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Viewpoint

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The Impact of IPPs in Developing Countries—Out of the Crisis and into the Future

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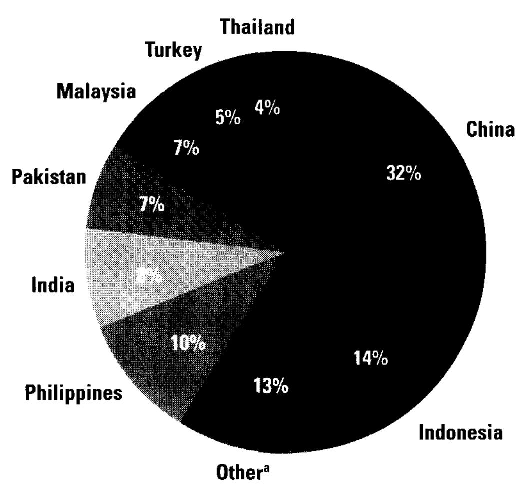
Developing countries started opening their power sectors to independent power producers (IPPs) some ten years ago, and IPPs have now developed into a large market. This Note examines several contentious questions relating to the development of this market: Has risk been transferred to the private sector, or have IPPs contributed to an increase in government liabilities? Have IPPs contributed to an increase in foreign exchange exposure? Are pricing and investment decisions efficient? Have IPPs contributed to sector modernization? Answering these questions has become more pressing with the global financial crisis. The Note concludes that on the whole IPPs have had a positive development impact. But negative effects become significant when the IPP program quickly grows to a large size relative to the host grid capacity, as has happened in a few Asian countries.

FIGURE 1 THE IPP MARKET

Distribution of IPP investment among selected developing countries, 1997



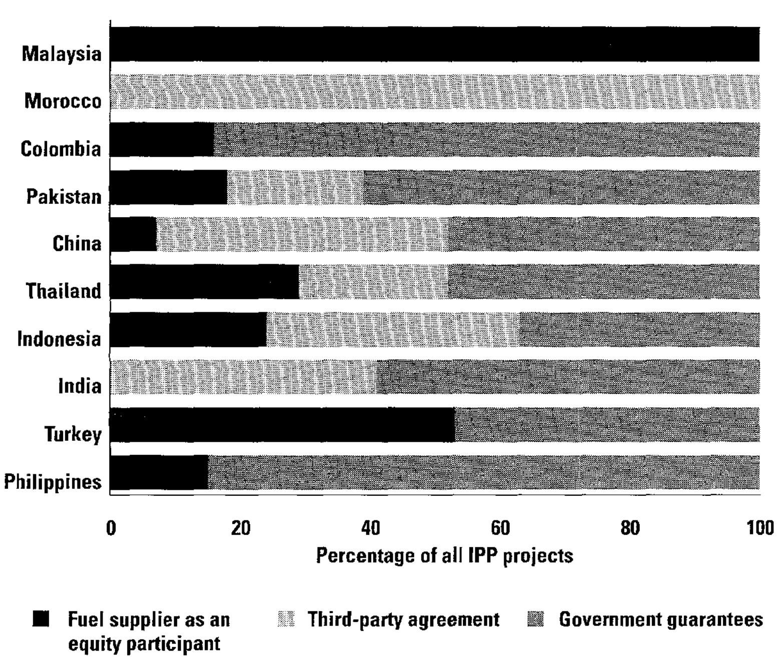
Note: Data are as of end-December and cover only IPP projects of more than 100 megawatts.
a. Argentina (3 percent), Chile (2 percent), Colombia (2 percent), Morocco (2 percent), Czech Republic (1 percent), Lao PDR (1 percent), Mexico (1 percent), and Peru (1 percent).
Source: World Bank, Energy, Mining, and Telecommunications Department, Knowledge Management database.

Greenfield expansion—the source of IPP projects—has been an important area of private investor participation in the power sector, though not the only one. Of the US$131 billion of private power projects contracted in 1990–97, greenfield investment accounted for 56 percent, most of it for generation (Izaguirre 1998).

The IPP boom occurred in 1992–96, when the volume of private power projects financed was three times that in all previous years. Growth waned somewhat with the East Asian crisis in 1997, but large contracts are about to be awarded in Bangladesh, Egypt, India, and Vietnam. From 1991 through 1997 the firm market (contracts brought to a close) for large greenfield IPPs consisted of 137 projects for 67 gigawatts (GW) of capacity worth US$65 billion. IPPs mobilized US$51 billion in private funds. The balance consisted of guarantees or credit enhancements: 5 percent of the total from multilateral development banks, 11 percent from export credit agencies, and 7 percent from bilateral donors. The guarantees and enhancements went to project finance deals, which represent about 55 percent of the IPP market (Babbar and Schuster 1998). (These figures exclude projects under 100 megawatts [MW], which account for about 10 percent of the market. Small IPPs tend to generate for the grid only in small systems; elsewhere they generate "within the fence"—that is, provide captive generation for large consumers.)

Asia has the lion's share of the IPP market, with 103 contracts worth US$54 billion. Latin America is a distant second, with 28 projects and US$6.6 billion. In Asia the IPP business is concentrated in seven countries—China, Indonesia, the Philippines, India, Pakistan, Malaysia, and Thailand—all of which have experienced rapid economic growth, a backlog of unmet demand for power, or both. In Latin America IPPs have emerged mostly in the liberalized sectors of Argentina, Colombia, and Chile (figure 1).

FIGURE 2 FUEL SUPPLY ARRANGEMENTS FOR IPPS, 1997



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Source: World Bank, Energy, Mining, and Telecommunications Department, Knowledge Management database.

Local state-owned utilities are IPPs' minority shareholders in Malaysia and majority venture partners in a score of Chinese projects. IPPs generally sell to single, state-owned buyers through a power purchase agreement (PPA), although in Latin America they sell mostly short term to many, privately owned off-takers at the going pool price.

The impact of IPPs

The following analysis focuses on the ten largest markets less Argentina—that is, the seven Asian countries plus Turkey, Morocco, and Colombia; together, about 85 percent of the market. Absent a global financial crisis and compared with generation by state-owned utilities, the opening of the market to IPPs has raised a number of questions.

Has risk been transferred to the private sector?

An analysis of the projects in the ten countries shows that IPPs have allowed the transfer of a significant share of project risks to the private sector. IPPs have accepted construction and operating risks, and they share fuel availability risks for 52 percent of the IPP market—by signing third-party agreements for 31 percent and by enlisting the fuel supplier as an equity holder for 21 percent (figure 2). Most IPPs are compensated for fuel price variations, and recovery of their fixed costs is protected against market risks by take-or-pay contracts or capacity charges. Except in Malaysia, currency risks are covered by denominating prices in, or indexing them to, hard currencies. IPPs are also protected against political risks—including regulatory ones—often by explicit government guarantees. These risks are passed on to the off-taker, but for 20 percent of the market off-takers also own the IPP.

On balance, IPPs make a significant difference in many countries by covering construction, operating, and fuel availability risks; less so in the few cases where state-owned utilities have a good track record, as in Thailand, or have already transferred construction and operating risks through turnkey procurement and leases or through concession contracts.

Have IPPs increased sector exposure to foreign exchange risks?

External debt finance and fuel imports can have a significant impact on foreign exchange exposure. IPP projects have been highly leveraged, with an average debt-equity ratio of 76 to 24 (figure 3). By contrast, for many state-owned utilities internally generated cash has accounted for 25 to 40 percent of their investment funding, often at the World Bank's insistence. As with most state-owned utilities, most of the IPP debt is offshore (80 percent on average), borrowed from a small pool of banks that face limits on exposure to clients, sectors, and countries. Local capital markets have provided sizable debt finance only in China, Malaysia, and Thailand. Equity is held mostly by a few global developers (30 percent), engineering, procurement, and construction contractors (22 percent), and local industry (20 percent).

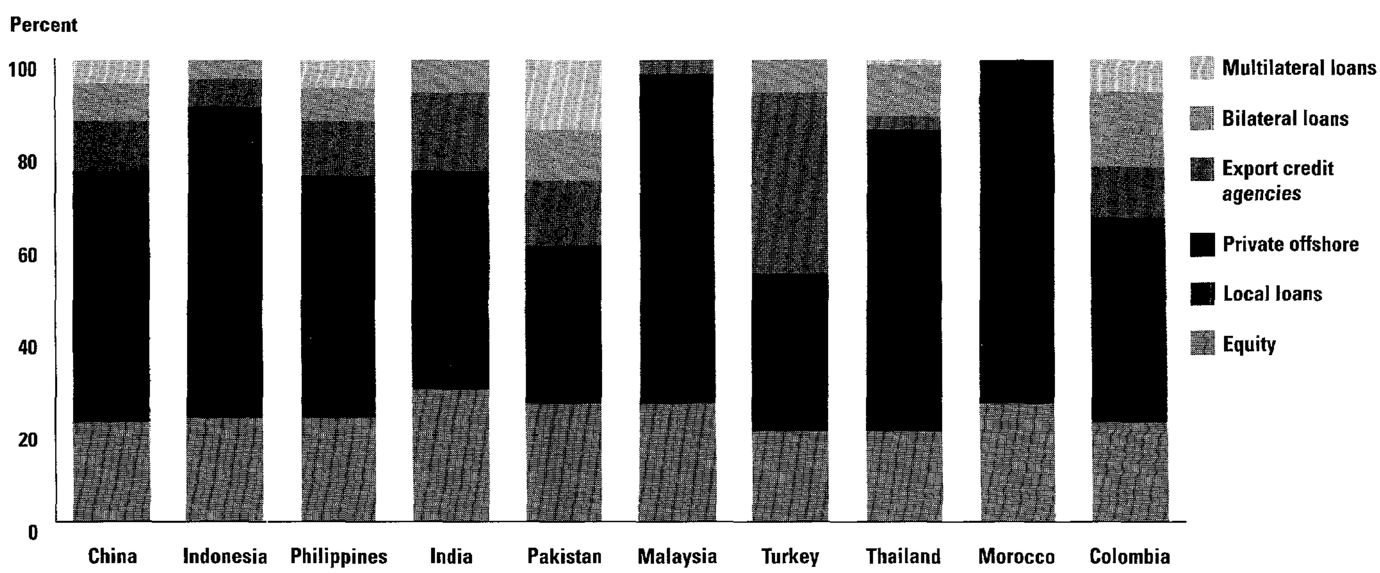
IPPs rely overwhelmingly on fossil fuel, which typically accounts for 50 to 70 percent of total operating costs. Imported petroleum-based fuels account for about 11 percent of IPP capacity. For Pakistan, which has indigenous gas and hydro resources, this share is 74 percent, a serious departure from the least-cost plant mix even at favorable exchange rates.

In general, the sector's exposure to foreign exchange risks has stayed the same or increased with IPPs. But in a few countries the power sector's foreign exposure is likely to be higher with IPPs than under expansion plans centered on state-owned utilities. That exposure can be risky if the IPP program is large, as is the case in Pakistan.

Have IPPs relieved capacity shortages?

Some fifty-two projects have been commissioned in the ten countries, for a total capacity of 24 GW. Most of these have reduced or eliminated shortages, whether blackouts (as in the

FIGURE 3 SOURCES OF IPP FINANCING, 1997



Note: Data are as of end-December and cover only IPP projects of more than 100 megawatts.
Source: World Bank, Energy, Mining, and Telecommunications Department, Knowledge Management database.

Philippines) or, more often, pent-up demand. Sudden blackouts can cost developing countries about US$1,000 per megawatt-hour (MWh), and planned outages up to US$300 per MWh when alleviated by small diesel generators or as low as US$120 per MWh with judicious load shedding. Without the IPPs, state-owned utilities would have been able to finance and build less capacity, and valuable demand would have gone unmet. In such cases the investment by the IPPs would be offset by benefits in ten years or less.

But too much was signed too soon in at least three countries, with the result that some IPPs did not reduce outages and merely inflated reserve margins. In Indonesia and Malaysia IPPs have only displaced expensive generation and brought fuel savings (US$10 to US$20 per MWh) too small to justify the investment. In Pakistan, even discounting the recent economic downturn, IPPs have contributed 1,000 MW of excess capacity run on expensive fuels. In many countries part of the capacity meets wasteful demand induced by poor cost recovery, mostly in agriculture. Without the IPPs, most of the overcapacity would not exist.

Have IPPs hiked the price of electricity?

The true picture is partly obscured because the opening of the market to IPPs has led to a cut in capital cost subsidies to the sector. IPPs finance most of their debt on commercial terms, with short maturities (eight to twelve years) and interest rates well above LIBOR. In contrast, state-owned utilities often borrow long or refinance at subsidized interest rates and always with a government guarantee at no charge. Furthermore, the state-owned utilities' cost reflected in the tariffs is often only a fraction of what a regulator would allow in a market-friendly environment, and it is unclear whether development costs are accounted for and internalized in the capital costs.

Analysis of capacity costs for IPPs shows that they vary widely, even for similar technologies: the average price of gas turbines in China is 40 percent that in Indonesia. Moreover, IPPs' capacity costs are sometimes higher than those achieved by state-owned utilities with World Bank financing. In addition, PPAs often include take-or-pay quotas—a costly straightjacket when demand for plant output is weak. In China strong demand led to a windfall for a few IPPs, which charged the same high price to cover capacity costs for power above and below the quota.

In the final analysis it appears that IPPs have often inflated supply prices for utilities. In the Philippines the average generating cost for IPPs in 1996 was US$76 per MWh, compared with US$57 for the state-owned utility. Although reliable cost data are lacking for many state-owned utilities, the price shock can be assessed by comparing the range of prices for the largest IPPs with sales tariffs. Even when averaged over the life of the PPA, these prices often exceed the bulk tariffs and are so high relative to retail tariffs that they leave little or no margin to cover distribution costs. While price shocks of that magnitude are not unique to IPPs, they test utilities' capacity to recover costs. The response has often been to minimize—or to sidestep—unpopular rate hikes for the many residential and agricultural customers while overcharging commercial and industrial users. But cross-subsidization is nearing its limits in many countries as overcharged customers start to evade grid supply or payment, thus shrinking the revenue base.

Have IPPs improved sector institutions?

In theory the arrival of IPPs could strengthen sector institutions through competition, technology transfer, and the introduction of greater transparency and flexibility.

With commissioned IPPs now accounting for 5 to 60 percent of the host grids' peak demand, they have broken the monopoly and—in Malaysia, Pakistan, and the Philippines—the dominance of the state-owned utilities in the generation market. IPP proponents see this change as an important entry point for the private sector and in many cases the first feasible step on the road to sector liberalization and reform. About half the IPP contracts are build-operate-own (BOO), and half are build-operate-transfer (BOT). In structuring these contracts governments and utilities have become more familiar with private investors, their demands, and the financial engineering of deals. Legal frameworks, insurance systems, and accounting rules have been modernized. And as important, the risks and costs of IPP investment have been more realistically assessed, have become more transparent, and have been clearly allocated, a sharp contrast from practice in the public sector.

Projects in Latin America and East and South Asia have introduced new technologies for plant regulation and environmental management, for improving efficiency with new gas turbine and combined cycles, and for using low-quality coal and gas. In China technology transfer is significant for a few very large IPPs, but often limited by the heavy involvement of local companies in the construction and operation of the plants.

In many cases efficiency and transparency have been wanting in project development. Compared with state-owned utilities, IPPs are supposed to accelerate project gestation. They have managed to do so in a few cases (such as in the Philippines). But even excluding the first IPPs in countries unprepared for this type of foreign direct investment (India, Indonesia, Pakistan, and Turkey), transaction costs have tended to be high, and elapsed times to financial close generally more than two years (the median is four to six).

The development of the IPP market has been accompanied by allegations of corruption and price padding. One reason for these allegations is that prices have varied widely across and within countries. Another is that rules for the solicitation, award, and close of contracts have been unclear and onerous, have allowed opportunities for graft, and have been perceived as unfair by sponsors losing out to competitors. PPAs can hamper efficiency in system operations and sector liberalization. Even if all the output can be freely dispatched, PPA prices deviate from those provided by a competitive pool—prices that are the same for all generators, a capacity charge smaller than that of a base load IPP, and time-varying energy charges. The potential for inefficiencies is substantial if the IPPs meet a large share of the load; for example, PPA prices provide no incentive to maximize the availability of base load IPPs in the periods when supply costs are highest.

In the long run PPA prices and contractual rigidities may prove costly whenever IPPs lose competitiveness following technical progress and access to cheap gas or hydro. The resulting stranded assets may complicate unbundling and reduce revenues from privatization unless these obstacles are removed in due course, as they were in the United States. The main challenge is in Asia, the host of most IPPs, where sector reforms have yet to be made.

Emerging lessons

Three main lessons are emerging from the IPP experience.

Performance of government

Governments' resource planning performance and frequent recourse to bidding are key to ensuring the quality of IPP projects at entry. Governments still originate requests for IPPs, and their recourse to IPPs does not guard against overcapacity. The pricing and guarantees—and the vested interests and political considerations pushing for closure of ongoing negotiations—limit the mechanisms for market corrections. Governments also often retain a great deal of control over fuel price and availability.

Bidding seems to have reduced PPA prices by 25 percent on average, but exceptions are numerous and important (see figure 4). Capacity costs were lower in China without bidding than they were in the other nine countries, even for imported technologies. Where a pricing formula has been used, it has failed to reduce lead times and allegations of corruption. Bidding has tended to be neutral on lead times and to reduce corruption allegations.

Performance of distribution utilities

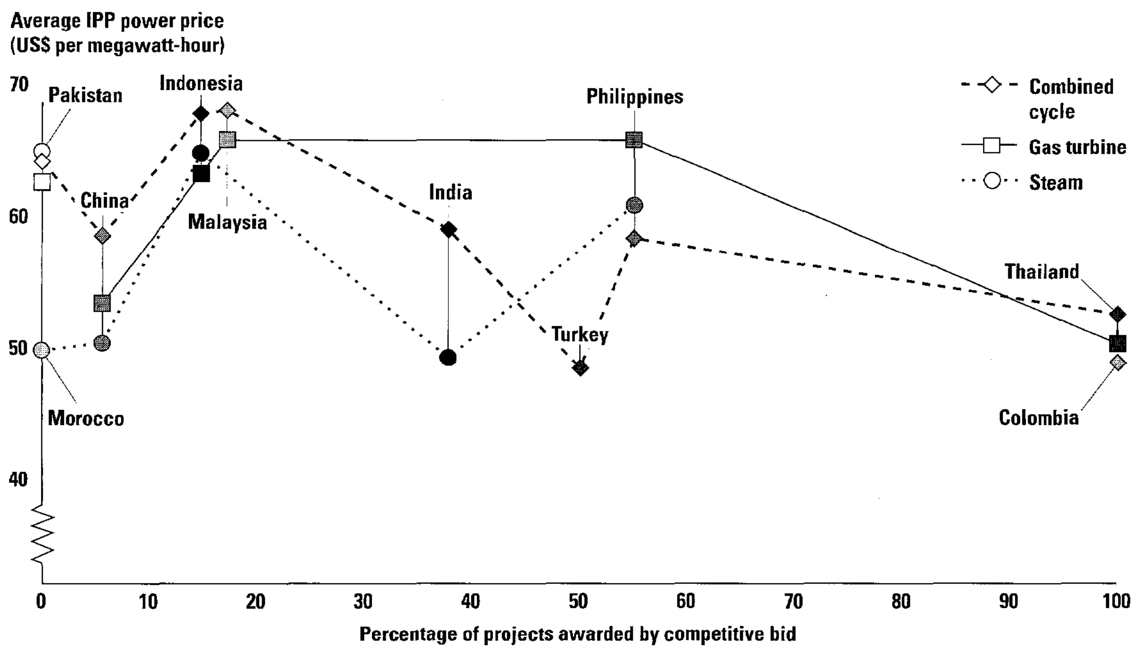
Inefficient state-owned distribution utilities and politicized tariffs are bad for IPPs because governments cannot afford to mitigate the market risks that they create in the long run. In comparison with privately owned distribution utilities, state-owned utilities have a bad track record for technical and nontechnical losses. If unchecked, large losses stemming from unpaid arrears trigger a spiral of nominal increases in tariffs and further collection problems. Broad subsidies fuel exaggerated market growth, and the cross-subsidization makes this growth lopsided and unsustainable. The money-losing market segment is large—30 to 50 percent of the total in India and Pakistan—and growing faster than the money-making segment. With that kind of growth, there is a risk that nontechnical losses will increase even for the best state-owned utilities. Decades of experience worldwide has shown the best approach to be private ownership of distribution and restriction of price subsidies to lifeline consumption for the poor.

Contingent risks and capital structure

In some countries IPPs have proved so attractive to bankers that the challenge now is to manage the liabilities contracted by governments and to improve the financing terms of private generation.

The IPP experience has shown that competition does not ensure financial efficiency if government exchange rate guarantees make the cost of loans much greater than the private cost to sponsors. With high debt-equity ratios, currency depreciation can make borrowing more expensive than internal cash generation and

FIGURE 4 BIDDING FREQUENCY AND IPP POWER PRICE, BY TYPE OF TECHNOLOGY, 1997



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Source: World Bank, Energy, Mining, and Telecommunications Department, Knowledge Management database.

other forms of equity. (The World Bank recognizes this fact when it makes internal cash generation and debt-equity ratios the subject of covenants in power sector loan agreements, implicitly prompting countries to regulate the sector's capital structure. In the United Kingdom the regulator exercises this option indirectly in the setting of price caps.)

In contrast to balance sheet financing, project finance can mobilize little equity. And since it offers lenders mostly downside risks, they subject it to a minute assessment and allocate these risks conservatively. In general, the larger the IPP program, the greater the recourse to offshore lenders and the greater the need for governments to improve risk assessment and pricing by lenders and investors, to increase the share and lower the cost of equity financing, and to increase the share of local capital markets.

Out of the crisis and into the future

While countries such as Pakistan are undergoing crises of their own, it is the East Asian financial crisis that casts the darkest shadow over the power sector. With the economic contraction, demand is expected to fall significantly in some countries. The currency collapses have caused power costs to skyrocket because of their high foreign exchange content. The crisis also restricts access to foreign funds and threatens to dry up capital markets.

While prescriptions for the future vary with each country, the common prescription must be to improve the climate for private generation by strengthening sector cost recovery, developing local capital markets, and optimizing sector capital structure.

Privatization becomes more urgent. Even the relatively efficient state-owned utilities in East Asia lack the technology and the flexibility to undertake drastic cuts in investment, particularly in generation; to adopt aggressive demand-side management to maximize revenues; and to shed or redeploy redundant physical assets and workers. Distribution services should be privatized too—if not the wires, at least supply.

Beyond these steps, the best strategy is to liberalize the market, allowing entry by different kinds of IPPs and marketers to compete in a pool and grow a business with many plants and off-takers. Even in the United States, where IPPs were first conceived, the need for competitive pools is now recognized, and old PPAs increasingly are being discarded in favor of merchant plants or arrangements in which marketers are assigned the PPAs. Merchant IPPs and marketers accept market downsides but retain upsides on fuel and market expansion (plants can be built without soliciting bids). And they can diversify their risks through access to several off-takers, whether in the same pool or in interconnected pools. But off-takers must be creditworthy, the generation market must be restructured, and open access to the grid must be permitted. As the United Kingdom and the Latin American reformers show, this is a first-best solution for bringing prices down while maintaining appropriate levels of private investment. These countries also demonstrate different ways to get there, both sophisticated and simple. And Latin America shows that fundamental reform can be achieved under crisis conditions.

An alternative is to move gradually toward the first-best solution by improving on the current IPP model. In this improved model competitive bidding would be the rule. Transaction costs would be minimized by standardizing documents where possible. Governments would assess and track contingent liabilities more precisely to improve management and budgeting for these liabilities. The system operator would be left free to dispatch all the output, because many unpredictable events—changes in demand or prices, and grid and environmental constraints—can change plants' merit order over the life of a PPA. Demand risks would be partly allocated to IPPs, for example, by allowing long-term contracts for only part of the capacity, with the balance to be sold at spot prices. The premium—if any—that IPPs would charge as a result could be minimized in several ways: through least-present-value-of-revenue auctions for BOTs; through risk hedging—such as a contract for differences adapted to country conditions; and by granting upsides to the IPPs, for example, on energy prices. PPA pricing would be based on marginal costs. Experience shows that it is easy to set pricing formulas based on marginal costs with sufficient accuracy for medium-term contracts. With prices set, the bidding would be based on such nonprice factors as contract length or the present value of revenues. Finally, future changes in sector conditions could be accommodated in several different ways. PPAs could be for shorter periods or could be reassigned to new off-takers under predetermined circumstances, and clauses could be included that trigger a review of the risk allocation when warranted.

The moral hazard implications of any bailout would extend far beyond the public sector. In the past the costs of crises in state-owned utilities were fiscalized into a public deficit problem, with the remedy a sector bailout financed by taxpayers and donors. But the presence of IPPs should facilitate market-based solutions and heighten the odds of a workout rather than a bailout. While respect for contracts is a critical foundation of private sector development, IPPs in trouble may have to be restructured, though only as a last resort and in ways that move the sector closer to the first-best solution. For example, IPPs may accept larger price cuts, payment delays, and market risk if given replacement deals. Where applicable, a global settlement for all or most ailing IPPs in a country is likely to lead to rational and effective solutions, while a partial settlement may undercut the other IPPs.

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