Setting the pace

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Attracting foreign investment and, more specifically, project financing to global power markets requires addressing a common mix of issues concerning project cost and revenue risks. Solutions can vary, however, to accommodate resource and institutional differences among markets. Herein we use three markets ? Brazil, China, and Indonesia ? as examples that offer attractive supply/demand fundamentals but remain challenging for foreign investment and project finance.

Currently, Brazil faces significant impediments to attracting project finance in urgently needed thermal capacity, while China and Indonesia being relatively dormant despite strong underlying fundamentals, as each country is in process of changing its structural approach to securing power generation investment. The unique resource and institutional features of fundamentally strong but economically challenging investment environments beg for finding structural and market solutions. We review current impediments to securing investment and suggest several institutional and structural modifications to overcome financing hurdles.

Framework

While regulatory, market, contract, and investment protection frameworks differ between countries, overall political and macroeconomic stability represents perhaps the most important feature determining relative attractiveness to investors.

As a central component of effective national economic development, power sector infrastructure investment policies often closely reflect the country's political and economic stability; specifically, the country's ability to balance fiscal with sector investment and income distribution policies. The ability to attract investment capital is dependent on the country's ability to manage cost recovery across the power sector through effective tariff, tax collection, and/or cross-subsidy systems. These efforts are eased by an efficient, competitive and transparent market structure. In sum, the ability to affect a solution to the project financing challenge, based on a market model, relies on a predicate of:

? An effectively functioning market and contract framework.

? An objective and functional regulatory regime.

? A set of creditworthy counter-parties and enforceable performance obligations.

However, numerous institutional, technical and economic constraints present themselves in the course of transitioning to such markets. The combination of technical implementation challenges and political friction in the form of resistance to a rational, albeit initially painful, market rules has derailed many a well-conceived power sector investment plans.

Even with effective support from regulatory, market, contractual and investment frameworks, creative structures to deal with the key constraints will be needed to secure project financing. Notably, as discussed later after reviewing Brazil, China, and Indonesia market fundamentals, mechanisms to effectively address risk at both the macroeconomic and project-level, such as currency value exposure, contract and credit exposures will be critical to facilitating financing requirements.

Power Sector Fundamentals

Brazil

Current Crisis

Brazil currently is in the mist of a power shortage caused by the worst drought in 70 years and what The Wall Street Journal termed ?policy blunders of Amazonian proportions.? For several years in the midst of strong demand growth driven in part by low tariffs, Brazil failed to address in its restructuring program a number of issues blocking investment in new power plants, causing new thermal project development to lag behind requirements.

The immediate consequences of this shortage was the imposition of a temporary rationing program requiring consumption reductions of up to 20% generally and 25% for energy intensive industries, and the fast-tracking of a number of thermal power plants.

Installed Capacity

As shown in Exhibit 1, Brazil has an aggregate installed electric power generation capacity of approximately 66,000 MW. The generation sector is dominated by hydroelectric capacity. Approximately 92% of installed capacity is provided by hydroelectric facilities.

Region Hydroelectric Thermal Total

Capacity Capacity (MW)

(MW) (MW)

North 4,230 0 4,230

Northeast 13,965 58 14,023

South 7,893 2,332 10,225

Southeast/Midwest 34,290 3,275 37,565

Total 60,378 5,665 66,043

The North, Northeast, SE/MW, and South systems are presently interconnected with further transmission expansion planned, but there are significant transmission and capacity differences among the regions. The impact of power imports from other countries is small due to the relatively modest volume of imports and the cost of transmission.

Demand Growth

Pace Global forecasts average annual energy demand growth in Brazil of just over 4%, lower than forecast by Eletrobrás (the federal electricity company). Nevertheless, Pace Global projects nearly a 60% increase in demand by the year 2010 and a 100% increase by 2016.

The Brazilian market has experienced an annual capacity expansion rate of approximately 1,600 MW over the past 20 years. During the 2000-2016 period, planned additions must average approximately 3,300 MW per year, or 105% greater than previously experienced.

Eletrobrás' expansion forecast assumes that there will be unlimited financing to support power project development to meet load growth. Pace Global forecasts financing for power generation to average $3.3 billion between 2000 and 2009, in large part owing to institutional constraints. This means meeting Pace Global's power forecast requires that twice the historical level of financing of power generation projects in Brazil. This is an indication of the importance of addressing investment and specifically project finance requirements.

Market Restructuring

In recent years, Brazil has taken action to restructure its electricity sector, including initiatives aimed at increasing the role of private investment, eliminating barriers to foreign investment, and increasing competition, as follows:

? New concession and power industry legal frameworks, including permitting the formation of independent power producers.

? A constitutional amendment to remove nationality restrictions in the electric power industry.

? Privatizations, mainly involving distribution companies (only about 20% of Brazil's installed capacity has been sold).

Restructuring has resulting in the creation of an independent regulator (?ANEEL?), an independent system operator (?ONS?), a wholesale energy market (?MAE?), and a wholesale energy market operator (?ASMAE?).

ANEEL launched MAE in September 2000, but to date MAE has been a major disappointment, owing to inadequate market, legal and performance obligations, a retroactive price-setting mechanism, and a resulting lack of market liquidity. Under a transition program illustrated in Exhibit 2, distributors are obligated to purchase 100% of their power supply from generators until 2003. Thereafter, the reduction in long-term Power Purchase Agreements (?PPA?) volumes should lead to greater spot market trading and the development of a wholesale power market.

Thermal Plant Development

In an effort to rapidly increase thermal capacity, Brazil initiated a program that seeks to add 55 thermal generation facilities with a total capacity of over 17,000 MW by 2005. Thermal IPP development has lagged, however, with only a few of the planned thermal plants underway. To spur development and eliminate project risks associated with commodity price volatility, Brazil established a fixed gas price for emergency program plants. Even with this, thermal IPP development has lagged due to the power-pricing regime. While IPPs pay for fuel in US dollars, they must sell power in Brazilian reals. Furthermore, final prices to distributors are capped. This regulatory policy not only limits IPP margins to unacceptable levels, but also exposes them to substantial currency risk.

Failure to resolve the disparity in risk assessment of costs and revenues will continue to inhibit the foreign investment that is essential to the development of sufficient generation capacity to meet current and future power demand. The consequences are readily apparent, as critical industries, such as aluminum, mining, and chemicals, have already cited a lack of generation capacity as a constraint to future production growth. If generation capacity growth does not come about as needed, Brazil's current and future economic growth will be severely constrained.

China

Capacity and Generation

China's power system is the second largest in the world in installed capacity and generation. At the end of 1999, installed capacity was 299 GW. Prior to the 1997 Asian financial crisis, China had a shortage of generating capacity. Today, China has surplus capacity but that will not last long.

Overall, of total installed capacity thermal represents 75%, hydro 24%, nuclear 0.7%, and renewables 0.1%. Coal accounts for 99% of total thermal capacity, with less than 1% coming from oil.

The capacity mix differs in China's east and west regions. Generating capacity in the Northeast, East, and North is predominantly thermal. The proportion of hydropower increases to 20-30% in Central China, and further increases in the South and West. In particular, Sichuan and Yunnan have abundant developed and undeveloped hydroelectric resources. However, most of China's hydroelectric generating plants are run-of-river stations resulting in poor seasonal and regulation capability, creating risks of shortages in some regions during the high demand periods in dry years.

Between 1990 and 1997, power output in China grew at an average annual rate of just over 9%. With the 1997 Asian financial crisis, power output growth fell by half. However, power demand in 2000 was 10% higher than in 1999. Official forecasts show demand growth to average 5-6% through 2005, and the need for new capacity additions at an average annual rate of 3.1%. If demand grows at a rate greater than 6%, China may have reliability problems over the intermediate term.

In 2000, China added 19,000 MW of new capacity, bringing year-end installed capacity to 316 GW. Total power generation in 2000 reached l,350 TWh, a 9.5% increase from 1999. Both East China and Guangdong experienced record peak loads and double-digit electricity growth rates.

Power Grids and Integration Push

As shown in Exhibit 3, seven regional power grids plus five independent provincial power grids (Shandong, Fujian, Hainan, Xinjiang, and Tibet) comprise the power system in China.

China has a regional mismatch between power supply resources and major load centers. Large-scale hydroelectric generation is in the western part of the country while load centers are primarily on the east coast. The lack of system integration means that China is currently composed of a number of somewhat isolated regional power systems. Each regional system has unique characteristics, and most must rely on their own regional resources to maintain power supply reliability.

The national government has embarked upon an aggressive program ? the West China Development Strategy ? to develop new generating resources and large-scale transmission linking the power markets. Upon completion of these large-scale projects, China will have a broadly integrated power system with three larger regional power grids in the north, central, and south by 2010.

Market Restructuring

Concurrent with these development and integration initiatives, China is in the early stages of a major power system restructuring. The restructuring details remain under debate, with stark contrasts between those who point to Western failures such as California to support a ?natural monopoly and unique industry? approach and those who point to investment, efficiency, and environmental faults in China's past approaches in support of a ?market oriented and open investment? approach.

Consistent with the China's overall movement to privatized and market-oriented restructuring and in light of the investment requirements, Pace Global expects that China's power sector policies will provide for:

? Competitive generation supply.

? The divestiture of state owned generating assets.

? Provisions for both competitive spot markets and bilateral contracts.

? Rationalized tariff structures that are more consistent with western power markets.

Tariffs are regulated by central and local governments, but the complexity of price setting and an unclear division of government functions have hindered regulation. The producer tariff, also called the ?generation price? or ?on-grid price?, is cost-based. The long-term target of China's electric power tariff reform is to segregate generation from transmission and stimulate competitive bidding for on-grid supply contracts.

Generation prices from IPPs are based on the ?new plant-new price? policy and include fuel, labor, O&M, debt service payments, and depreciation. Under this policy, the so-called ?debt-repayment price? is supposed to provide sufficient revenues for the repayment of principal and interest within a relatively short period, usually 10 years.

In the medium term (5 to 10 years), tariffs will likely continue to be regulated on a cost basis. Generation and transmission assets will be segregated, and a cost-based transmission fee will be separated from the current bundled power tariff. We expect new regulations that will extend the debt amortization period of new power projects, as this could both significantly reduce the price of power and facilitate investment. Many fees and surcharges added by local governments may also be eliminated.

China also needs to make significant improvements in its dispatch system. Currently, lack of coordination between various levels of operation (e.g., the State Power Company, provincial, county, city) harms efficiency. This problem is particularly large in the four independent power networks in the south, particularly Guangdong, where IPPs account for more than 50% of the total installed capacity. A functional market will require a reliable set of dispatch rules. In addition, there is no established policy for calculating reserve margins or stated system reserve margin requirements. We believe that a minimum reserve margin requirement will need to be developed at the provincial level, and that a system to ensure adequate compensation for capacity value will need to parallel such rules.

Indonesia

Until the 1997 Asian monetary crisis, Indonesia was experiencing brisk economic and electricity demand growth, with 27 PPAs signed with IPPs. The financial crisis and a serious devaluation of the rupiah in 1997 slowed power demand growth and made it clear that PLN could not afford most of the PPAs. Work to renegotiate a select number of these PPAs is ongoing, but the situation and Indonesia's continuing political and economic crisis has damaged its status with developers and lenders.

The Java-Bali power system has just over 15,000 MW of formerly state-owned generating capacity and over 3,000 MW of IPP capacity in operation. Java-Bali's reserve margins are currently over 50 percent, but high levels are necessary to avoid transmission congestion moving power from east to west into the heavily populated Jakarta region. Over the longer term, with an expected 9% annual growth in demand, Java-Bali needs an additional 50,000 MW of capacity by 2020. Further, a significant portion of the required baseload additions may need to be coal-fired, which has longer lead times than other thermal technologies.

Exhibit 4 illustrates the timing of necessary capacity additions that will be needed to serve load growth and provide a reserve margins to maintain reasonable reliability, assuming that the east-west transmission system is completed by 2006. Market rules, a revised regulatory framework, and a mix of long-term and spot contract structures will be needed to accommodate generation investment, and a fiscally strong demonstrated cross-subsidies structure will be needed, as residential rates will have to be transparently cross-subsidized, but wholesale power prices will need to fully reflect costs in order to attract requistie generation capacity investment.

As of August 2001, Java-Bali appears to be moving toward an interim single-buyer market that holds promise of addressing the first step in transitioning to truly competitive market, backed by a legal, regulatory, and contractual framework that will have a long way to go inorder to again spur private investment and support project finance in Indonesia.

Financing Fundamentals

Given these fundamental supply/demand factors, it's worth a closer look at the challenges in project financing power projects in these and comparable markets.

The fundamental prerequisites for attracting project finance to the power infrastructure sectors can be grouped among macroeconomic, institutional and project-specific categories. Importantly, the macroeconomic and institutional prerequisites flow down to the project level, with specific guarantees required at the project level often required to secure financing.

Exhibit 5 details specific concerns in each category, and also provides a general, clearly subjective and only an indicative ranking of each of our representative markets on a national basis. Such rankings can be useful in developing an initial and highly relative sense of project finance risk, as well as potential mitigation strategies and costs. Such initial rankings, however, are necessarily subjective and general until project specifics; government and developer commitments to the project can be clarified. Each market and project presents a unique structuring challenge for a project to minimize macroeconomic, institutional and project-specific exposures.

Exhibit 5: Indicative Rankings by

Power Generation Financing Factors

1 = Strong 2 = Middling 3 = Weak

Ranking Factor Brazil China Indonesia

A. Macroeconomic

1. Stable fiscal policy, inflation controls 3 2 3

2. Stable tax & tariff structures 3 2 2

3. Stable currency & risk management 3 2 3

4. Local capital markets 2 2 3

5. Functional cross-subsidy mechanisms 3 2 3

6. Reliable credits and government guarantees 2 2 3

7. Limited & insurable political risk 1 2 3

B. Institutional

1. Rule of law, contract integrity, arbitration 1 2 3

2. Independent regulatory oversight 2 2 3

3. Defined market rules 2 2 3

4. Level playing field 3 3 3

5. Functional infrastructure ? grid & fuel supply 2 2 2

6. Property rights enforced 2 2 2

7. Transparent environmental & permitting 2 2 2

8. Favorable multi-lateral relations 2 2 3

C. Project-Specific

1. Reliable revenue streams 2 2 3

2. Controllable or pass-through costs 3 2 3

3. Functional mix of contract markets 2 3 3

4. Credit-worthy counter-parties 2 2 3

5. Reliable fuel supply & grid access 1 2 2

6. Insurance & risk mitigation instruments 2 2 3

7. Capable contractors & staff 1 1 2

8. Low cost of capital & LT debt 3 2 3

9. Flexible loan structures & security mechanisms 2 2 3

Country Initiatives and Challenges

Based on above rankings, it apparent there are significant challenges to securing project finance in each country. It is not surprising, therefore, that efforts have been initiated in all three countries to restructure and re-establish a power sector investment environment supportive of project finance.

Brazil is perhaps best positioned to make material progress in the short run, despite, or perhaps in part because of, the recent year's power capacity shortfall. In Brazil, currency risk and exposures to the wholesale vs. retail price squeeze are perhaps the most readily apparent hurdles to project finance. Short-term progress will occur if the market rules and fuel-to-power currency issue can be resolved, whether by market mechanisms or insurance products (as with the AES Tiete financing). Longer term, Brazil will need to accelerate the divestiture of state-owned generation and distribution assets, and establish around reliable market rules with an integrated mix of hydro and thermal generation pricing rules.

Significantly, Brazil is in process of reviewing its entire regulatory and market framework, towards a goal of elucidating a revised energy policy.

In China, while a shortfall of generation capacity is not an immediate concern under normal weather, the government is seeking to move forward with the separation of generation from transmission, a revised regulatory framework, and prepare for privitization. We anticipate mid-term progress in securing additional generation capacity, particularly within the addition of large hydro assets in the Northwest region and thermal projects in the east coast regional markets. The eastern and northern markets will serve as models for the application of restructured and competitive power markets, most likely with both a long-term bilateral and spot market. Shandong Province has the distinction of being the most progressive of China's regional markets, and has achieved the highest level of foreign investment and IPP activity in the country. The successful development of market-based models in China's progressive provinces should help to overcome much of the policy risk associated with current development efforts based on term contract structures and relatively low return thresholds.

Indonesia must first demonstrate its ability to successfully address restructured IPP contracts. Indonesia also must demonstrate a commitment to a transitional market structures, including a workable single buyer market model, which will then transition to a multi-buyer market as Indonesia addresses its restructuring plan and associated new regulatory framework. This transitional restructuring activity will need to precede the divestiture of government-owned generation assets. Importantly, the movement to a multi-buyer market should dovetail with the completion of Indonesia's southern transmission loop, which will effectively integrate the entire transmission grid, hopefully by 2006. Indonesia's sectoral reforms will also require the un-bundling of distribution companies, as well as the establishment of a subsidy fund and credit facility to financially support distribution companies should then follow divestiture in generation.

Solutions

Company strategies

As all national power sector factors cannot be expected to score a financable ranking, investment and project structuring needs to mitigate macroeconomic and institutional risks. Strategies by which developers and other investors have sought to mitigate higher-level risk concerns include:

1. Value-chain integration ? combining upstream and downstream power asset positions to reduce risk within a single stage (e.g., tying generation to distribution, and fuel to power, etc.);

2. Technology, fuel and regional diversification in generation ? limiting reliance on a single generation asset of sub-regional performance, thereby creating a portfolio value profile;

3. Strategic asset investments ? tying power generation capacity to value-added manufacturing investments;

4. Minority and performance participation ? limiting investments to minority shares in liquid assets and tying return to specific performance metrics (e.g., efficiency factors).

In our case study markets, notably Brazil, China and Indonesia, efforts to develop generation assets by affecting the strategies above have met with only partial success.

Common Project Risks

There are several financing challenges common to most developing and restructuring power sectors where public and private dialogue can yield fertile ground for merging institutional and market solutions. Examples include the management of:

? Currency risk.

? Capacity value and cost recovery.

? Customer credit-worthiness.

Currency risk is a common problem when power is sold in local currency, and costs are incurred in another currency. Unless power prices are allowed to automatically adjust to reflect currency devaluation, the owner of a power generation asset paying hard currency costs is exposed to reduced margins to the extent the erosion in local currency values is not hedged.

On the other hand, allowing currency devaluation costs to be passed through would penalize those assets that had been financed largely with local currency, as their competitive advantage would be eroded in a market that granted automatic price recovery.

A potential solution may be at times to force developers to seek out currency devaluation insurance through several means:

1. Hedging exchange rate risk in local currency markets, while simultaneously moving the government to support increased liquidity in foreign exchange markets by creating incentives for longer-term trading.

2. Offer price discounts to customers (e.g., large end-users with export earnings) willing to purchase power in foreign denominations. This would motivate companies best positioned to hedge this risk to use their ability to manage the currency risk as a method of leveraging a lower or more stable price of power. This initiative could also be supported by government incentive or insurance programs.

3. Create an exchange risk insurance pool. Here, policies could be offered for various terms and rates as a function of the price premium paid, and levels of coverage provided. This would effectively institutionalize a menu of insurance products not dissimilar to the OPIC currency ?collar? insurance vehicle created for the Tietê project, with automatic extension and ?roll? provisions to ensure the longest possible forward cover.

4. Create a currency reserve account in project loans in order to trap and extend currency devaluation coverage as a function the project realizing super pro forma returns.

5. Encourage fuel suppliers and marketers to toll merchant thermal plants in manner that fixes the spread between dollar-based fuel prices and local currency-based power prices, so that the exchange rate risk is transferred to the generator toller or owner.

Capacity value recovery is a critical element in ensuring that capital will be directed to an emerging power sector, particularly one characterized by relatively immature markets or a mix of generation resources that could potentially displace or be favored relatively to an externally financed IPP project. This issue has a number of dimensions, including the issue of reserve value (i.e., for peakers and intermediate facilities), thermal vs. hydro assets, and private vs. existing state-owned assets.

Capacity value can be extracted by designated capacity payments, for example as embedded in a long-term PPA, or by opportunistic recovery in a competitive power market. Under uncertain market conditions, the latter form of recovery may be highly uncertain and, therefore, insufficient to support project finance. Solutions may include the following, as a function of market and potential asset loan structures:

1. Provide a guaranteed capacity payment, sufficient to provide minimum debt service coverage, but utilizing a capacity reserve fund, to be filled when realized revenues exceed marginal costs, such that the capacity guarantee payment is funded from the market to the extent possible. Insure such a program via the embedded hedge on capacity values contained in existing, government-owned generation assets, whose capacity revenue windfalls would be applied to making the guaranteed payments when prices are strong, and consumers would pay a capacity surcharge when prices are weak (i.e., not extracted from the market).

2. Encourage long-term bilateral contracts and require load serving entities (LSEs) to maintain a reserve margin within their supply portfolio, with such margin recognizing option (premium) payments to existing generators under term contract for the right to call on additional generation capacity in the future to maintain the LSE's future reserve margin obligations.

3. Structure revenue allocations among hydro and thermal generators in a manner that levelizes the capacity value among the units, so that baseload, albeit variable (as a function of flow rates) hydro units are in effect making a capacity contribution to thermal units as a function of their relative availability factors, divided by the total value of capacity payments among hydro and thermal generators in a given pricing sub-region.

4. Require generators to extract capacity value from the market, but permit such value extraction as a function of a capital cost recovery factor calculated over a reasonable number of years (e.g., 3-4) to allow for variance in the water flows, temperatures, etc.

In these approaches to the capacity payment challenge, an appropriate mix of thermal (peaking) and baseload hydro or thermal capacity can be encouraged via a combination of government fiat and loan structures that trap capacity value and allocate it over time and across generation assets.

Credit Support is also a critical prerequisite to project finance. In marginal economies and restructuring power sectors this is often a problem, as it is even in a robust merchant market with investment grade entities exposed to sudden market or regulatory exposures. Governments seeking to restructure their power sectors, and particularly those moving towards a market model, must take measures to support the viability of the LSEs purchasing power, and the suppliers of that power. Methods of ensuring creditworthiness may include:

1. Creating a government-backed ?clearinghouse? function with suppliers and LSEs, but requiring each qualified participant to maintain pre-specified financial reporting and management standards in order to ensure the viability of the clearinghouse.

2. Establish a government-supported credit agencyto provide performance guarantees for a fee, with such fee levels determined under standard credit and ratings procedures, but also reflecting government policy and the embedded offset value of government-owned generation assets.

3. Evolve towards a private credit clearing structure under one or both models above, and supplement with the development of direct credit agreements with anchor customers, including industrial and institutional customers willing to provide credit support to an LSE in exchange for price or supply concessions.

The key is that private initiative must be supported, and on occasion initially enabled by government ? sponsored credit and market support mechanisms. This is particularly relevant at the distribution company or LSE level, as their financial solvency is often dependent on their ability to collect tariffs, which in turn depends on the government's policy for providing transparent cross-subsidies and affordable power to the residential and institutional sectors in particular.

Lacking a combination of private risk mitigation and government controls, efforts to evolve to a market-based power sector will be fraught with payment delays, disputes and ultimately market failure. With such mechanisms, supported by government institutional and fiscal measures to ensure financial liquidity and to support the requisite cash flow needs of sector enterprises, a finance-able project framework, tied to an appropriately structured loan agreement can more readily find support from lenders and developers.