic situation without the protection of a PPA. On the other, if there is not enough capacity in place to satisfy demand, merchant plants can price as monopolists, until other sponsors enter the market. However, the threat that political intervention would prevent them from so doing could put a cap on tariffs (and therefore returns). This situation would expose them to downside risks (part 1 of the Disaster Scenario, described above)—leaving merchant plants in a quasi-regulated regime that compares unfavorably to conventional regulation in the United States. The only way out of this box is to have a transmission system that would physically allow merchant plants to sell to many buyers and to have the institutional mechanisms in place for smooth, efficient transactions. The countries of developing Asia fall short of both conditions. The challenge, then, is structuring an environment for IPPs that would maximize the advantages of competition, subject to the constraint of sufficient incentives for sponsors to add capacity.

Can PPAs Be More Flexible without Causing Unacceptable Damage to Some Stakeholders?

One possibility that should be explored for future PPAs—if, indeed, there will be PPAs under whatever paradigm emerges—is whether there are ways to add flexibility to their terms that can better accommodate EFM. For example, current rate shock and/or utilities' revenue deficiencies might be mitigated in return for larger-than-otherwise tariff increases in the future, when macroeconomic and electricity demand conditions have recovered. U.S. experience with rate shock and addressing utility revenue requirements in the 1980s might shed some useful light on available options. How California adjusts in the aftermath of the rate shocks of the summer of 2000 might also offer some insight. [30]

Is Privatization of Distribution Necessary or Sufficient for Efficient Provision of IPP Service?

Privatization of distribution utilities has important theoretical advantages over publicly owned entities, in terms of incentive-driven efficiency that approaches conditions of perfect competition. The theoretical appeal is enhanced by the generally poor record of publicly owned distribution in many, if not most developing countries. However, given other priorities and political opposition, it may be some time before many developing countries give serious consideration to privatizing distribution. When they do, they will carefully balance economic benefits with potential political costs. One topic that should be examined is whether the problem lies with public ownership *per se* or with difficulties that can be remedied in a public-sector framework.

In the United States, for example, public ownership of distribution appears to be alive and well in the entire state of Nebraska; in major cities such as Los Angeles, Seattle, San Antonio, and Sacramento; in a number of smaller cities; and in over nine hundred rural electricity cooperatives. While it is true that many have access to inexpensive, government-sponsored generation and their own generation, many have also added incremental capacity through agreements with IPPs. They do not seem unduly inefficient and appear financially solid. The difference between these distribution entities and those of developing countries lies in governance, incentives, and competence. In the United States, these entities are typically independent of short-term electoral politics, required to be financially self-sustaining, and have managed to attract adequate expertise.[31] Is corporatization, but not privatization of distribution, enough to insure efficiency? There seems to be more rhetoric than evidence on this point.

Moreover, privatization of T&D companies may simply shift corruption and political influence, not remove it. Until sophisticated institutional arrangements are in place to give each retail customer a choice of IPP or some marketing intermediary from which to purchase electricity, distribution utilities will remain in monopoly positions and thus have to be regulated. Even then, it will still be necessary to regulate the physical distribution system over which marketers move power to end users. Regulators are likely to be subject to the same political pressures and temptations as publicly owned distribution utilities.

Thus, while publicly owned distribution systems may be no more effective than private distribution, they need not be worse. The possibility that reformed public distribution (now taken as an intermediate step in many developing countries' plans) may be adequate to represent end users efficiently in forming agreements with IPPs should not be dismissed automatically. However, careful institutional design would be necessary to shield publicly owned distribution companies from corruption and political influence.

Notes

[1] Cited by Industry Canada (1998). V. Bakthavatsalam (1997) estimates about $62 billion per year. Other estimates appear higher but are not easy to compare because they include some developed countries.

[2] "Financial closing" is the event that marks the beginning of the project: all financing, licensing, and other agreements and permits have been obtained, and work on the construc-

tion of the project can commence. Financial closings tend to overestimate actual FDI flows, since some projects are canceled. Also, financial closing predates major plant and equipment expenditure, which is typically spread over several years. (Data source: World Bank's Private Participation in Infrastructure (PPI) database.)

[3] Sader (1999, p. 9) found that from 1990 to 1998, on a worldwide basis, over 90 percent of all private power projects in developing countries had foreign sponsorship, and 86 percent of actual investment flows was contributed by foreigners.

[4] Financial closings may overestimate actual flows, but anecdotal information suggests that the investment "requirements" were not being met either.

[5] In this paper, "power"—as in Power Purchase Agreements—and "electricity" are used interchangeably.

[6] It is important to distinguish between "privatization"—the sale to the private sector of publicly owned existing assets—and "greenfield" development of private generation capacity.

[7] The reasons are often complex. In particular, because of perceived intrinsically desirable (merit goods) aspects of electricity, state-owned utilities are reluctant to charge market-clearing prices, which may be quite high—particularly if (as is often the case) there is far less generating capacity than would be necessary for the markets to reach a competitive equilibrium. However, if inability to finance is simply a matter of utilities not being able or willing to generate sufficient revenue to meet competitive equilibrium conditions, IPPs are as likely to be a problem as a solution. The conditions necessary to support IPPs are explored later in this paper.

[8] However, IPP developers and lenders often ask for sovereign guarantees in case of default on PPAs by the state-owned utility. If these are granted, they typically become unfunded contingent liabilities on national government balance sheets. See Lewis and Mody, chapter 6 in Irwin et al, 1996.

[9] Convertibility risk is the risk of not being able to convert local currency earnings into another currency. Transfer risk is the risk that transferring earnings abroad will be blocked, regardless of whether the currency is convertible.

[10] There are many types of arrangements, and they can be quite complex. Sader 1999 (pp. 3-4) has a good capsule summary.

[11] In an orderly realm of depreciation and inflation, it would be expected that power prices indexed to domestic inflation would provide a natural hedge, inasmuch as domestic inflation tends to offset depreciation. That is, as exchange rate depreciation decreases the foreign currency value of local revenues, inflation increases the revenues. The question is whether the increase in local currency revenues is adequate to offset the decrease in the value of the currency. As a practical matter, lenders and many investors are risk-averse and prefer exchange rate indexation.

[12] There are many other factors being disputed in this project, including allegations of corruption and undue pressure on the utility from the central government to sign unfavorable contracts that would benefit friends and members of the Suharto family.

[13] See Razavi 1996, p. 69 for brief descriptions of a number of these agencies.

[14] See *http://www.miga.org/welcome* for more information.

[15] Some observers have commented that the conditions in most of rural America in the 1930s, particularly in the South, were not so different from those prevailing in the rural sector of developing countries today.

[16] Due to the complexity of power generation projects, selection of a winning bidder is only the first step in negotiation of the final deal, in which all stakeholders are satisfied.

[17] California in 2000-01 is a case in point. Electricity prices rose about three-fold over a short period in the San Diego region. In Northern California, statutory price caps have kept prices from following suit. As of January 2001, two major distribution utilities, PG&E and Southern California Edison, were facing bankruptcy because the statutory price caps were less than the wholesale prices that prevailed on the spot market. There have also been rotating blackouts. Exactly how this situation came about is the subject of ongoing investigation. What is clear, however, is that clearing the market in the short run—as opposed to the certainty of long-term contractual agreements—has contributed to high-priced power delivered to end users.

[18] The IPPs that reached financial closing in developing Asia between 1994 and 1999 had a mean capacity of about 300 megawatts (MW) and a cost of about $1 million per MW. (World Bank PPI database)

[19] The situation in California in 2000–01 is a classic case of positive market risk that cannot be passed on by distributors.

[20] A rough approximation for some of the language used by end users, politicians, and nongovernment organizations (NGOs) in California in 2000–01.

[21] Singapore and Hong Kong are examples of impoverished entities that have become prosperous by developing laws and institutions that foster prosperity.

[22] The financial closing data from the World Bank's PPI database do not cover what happens after closing. Was the generating plant actually built? Did the parties live up to the terms of their contracts?

[23] One trait that makes electricity especially vulnerable is that it is not tradable beyond the extent of its transmission system. In developing countries, the transmission system is seldom well developed even within national borders, much less across them. Thus, it is not possible to mitigate the effects of economic downturns by exports.

[24] Dossani and Crow (2001) suggest a sequence that appears to be an efficient way of making such a transition for India.

[25] Given the diversity of interests and conditions among projects, it is unlikely that any single paradigm will completely dominate, but there is a good chance that one will be pre-eminent.

[26] In India's Dabhol project, for example, the owners are Enron, Bechtel, and GE Capital.

[27] India's State Electricity Boards, now a target for reform, have been an outstanding example.

[28] In fact, some stakeholders' risks may be so big that strict application is infeasible. For example, engineering and construction are inherently risky. In some projects, if engineer–constructors took all design and construction risk, the result might be either an exorbitantly high risk premium built into their bid, or simply be too risky to make any bid at all.

[29] Dossani and Crow (2001) present the formal conditions for economically efficient subsidization.

[30] At the time this paper was written, this seemed to be the direction to be followed by California. A prominent proposal was for the state to buy bonds from the distribution utilities, which would use the proceeds to forestall bankruptcy and repay them from surcharges on future electricity prices.

[31] It is often said that following this course in developing countries is not possible, given the level of political interference and corruption. However, many municipal utilities in the United States were formed in or went through periods characterized by corruption and improper influence, yet managed to survive and serve efficiently. The Los Angeles Department of Water and Power, for example, first started delivering power in 1917.

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