The Political Economy of the Brazilian Power Industry Reform

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About the Author

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About the Political Economy of Power Market Reform Study

Early in 2002, the Program initiated a study to compare the experiences with power market restructuring in five critical developing countries—Brazil, China, India, Mexico and South Africa. Each individual country study examines the interaction of the political, legal, and economic forces that affect how countries restructure their electricity systems away from state domination and towards greater use of markets.

This paper presents results from one of the countries studied. For other individual country studies, synthesis of results, and in-country events on electricity markets, please see the Program website at http://pesd.stanford.edu.

Political Economy of the Brazilian Power Industry Reform

Adilson de Oliveira[1]

"Les richesses s´accumulent en haut,
les risques en bas."
Ulrick Beck[2]

1. Introduction

After a long period of rapid growth the Brazilian power industry entered a period of stagnation and crisis in the 1980s. Ever since the 1930s a series of tariff rules and nationalizations had squeezed private investors from the market. In their place, state enterprises had assumed the function of distributing electricity in Brazil's 26 states; Eletrobras, owned by the central government, managed the transmission system and also generated much of the electricity in Brazil. Through its control over state funds for building power plants, Eletrobras pursued vast projects such as the Itaipu hydroelectric plant and assured low electricity prices as part of the government's policy of import substitution. In the shock of the two oil crises and the Latin American debt crisis this system unraveled. Financing costs escalated yet tariffs were kept low; losses mounted.

The process of reforming the electric power system began after the new democratic government took power in 1990. But a more radical effort at reform arose only in the middle 1990s in response to two main pressures. One was the goal of reorienting the entire economy away from the import substitution policies protection to a more competitive system that promised greater investment and economic growth (Diniz, 2002). As a first step the finance ministry induced several states to sell valuable electric assets to private investors and plug gaping holes in their balance sheets. Privatization of these jewel assets

[1] I am grateful to Peter Greiner for his comments on an earlier version of this paper and to David Victor for his careful review.
[2] A German scholar commenting on the tendency for modern societies to create large risky systems that benefit a narrow few while shifting the diffuse consequences of systemic risk to society (Beck, 2001).

was made politically attractive to the states when coupled with loans that allowed their governments to finance projects that generated jobs and other political benefits. The finance authorities were singular in their goal of raising the maximum amount of hard currency and did not have any strategy for the industry after privatization. Indeed, ad-hoc regulations were adopted to inflate the value of the assets at the time of privatization; the rules were settled in a different way once private investors had committed to the market.

The second pressure for reform came from international trends in the electric power sector—in particular, the model of reform adopted in England and Wales (e.g., Surrey, 1996). International experts crafted all the major elements of the "standard model" of reform—continued privatization, open access to the grid, and competition in generation and in retailing—into a strategy tailored for Brazil. That strategy envisioned that private investors would assume key roles as owners and operators of the power system, under the control of an independent regulator. The role of government was to be limited only to empowering the regulator and to providing strategic policy guidance.

In practice, restructuring has been much more difficult to implement than implied in the standard model. The privatization-for-cash approach to reform generated early income for the government but did not resolve key problems in making the power business a profitable and reliable enterprise. Through much of this period the architects of reform focused on profitability and investment; a drought in 2001, however, underscored the need also to focus on reliability.

Brazil's hydroelectric system—which supplies 95% of the country's power when rains are flush—is run by a system operator embedded in a culture of integrated centralized management. Dispatch rules give priority to hydro over thermal power and aim never to spill water "over the dam"--multiple dams are operated as a single system even though the owners vary. An interlocking revenue-sharing mechanism makes dam ownership more like a guaranteed bond asset than separate, competitive enterprises. The principal risk in the system—that of under-supply during extreme drought, such as in 2001—is shifted to the customer. A wholesale pool gives the appearance of competition, but in fact prices are artificial and generated by computer models.

This chapter explores the origins of the Brazilian power system and its transformation from a system that had been initiated by private foreign investors in the late 19^{th} century to one controlled completely by state-owned enterprises (section II). It then examines the mounting forces that generated pressure for reform and how the broader political and economic changes in Brazil shaped the reform process (section III). The most dramatic reforms were initiated by financial authorities who were interested in achieving macroeconomic goals. Interests that opposed reform—especially in the states, which feared losing politically valuable assets—sought to delay and redirect the reform process. At the same time, a large group of technicians in the power companies as well as a cadre of consultants with experience in power sector reform elsewhere in the world pursued clashing visions for reform. The result was a hybrid power market that combined "reformed" elements—in which private owners compete for tenders and operate in an environment where many prices are artificially generated by computer—along with state-owned and centrally-managed enterprises.

In section IV we explore the consequences of this system and give particular attention to the problem of attracting investment into thermal power sources—notably natural gas. The political compromise that created Brazil's hybrid system was attractive to most of the powerful players who were present at the negotiations. Integrated and risk-dispersing control of the hydro system allowed incumbent generators to continue with their operations largely unaffected and with virtually assured profits; foreign investors found these generators to be low-risk opportunities, and the treasury welcomed the resources from the privatizations. In a few states the government refused to dispose of distribution assets and the system, today, remains largely a state-dominated system. The hybrid system that has emerged gives little voice to interests who were not well represented—that is, potential new generators who could burn newly available gas resources. A few such plants have been built, but the only such plants that have proved profitable are those that have attracted special government subsidies or special gas contracts with Petrobras, the state-owned oil and gas company; dispatch rules and other provisions make it difficult for potential private investors in most gas-fired plants to justify the expenditure.

So far the reform has produced a system that is remarkably similar to the old system—a few names on doors have changed and there has been a net flow of resources into the treasury from privatizations. Assessing the effect of the reforms so far is difficult. It appears that the main benefits of reform have emerged not from full-blown competition—which does not exist in Brazil—but, rather, in creating a structure that produces much greater transparency about the economic and technical conditions of the power supply, as well as the costs and the dispatch rules that govern the system. Although the fundamental problem of creating incentives to invest in new power supply (other than hydroelectric plants) remains unsolved, in this new system the independent regulator—when allowed to exercise its authority—is much better able than its predecessors to exert control over the system for the benefit of consumers.

2. Historical Development of the Industry

Brazil is physically large (8.5 million Km^2) with 170 million in-habitants that live concentrated in large cities along the Atlantic coastline (table 1). The Brazilian federal system shares power between states (each with its own elected governor) and the center.

Table 1 – Key Demographic and Economic Statistics

	1950	1960	1970	1980	1991	2000
Total Population (millions)	51.9	70.1	93.1	121.61	149.9	170.1
Urban Population (millions)	16.3	28.5	47.5	72.1	98.5	123.5
Number of Cities	1,887	2,764	3,952	3,991	4,491	5,507
GDP (1980 = 100)	11.8	24.0	43.7	100.0	118.1	151.8
GDP/capita (US$)	899	1,359	1,861	3,260	3,124	3,538
Power Consumption (GWh)	8,513	18,346	37,673	115,874	225,372	331,596

Source: IBGE, Eletrobras and IPEA

At the federal level, power is divided between the Executive—led by the President, who names thousands of political appointees to key administrative positions—and the Congress. The exact allocation of responsibility has shifted with the myriad of constitutional reforms undertaken over the last century, and formal powers of elected officials have been suspended in periods when the military has ruled. In practice, nearly all key decisions lie with the Executive—usually in the President's office—because powers in Congress are usually diffuse and difficult to craft into working coalitions.

As in most other countries, the earliest investors in Brazil's power industry were private companies that built exclusive concessions in large cities and for large industries—mainly in the industrialized and wealthier southeast of the country. A Canadian Group (Light) obtained the concessions for Rio and São Paulo in 1897; in 1927 a U.S. firm (AMFORP) obtained concessions for several other large towns. The main source of generation—then and now—was falling water. Brazilian fossil fuels reserves are relatively scarce;[3] water resources are plentiful, except in the Northeast, and total about 260 GW of potential supply. The topography in the industrialized South-East is favorable for the construction of large reservoirs[4], a situation that substantially improves the economics of hydropower plants[5]. Without any single federal process for awarding public concession of power services, each municipality established its own rules. Typically, investors operated within contracts that fixed maximum tariffs (reviewed monthly) and payments half in domestic currency and half in gold standard (*Cláusula Ouro*). Under this framework, the power industry installed capacity grew at 7.6% a year between 1900 and 1930. As shown in figure 1 (left panel) private investors dominated the industry.

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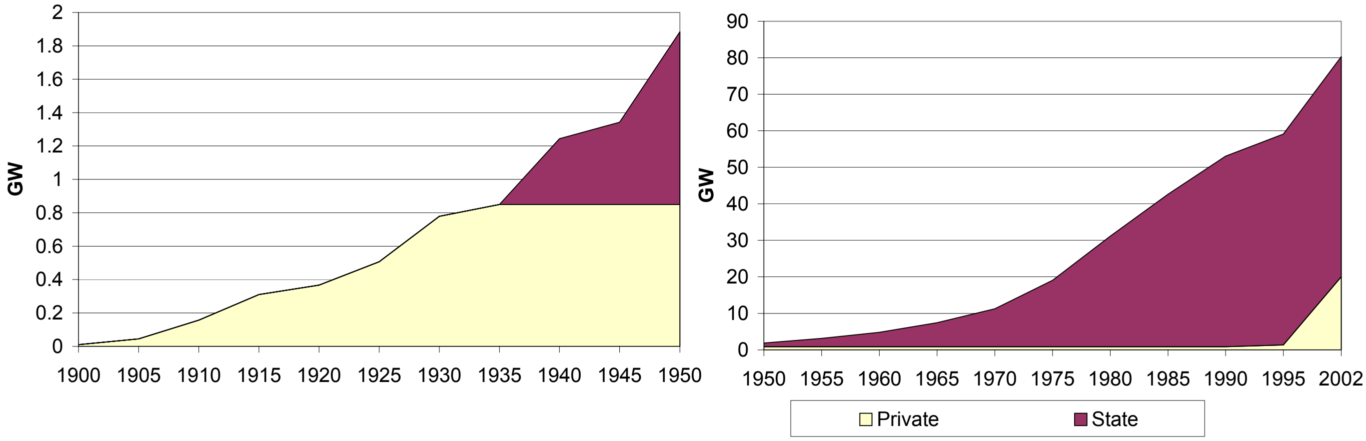
[3] Coal reserves are in the extreme South (Rio Grande do Sul and Santa Catarina) but they are of poor quality. Until the 1980´s, oil and natural gas reserves were small but they grew substantially in the 1980´s, after large oil field discoveries off Rio de Janeiro. However, the country still is importing both fuels.

[4] Existing reservoirs are able to store up to 130 TWh, almost half a year of current consumption.

[5] The water flow can be streamlined during the year, increasing the capacity factor of the power plants.

Figure 1 – Installed Capacity by Ownership

1900-50 on the Left and 1950-2002 on the Right. Note the Scale Change



Sources: IBGE and Aneel

The 1929 New York Stock Exchange crash had a profound impact in the Brazilian economy. Coffee exports, the single tradable Brazilian product in those years, dropped dramatically, pushing the economy into deep recession (Furtado, 1972). Growing urban middle class dissatisfaction with the political control exerted by the *coroneis* (landlords) culminated an uprising that installed a revolutionary government with strong nationalist policies (Stepan, 1973). The new federal government eclipsed some of the powers of the 26 states. Successive Brazilian governments structured a fast growing but protected industrial sector. From the very start, the role of foreign companies in energy supply was a political issue. Nationalists argued that energy was a strategic factor of production and could not be left to foreign control; liberals responded that foreign investors would bring technology and capital, both scarcely available in the country. As in Mexico (see Carreon and Jiminez, this volume), the nationalists eventually won the conflict (Medeiros Lima, 1975).

The Virtuous Circle

In 1934, the federal government laid the cornerstone for development of a hydroelectric power by adopting the Water Code, which assigned to the federal government the property rights of the hydropower potential of Brazilian rivers and the authority to regulate the power services. A National Council for Water and Power (CNAEE)[6] was created to regulate the industry, and the federal government introduced a cost of service (cost plus) tariff scheme. Inspired by nationalism, the government also adopted rules that discouraged foreign investors—notably, it calculated costs in nominal terms (Dias Leite, 1997), and the Water Code forced investors to absorb currency risks by abolishing the *Clausula Ouro*,.

The new tariff regime—along with other factors such as continued world depression and the war in Europe—caused private power companies to curtail investment, and growth in generating capacity slowed (figure 1). Yet demand for power continued to soar due to industrialization, urbanization and economic growth—with the predictable result that rationing of electricity was required in several cities, creating a serious problem for the emerging industrial sector. Public pressure urged a larger role of government in the power industry; federal and state governments invested in power projects with the goal of reducing the gap between supply and potential demand. Starting in 1945 (and extending to the 1970s) the federal government's investments formed four regional electricity suppliers—Chesf (1945), Furnas (1947), Eletrosul (1968) and Eletronorte (1972)[7].

Although democracy was reinstated at the end of World War II, the industrialization strategy did not change. With private investors interested in the energy sector increasingly wary of Brazil, a consensus emerged between nationalists and liberals that state owned companies should control the energy sector. Petrobras, a federal government monopoly, was created in 1954 to develop the incipient oil market. In 1962 the federal government created Eletrobras as a holding company for the four federally-owned regional suppliers plus other electricity assets owned by the federal government.[8] Eletrobras also assumed the role of imposing compatible technical standards and coordinating development of the power system into a truly national

[6] Later, National Department for Water and Power (DNAEE) and, since 1996, National Power Agency (Aneel).

[7] State governments created CEEE (1943), in Rio Grande do Sul; CEMIG (1952) in Minas Gerais; Copel (1954), in Paraná; Uselpa and Cherp, in São Paulo.

[8] Besides the nuclear power plants and the Brazilian share of Itaipu, Eletrobras had the control of the four regional generation and transmission companies (Eletronorte, Eletrosul, Furnas and CHESF), and owns minority shares in every other power company.

interconnected grid.[9] Both of these state-owned enterprises operated with the mandate to spread the supply of modern energy sources, at prices that would aid industrialization (de Oliveira, 1977).

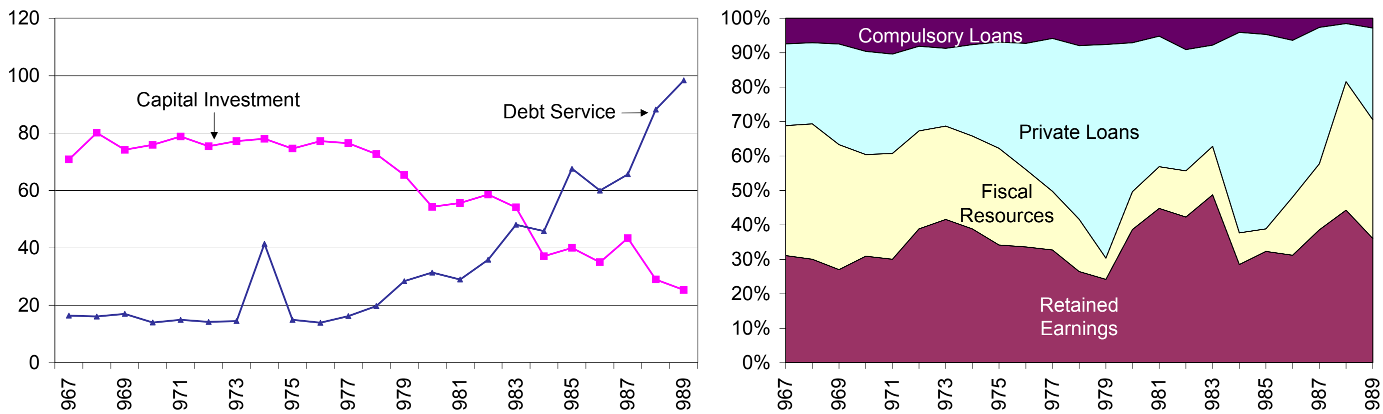
Initially, hydropower projects were built with no coordination among the power companies. In the 1960s, when different companies were envisaging the construction of power plants on the same river runs the federal government, with the financial support of the World Bank, engaged a consortium of international engineering companies (Canambra[10]) to craft a long-term coordinated development plan for the South and the South-East power systems. Using a fuel oil thermal power plant as a benchmark, Canambra concluded that thermal power plants would be more costly than tapping the available hydropower sites and thus advised that thermal power plants should be limited to play a complementary role[11] in the power industry. The oil shocks reinforced this conclusion—they made hydropower plants even more competitive and reinforced the growing perception among power policy makers that Brazil was a hydropower country.

The bulk of the conventional thermal power capacity is installed in South, close to coal mines, but thermal power plants (burning oil products) also supply power to several isolated power markets, mainly in the Amazonian region. A nuclear power program launched at the end of the 1960´s, never blossomed as it was constantly constrained by the unattractive economics of nuclear technology. However, the support of the military and the Brazilian scientific community (in favor of peaceful use of nuclear power) led to the construction of two nuclear power plants (600 MW and 1250 MW) in a single site (Angra dos Reis/Rio de Janeiro). A third power plant (1250 MW) has been under construction since the 1980´s[12] at the same site but still has not guaranteed the financing for its completion.

[9] Until then, each power company decided on its technical standard, a situation that turned out very difficult during the interconnection of the regional power systems of the country.
[10] Montreal and Crippen, Canadian companies, plus Gibbs and Hill, an American company.
[11] Thermal power plants should be dispatched in periods of reduced rain fall.
[12] The 600 MW power plant is a turn key project bought from Westinghouse. The other two are the result of a comprehensive nuclear agreement between the Brazilian and the German governments that envisaged the construction of at least 8 nuclear power plants and the development of the nuclear fuel cycle in

To help finance the creation of a national power industry, in the 1950s Congress created a federal tax on power consumption (Imposto Único sobre Energia Elétrica – IUEE) and channeled the revenue into a National Electrification Fund—much as China today uses special national taxes to fund large power projects (see Zhang, this volume).[13] A few years later, industrial consumers were also ordered to supply compulsory loans for power projects, which became a small but not insignificant source of funding (figure 2). Funding for power projects was designed to come from a tripartite system: one-third from taxes and "parafiscal" levies, such as the IUEE and the compulsory loans;[14] one-third from retained earnings; and one-third from loans, such as from multilateral development banks and other sources. Most of these resources flowed through Eletrobras, which administered them according to its investment plan.

Figure 2 - Financial Situation of Brazilian Power Companies (1967-1989)
Resource Application on the Left and Financial Sources on the Right.
The series are calculated by the sum of balance sheets values of the Eletrobras Group.
Other Capital expenses are not available



Source: Electrobras

Brazil. Although the Brazilian-German agreement was not formally rejected, it is a consensus that it will end as soon as Angra III is put in operation.

[13] Revenues were shared between central government (40%) and state governments (60%).

[14] There is no easy translation of "parafiscal" resources into English. It includes the compulsory loans that were technically loans—in that when given they were expected to be paid back—but the state control over these financial flows meant that they were much less costly than market rate loans. In the1990´s, the compulsory loan mechanism is being phased out as part of an effort to make taxes more transparent.

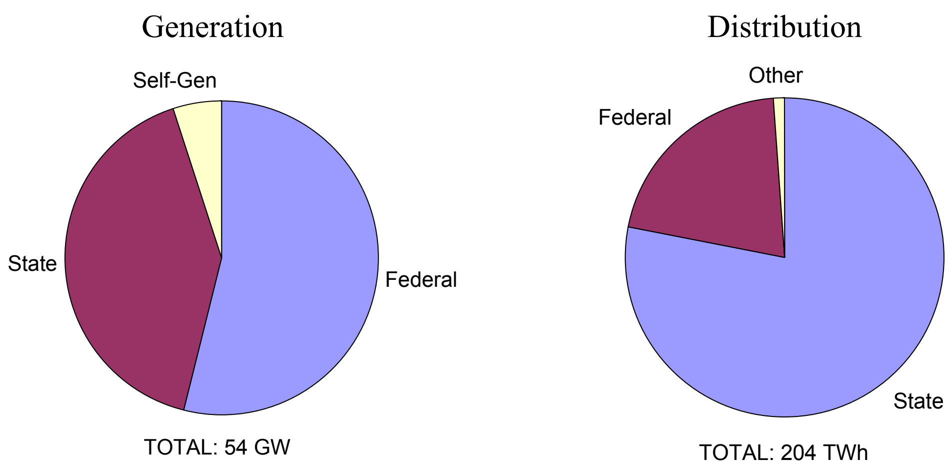
Easy access to low cost financial resources made possible for state enterprises to expand generating capacity at 8.8 % per year between 1945 and 1970—shown in figure 1—the public sector gradually supplanted private investors who saw tariffs not keep pace with inflation and were wary of unsecured currency risks.

In the early 1960s a fierce political battle between leftwing (mainly socialist) and rightwing (supported by the military) parties ended with the military removing civilians from government (Skidmore, 1969). The new regime, although radically right wing, did not change the industrialization and energy strategies of the past (Gaspari, 2002). Indeed, it deepened the federal government's control over generation and transmission by creating two coordinating committees—one for operating the interconnected grids (GCOI) and the other for planning generation and transmission expansions (GCPS)—both headed by Eletrobras. The aim of these committees was to induce all power companies to work together to explore economies of scale and scope (lower reserve margin, lower peak demand) offered by the interconnection of the regional grids. The logic was similar to that adopted all four of the other countries examined in detail in this book—competition was seen as wasteful, and monopoly (under government control) the best means to extend benefits of electrification to the society. At the time the technology of electric generation and transmission also favored integration and monopoly control—indeed, costs did decline with scale and scope and productivity rose with greater and lower cost electric service (de Oliveira, 1992).

Two regulatory innovations were introduced to guarantee that there was no financial risk for power projects. Non depreciated assets could be annually reevaluated in line with inflation, and power companies were allowed a tracking account (Conta de Resultados a Compensar – CRC) in their balance sheet if their tariffs were unable to provide their legal rate of return (between 10% and 12%) on non depreciated assets. The amount in this account should be recovered in future tariff increases[15].

[15] These new financial arrangements were intended to enhance the credit conditions of the power companies. They benefited both private and state-owned power companies but the movement for state control of the power industry was already unstoppable.

Figure 3 - Ownership of Generation (left) and Distribution (Right) Assets - 1988



Source: Electrobras

Even as the federal government centralized generation and transmission, the task of distribution was decentralized into the hands of the states (figure 3)—a reflection of the shared power in the Brazilian federal system. The federal government had acquired a few key distributors (AMFORP in 1965 and Light in 1977) and sold some of these assets back to the states, with loans from the state-controlled National Bank for Development (BNDES). Where private incumbents did not already exist, states created new power companies. The central government's aim was to create a federally controlled enterprise that generated and transmitted power to state-owned regional distribution companies. (A similar model was already in place in England and Wales and was adopted in other countries such as the State Electricity Boards in India [see Tongia, this volume].) Eletrobras occupied the central role in this strategy: its share of total investments in the power sector investments rose from 32.6% in 1974 to 60.7% in 1983 (Memória da Eletricidade, 1995). The federal government, eventually dominated the power business through Eletrobras control of low-cost financing and the requirements of a coordinated, interconnected national grid. Unable to tap these resources, state companies gradually reduced their presence in the generation and transmission of electricity.

Conflicts Emerge

The federal government strategy suited the large majority of the Brazilian states but was not gladly received by the states that already had their own vibrant generation and transmission companies (Camozzato, 1995). The conflict of interests between Eletrobras and the state power companies became especially intense in the 1970´s, as result of two federal government decisions: the construction of Itaipu and the introduction of a single tariff system.

In 1973, despite the strong opposition of the Argentinian government, Paraguay and Brazil signed a treaty to construct a binational power plant (Itaipu)[16]. Jointly managed by both countries but entirely financed by Brazil, the Itaipu power output (12,600 MW) is shared in equal parts between the two countries. Itaipu´s tariff is based on its production cost (nearly entirely the amortization of capital expenditure) and is fixed in American dollars. Because demand in Paraguay is insufficient to absorb its 50% share, Eletrobras committed to buy any Paraguayan surplus[17]. In order to accommodate the Itaipu output in the Brazilian market, a law passed in Congress that granted dispatching priority for Itaipu into the Brazilian market, forcing the state companies of the South and the South-East to reduce their power plants´ generation and to postpone their projects. (Similarly, in China large state-controlled projects have led the central government to mandate states to take the power [see Zhang, this volume].)

In 1977, the government sought to reduce regional economic disparities by introducing a single tariff regime for the whole country. Even as the South and Southeastern parts of the country became wealthy and highly urbanized, the vast majority of Brazil's poor were dispersed in the North and Northeast with little access to modern opportunities, including electric power service.[18] A compensation mechanism forced low cost, profitable companies of the South-East to transfer revenues to a fund (Reserva Geral de Garantia - RGG) controlled by Eletrobras and

[16] Argentina's opposition was geopolitical and technical. Politically, they feared Paraguay (traditionally a close Argentine ally) would become more closely integrated with Brazil—in fact, that political outcome has occurred. Technically, Argentina raised many objections—among them, the fear of downstream risk to Argentina from catastrophic failure of the dam and from water fluctuations. Some changes were adopted to address these technical objections, but the principal fear was geopolitical.

[17] At present, about 95% of Itaipu's output is sold in Brazil.

[18] Today, almost three quarters of the population is living in urban areas as compared to only 31.3% in 1950. Of the 170 million Brazilians, 50 million still live below the poverty line—the largest share in the North and in the Northeast of the country.

used to compensate high costs companies of the North and the North-East of Brazil. Through this mechanism, Brazilians in different regions and cities faced the same tariff structure—even though the cost to serve low-intensity and dispersed power users in the northeast was much higher than in the dense industrialized cities of the southeast. The military assured that both measures were accepted (if angrily) by the South-East generation companies.

The financial effect of these measures was disastrous. Low and high cost companies alike saw no reason to control costs, which inflated rapidly. Tariffs should have risen in tandem since the basic tariff regime was based on costs. Formally, tariffs were regulated by the National Water and Electrical Power Department (DNAEE), but in practice the finance ministry set prices. Concerned about inflation, the finance ministry refused to allow tariffs to increase accordingly to costs. The *unreceived* revenue was placed in the CRC account for recovery in future tariff increases—allowing the power companies to show their guaranteed 10% rate of return in their balance sheets even as their cash flow dwindled. But this trick, which pushed actual recovery of costs into the future, did not fix the fundamental problem. Facing a sharply rising need for investment, the power companies (through Eletrobras and the government) sought loans overseas to supply the balance that lenders were happy to oblige as they saw utilities with supposedly guaranteed revenue streams as good risk. They all assumed that these loans were, in essence, backed by the state. In 1980, only 20% of the industry's financial resources went to service debt, a fraction that rose steadily (and peaked at 98.4% in 1989)[19].

[19] This shift occurred despite the greater availability of special funds that could be tapped for construction, like the Global Reserve for Reversion ("RGR") fund to which each company is required to pay annually 3% of the value its fixed assets. The nominal purpose of this fund was to handle the growing buyback obligations under the Water Law concession scheme, although in practice it became just another one of the "parafiscal" revenue resources. Typically, concessions were for 35 years after which time they reverted to the federal government, which was then obliged to compensate the owner (usually a private investor or state government) for the value of its non depreciated assets. The fund still exists in Eletrobras' accounts and is used mainly to finance rural electrification projects.

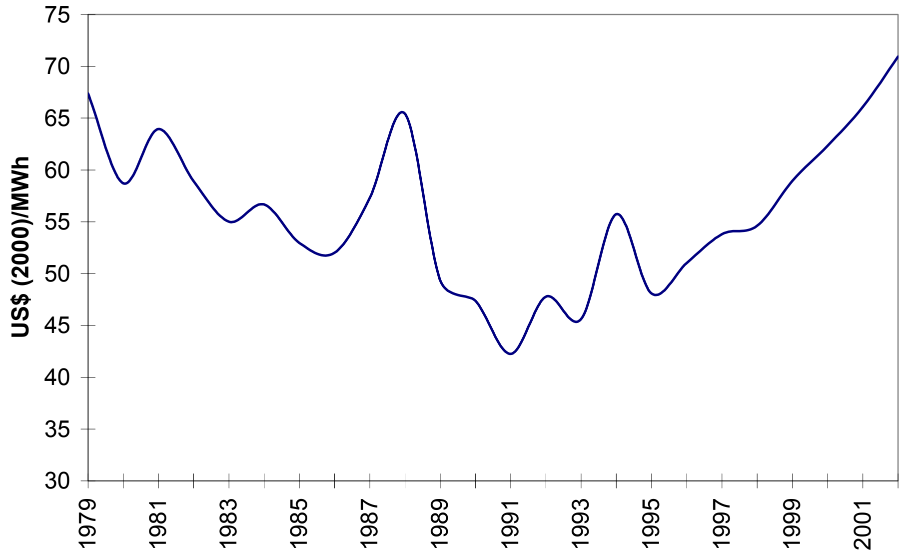
The Vicious Circle

At the beginning of the 1970´s, the Brazilian economy was growing rapidly (10% a year) but 80% of oil consumption was imported. When the first oil price spike deteriorated the country´s external accounts, the military government launched an ambitious industrialization program intended to accelerate the process of import substitution (Castro and Souza, 1985). The assumption was that, in due time, investments in Brazilian industry would alleviate the need for imports; the surplus in the trade balance would then pay for the external loans that had financed these projects. However, this treadmill stopped short of maturity in the wake of the second oil shock and the Latin-American debt crisis. The increase in the prime rate in the United States forced the devaluation of the Brazilian currency, inducing a spiral of inflation and fiscal deficit that disordered the macroeconomic fundamentals of the country (Carneiro and Modiano, 1990). Government policies forced the Brazilian economy into a severe economic recession to avoid the country default.

In the context of economic recession, power consumption fell well below the forecasts of the early 1970´s, which increased average costs as capital-intensive generators sat idle. Yet the Ministry of Finance, more worried about the rest of the economy, mandated tariffs below the rate of inflation (figure 4).[20] Power companies´ net cash flow declined even as higher interest rates raised their financial obligations. The "three thirds" financial strategy for the power industry collapsed. Lacking funding (figure 5), several power projects had to be delayed, but no state power company was prepared to postpone its favorite projects voluntarily. Eletrobras found it difficult to play its central coordinating role as it was under a constant shadow of accusation that it protected its own power projects—notably Itaipu—to the detriment of the state companies of the South-East projects (Medeiros, 1993).

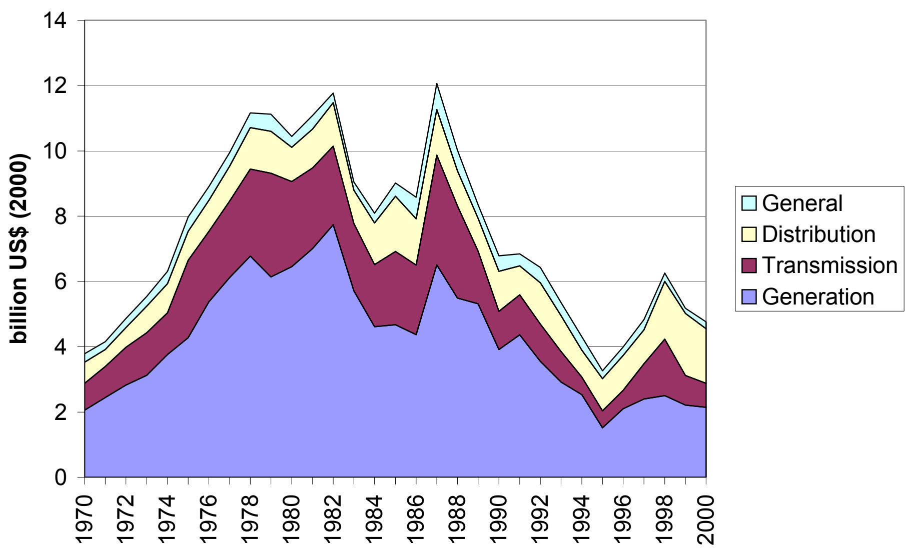
[20] Legally, DNAEE was responsible for fixing power tariffs but in practice the regulator had to submit its pricing policy to the Ministry of Finances.

Figure 4 - Average Prices Paid by Final Consumers - US$(2000)/MWh



Sources: Eletrobras, Aneel and Ipea

Figure 5 - Investment in Brazilian Power Supply Industry – US$ (2000) billion



Sources: Eletrobras, Ipea and Pinhel (2000)

The state (provincial) power companies found a creative, although ultimately disastrous, strategy for their cash flow problem. Arguing that they were suffering the consequences of tariffs that the federal government had fixed below costs, the state of São Paulo power companies decided to withhold payments for the power supply of federal companies. Several other state companies followed the São Paulo strategy, with the result that power system accounts became a shell game with accumulated obligations parked in special accounts (CRC) that were rolled over and financed only because the federal government had complete control of the industry. No power project under construction was officially cancelled because of lack of funding; rather, nearly all were slowed with no economic or financial rationality in the decision—outright cancellation of these projects, which provided visible jobs and achievements coveted by politicians, would have been politically too costly. The case of the Porto Primavera hydropower plant in Sao Paulo is particularly emblematic: from conception to the first power delivery took 18 years!

In 1987, this serious situation prompted the Ministry of Mines and Energy (MME), with the support of the World Bank, to organize a working group—the Institutional Revision of the Power Sector ("REVISE" in the Portuguese abbreviation)—to assess causes and remedies to the looming power crisis (Eletrobras, 1988). Among the problems they identified, three were particularly critical. First, politically-appointed managers of the state-owned companies performed poorly and were not accountable to consumers. Moreover, managers had done little to protect environmental quality as they built ever-larger hydro projects. Second, the keystone coordinating role of Eletrobras was under fire—neither the state power companies nor Eletrobras' own regional subsidiaries accepted its role. Third, tariffs had been set to achieve economic, social and regional policies objectives but overlooking the crucial need of power companies´ financial viability.[21] Remarkably, the REVISE report had not addressed the looming problem of a funding shortfall for capital projects, despite the fact that several power projects were lacking funds needed to sustain their construction schedule.

Participation in REVISE was dominated by government and the power companies. These stakeholders thought that the system was working well, with only a few fixes required at the margins—notably, they sought approval for higher tariffs and looked to government for larger

[21] The World Bank pointed out that because tariffs were kept artificially low, state owned power companies had to increase their loans, adding inflationary pressure to the economy (World Bank, 1992).

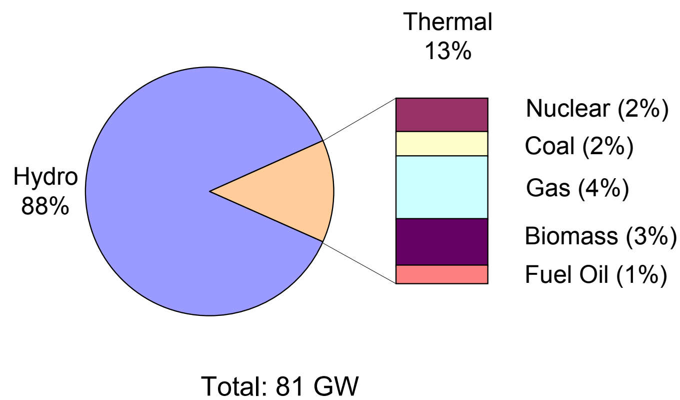
funding allocations for investment in new projects. Just as the REVISE report was finalized Brazil went through a tumultuous period of political change and the recommendations were left sitting on the shelf.

3. Restructuring the Electric Power System

In the midst of the Latin American debt crisis, the military rulers stepped aside in 1985. Congress appointed a transition government, which led to a new constitution (1988) and Presidential elections (1989). Despite its fragile political support, the new government imposed an aggressive but disastrous macroeconomic shock therapy. To improve the fiscal situation, deposits in banking account and savings were frozen for 18 months. But contrary to plan, inflation spiraled out of control and president Collor was impeached when evidence surfaced of widespread corruption in his government. Vice-president Itamar Franco took power and launched an innovative macroeconomic stabilization plan in 1994, coupled to a series of other liberal reforms (Pinheiro, Giambiagi and Gostkorzewicz, 1999). Import duties were reduced; the National Privatization Program, launched by Collor, was accelerated. Improved confidence as well as the seeds of a liberal economy helped to reduce inflation from 47% a month in the beginning of 1994 to 35% a year within a few months. After several years of mediocre GDP growth, the economy gained momentum; GDP grew 4.5% in 1994.

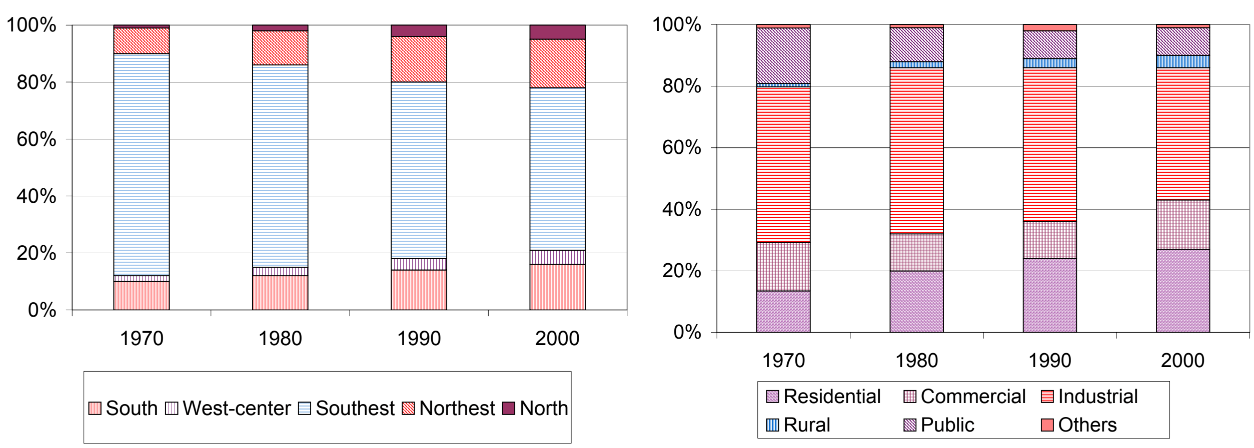
As these larger political forces swept across the Brazilian government, the power sector reform (figures 6, 7 and 8) came to the forefront of the political agenda. Three distinct efforts at reform in the electric power sector could be distinguished—each with quite different motivations. Together, these three attempts have yielded a hybrid market that is remarkably similar to the system that existed before reformers attempted to work their magic on the electric power sector.

Figure 6 – Installed Capacity, 2003



Source: Aneel.

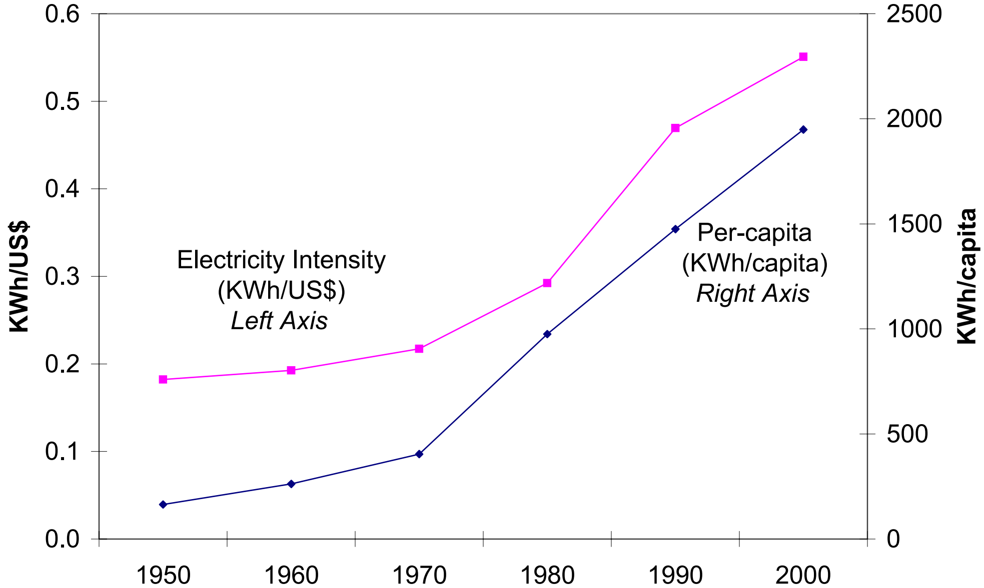
Figure 7 – Electricity Consumption by Regions (Left) and by Consumer Group (Right)



TOTAL: 1970 – 36 TWh 1980 – 114 TWh 1990 – 201 TWh 2000

Source: Eletrobras

Figure 8 – Electricity Consumption per Capita and per Unit of GDP



Source: IBGE

Marginal Reforms

The initial stimulus to reform the power industry came from the political reforms embodied in the 1988 constitution. As part of the effort to make taxes on industry more transparent and to delink taxes from specific uses, these reforms included abrogation of the tax on power formerly destined to finance the power companies (IUEE). The new constitution also required that public service concessions, including electricity, be licensed through public auctions in an effort to make the industry more responsive to market forces. Collor's Secretary for Energy, a respected official from the World Bank, favored approaches that were consistent with the standard model for power market restructuring, but he found strong opposition to his ideas. Embattled and distracted by scandal, Collor devoted few political resources to the large privatization program he had initiated. By the time he and his successor Franco left office the tidal wave of privatization had not yet reached electricity assets.

In 1993, the government created SINTREL (the National Power Transmission System) with a requirement for open access to the grid—in the hope that privately-financed independent power producers (IPPs) would eventually arrive in the market. The government also passed a law declaring that power companies no longer had a legally guaranteed return for their investments;[22] rather, the cost plus tariff regime was replaced by a regime in which prices would be reviewed regularly.[23] Power tariffs were almost doubled, to an average of US$ 62/ MWh; the national tariff equalization mechanism was abolished, and the federal government agreed to pay to the state power companies approximately $26 billion in CRC credits that had accumulated on their balance sheets. The net effect of these measures was to remove some of the financial distortions in the power system and to make the state companies into financially viable enterprises—at least so long as tariffs remained in line with costs. But like REVISE before it, these reforms did nothing to the fundamental structure of the industry nor to the incentives that affected most plant operators. The change in rules readjusted the role of the federal treasury in sustaining the industry by eliminating the CRC system and several special fees, but these changes were marginal—they offered no viable strategy for sustaining (private) investment.

Reform through Privatization

In 1995, restructuring of the power sector gained momentum around the mission of privatization. Taking advantage of its landslide victory in the election, president Cardoso was able to muster the 2/3 majority needed for constitutional amendments that would make

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[22] The regime that would be used to review tariffs was never established. Nevertheless, there is a constitutional article that guarantees to any public concession the right to *economic-financial equilibrium of the concession*. It is not clear the exact meaning of this concept; the judiciary tends to admit that companies operating under concession have the right to a fair rate of return, although it is unclear how much this rate of return must be.

[23] These prices would be regularly reviewed by DNAEE to take care of inflation.

it much easier to liberalize and privatize the energy industry. Those amendments removed the Petrobras legal monopoly on the hydrocarbons market and eliminated the rule that had restricted ownership of hydropower plants to Brazilians. (Since the 1930s, the Brazilian Constitution had noted that electricity was a public service; however, unlike in Mexico, the Brazilian Constitution never required that the state own all electric power assets [see Carreon and Jiminez, this volume].)

In the wake of these Constitutional reforms Congress passed a 1995 Law that voided all hydropower concessions made after 1988 as well as concessions granted before 1988 whose construction was not yet under way. Hydropower concessions that had lagged behind their construction schedule—as many had during the industries perpetual financial difficulties since the late 1970s—were forced to show DNAEE that they could raise funds and complete construction, or lose the concession. Altogether, DNAAE recovered 33 hydropower concessions—a rich portfolio of projects ready for sale to private investors. To make these assets even more attractive the government also adopted new institutions and rules—such as for IPPs—that reflected standard international practice. Government also encouraged state power companies to organize consortia with private investors to finish construction on concessions that were behind schedule.

The National Bank for Development (BNDES) occupied the central role in the privatization process, having sold steel mills, hotels, port facilities and sundry other state owned assets since the wave of privatization began in the early 1990s[24]. In the power sector the BNDES strategy was, first, to privatize distribution companies; generation would follow and, finally, transmission assets would be sold. First on the block were the distributors that, by accident of history, had become part of Eletrobras: Espirito Santo's Escelsa and Rio's Light.[25]

[24] BNDES was created in the 1950s to finance long-term development projects, especially those related to infrastructure. Special levies on Brazilian salaries are channeled into BNDES, which also raises money in the international financial market.

[25] When AMFORP was nationalised, (1965) the Espirito Santo distribution company remained within Eletrobras. In 1977 the concession for Light—the distributor that served part of the Rio market and part

BNDES did not have a strategy for reform of the sector as a whole. It sought reform only insofar as privatization would provide fresh financial resources for the Treasury. For that matter, BNDES was looking for a reform that could elevate the price of the power sector assets. To estimate the market price of Escelsa, the first to be auctioned, BNDES established a provisional tariff regime and required the auction winner to sign a concession contract granting that the future regulator could redesign the tariff regime. Unsurprisingly, no international investor accepted these terms. However, a consortium of Brazilian private investors assembled a package that included distressed government debt that they used at face value (but had purchased at a steep discount on secondary markets) and won the auction with a bid that offered an 11.8% premium over the minimum price.

A tariff regime with much lower regulatory risk would be needed to attract more investors and higher prices. In the midst of privatizing Light, second on the auction block, BNDES adopted a price cap regime modeled on the system for regulating electricity distributors in England and Wales. Non-controllable costs (e.g., wholesale electricity prices and taxes) would be passed directly to consumers; other costs (e.g. services and personnel) would be indexed to inflation, minus a factor X that reflected the expected rise in productivity each year. Investors would be allowed a fair rate of return plus any surplus they could earn above the "X" expected improvement in performance. Tariffs would be reviewed each year; the tariff baseline (along with the "X" factor) would be revised every five years, and the operator could request a special review if unusual circumstances prevented it from earning a fair return. The key to this whole system was the regulator; potential investors did not trust DNAEE, which was seen as a ward of industry insiders who did the government's bidding. Congress passed a law establishing in late 1996 a new independent regulator—Aneel (Agência Nacional de Energia Elétrica)—to replace DNAEE. At roughly the same time, independent regulators were established for many other parts of the liberalizing economy, such as telecommunications. Although formally

of São Paulo—was about to expire and the assets were bought back by the federal government. São Paulo bought the portion that served its market, but the Rio portion was assigned to Eletrobras as well.

under the umbrella of the Ministry of Mines and Energy (MME), Aneel is financially and administratively independent from the government and funded by charges levied on generators and distributors (plus any fines it collects from companies that don't comply with quality-of-service standards). A board of five directors is appointed by the federal governments (and confirmed by Congress) for four year terms. Aneel has been assigned not just the task of regulating tariffs but also the licensing and controlling of power concessions; these multiple roles may yield conflicts of interest in the future. As regulator, Aneel must serve as impartial arbiter of disputes between the power companies and the government; however, as steward of concessions, Aneel also serves as the government´s representative in the disputes.[26]

True to form, BNDES fixed the initial tariffs for Light to generate the highest market value—the fair rate of return was set at 10%, and X was fixed at zero for the first seven years. (Zero was an implausibly modest value for X—at the time, most analysts thought that Light offered abundant opportunity for lifting productivity through improved collections and streamlining the workforce). After an intense negotiation, a consortium, controlled by international investors (EDF, AES and Houston Power) paid the minimum price for a controlling share in Light, with a large fraction of their payment (70%) in hard currency of particular value to a government that was seeking to shore up its balance sheet.

The unions might have scuttled these two privatizations, but a BNDES-engineered compensation package blunted their opposition. BNDES offered a minority share for Escelsa and Light employees at a discount on the minimum price. Moreover, in both cases generous packages were offered for employees who left the company—in many cases through early retirement.

The next step was to sell distributors that were owned by the state governments. Governors and local politicians feared loss of the political patronage that accompanies power systems and opposed the move initially. However, state governors were facing large

[26] To solve this problem, a bill was sent to Congress at the end of 2003 that removes from the regulator the licensing power and gives it back to government.

financial difficulties due to radical change in their fiscal situation following the Real stabilization plan. BNDES bailed out these strapped states by offering soft loans in exchange for these governments' acquiescence to the privatizations. The loans would be repaid with the proceeds from the privatizations, and each state could keep any extra revenues that remained.

The states of Bahia (Coelba) and of Rio de Janeiro (CERJ), whose governors were politically close to the federal government, accepted the BNDES deal. At the end of 1996, a consortium headed by Iberdrola (Spain) bought Coelba while CERJ controlling stocks were sold to a consortium headed by Chilectra (Chile). Both sales earned a premium (77.3% and 30% over their minimum prices respectively).

The encouraging experience of these two states led several other state governors to see the BNDES upfront loan as an opportunity to acquire a financial windfall before the 1998 election. Changes in the constitution reversed a rule that had barred most officials from seeking re-election; politicians already in office were eager to raise funds and launch projects before voters went to the polls. The decision by São Paulo, the state with the largest power load in Brazil, to vertically disintegrate its power company and privatize its distributors and generators was widely seen as a signal that the BNDES strategy would be successful. Yet the rapid privatization by BNDES had alarmed incumbents in the industry who felt that the BNDES privatization would harm their interests; they articulated those fears, along with power sector experts, by underscoring that electricity was a unique industry of national importance and the lack of a coherent strategy could harm the nation—no matter how much BNDES extracted in revenue from its privatization.

Power Experts Come In

BNDES viewed the existing stakeholders—in particular, Ministry of Mines and Energy (MME) and Eletrobras—with suspicion and did not seek their advice during the privatization process. However, these interests were able to insert themselves into the privatization process by enlisting a consortium of outside consultants led by Coopers and Lybrand to prepare a comprehensive proposal for the reform of the industry. As detailed by Paixão (2000), this process marked the onset of the battle between BNDES (which sought rapid privatization) and the incumbent state-owned power companies (that wanted to protect their generation and transmission assets). MME acted as the interface between these two groups, with a slightly different objective: to ensure that needed investment in the power system would keep pace with demand during the rocky transition to a new organizational and financial model. The outcome of this process satisfied nearly all these core interests—BNDES, the incumbents, and MME—while not actually having much impact on the organization of the industry.

In contrast to the in-house process at BNDES, the MME consultation was highly participatory—at least within the industry, where all of Brazil's 60 power companies were represented. Thematic working groups presented their proposals in plenary sessions attended by 400 experts. Two issues dominated the discussion: the role of Eletrobras in coordinating funding within a privatized market, and decentralization of control over dispatch of generators and control of the transmission network.

BNDES argued that a privatized power industry allowed no role for Eletrobras as coordinator of funding mechanisms. (Extreme liberals within BNDES sought to shut down Eletrobras once its subsidiaries were privatized.) MME, however, argued that a central funding agent still would be needed for large hydropower projects and strategic transmission lines. Eletrobras offered its historical record of leveraging international funding for such projects as evidence that it was both competent and needed. BNDES, which had not funded any power projects since the creation of Eletrobras in the 1960s, decided to finance large power projects once again to demonstrate that Eletrobras was not an irreplaceable keystone for the Brazilian power system.

Decentralization was more complicated. BNDES and MME alike sought the separation of transmission services from generators; both also sought to break the four large regional generation companies of Eletrobras into smaller enterprises. But the motivation for these views was quite different. BNDES sought the maximum price at the privatization auctions, where smaller firms would be more digestible and attractive to outside investors. MME was mindful of the need to improve efficiency in the power system, but it was more worried that investors would not build new hydropower plants unless a mechanism existed to reduce the hydrological risk of such ventures.

The state companies and the regional subsidiaries of Eletrobras strongly opposed these concepts, arguing that vertical integration was needed to assure the efficient operation of a cooperative hydropower system. Generators along a single cascade required coordination of water flows; moreover, coordination, they argued, would lead to a more reliable power supply as the risks of drought could be spread across the many different basins in the hydro system. The operator of the hydro plants ("GCOI" in its Portuguese acronym) estimated that "uncoordinated dispatch"—that is, market competition—would cause a loss of 30% of generating capacity due to spilled water and other operational inefficiencies (Santos, 1996). Of the state generators, only São Paulo—where the government aggressively sought the higher efficiency and lower power costs promised by privatization and competition—favored vertical separation and market competition for its power companies.

Conceiving a "Hybrid Market"

As debate over the many drafts of the MME plan droned on, the Real stabilization plan was in urgent need of more hard currency. BNDES pressured the MME to accelerate the reform process so that privatization of generators could continue and in early 1998 the government created the key institutions for the new system: the National System Operator (ONS), a not-for-profit civil association of power companies that would dispatch plants and operate the transmission system,[27] and the Wholesale Power Market (Paixão, 2000). ONS is guided by a

[27] The government (MME) plans expansion of the transmission system, and Aneel offers new lines for competitive tender.

Board of Directors that includes representatives of each electric stakeholder group (generation, transmission, distributors, and "free" consumers[28]).

The key to understanding this system lies in the rules that ONS deploys when dispatching power stations, a process that is guided by computer models that aim to optimize for "least cost" operation. These same models also compute four regional spot prices (South, Southeast/Centre-West, Northeast and North) as indicators of the relative value of power at each node.[29] As operator of the system—not the long-term strategic planner—the ONS models focus on short-run marginal costs. Since hydro plants have nearly no operating costs whereas the operating costs at thermal plants are typically high, the system yields very low prices and minimizes the use of fossil fuels. This approach also corresponds with the hydropower engineering culture that dominates the ONS board—by this logic, the goal is to coordinate water flowing through cascades of turbines minimizing the water that spills past the turbines. Thermal plants, which reside outside this culture, are envisioned as backup facilities to be used only in periods of drought. This approach implies that thermal power plants will remain idle for long periods of time, which is inconsistent with the purchase power agreements (PPAs) demanded by the financiers. To avoid this problem, these power plants were allowed to declare their power capacity as "inflexible" (i.e., must run).

To reduce the commercial risk to hydropower investors—a key aim of MME and BNDES—the concept of "assured energy" was introduced. Using historical rainfall data, Aneel estimates the total amount of electricity that the set of existing hydropower plants can generate in the worst historical hydrological period[30]. This total amount, called the *assured energy* of the hydropower system, is divided among the hydropower plants[31] and each hydropower plant receives from Aneel a certificate of its assured energy. Although in wet years hydropower plants will produce much more than their assured energy, they can **only** sell their assured energy, The

[28] Consumers that have peak load exceeding 3 MW are free to shop around for their power supply, if they want; the remaining consumers (called captive) are served by their local distribution companies.
[29] Aneel decided to reduce the sub-markets to two from the beginning of 2003: South/Southeast/Centre-West and North/Northeast.
[30] This amount is estimated assuming 5% risk that the hydropower system will be unable to actually produce it.
[31] Essentially, based on the capacity factor of the hydropower plants.

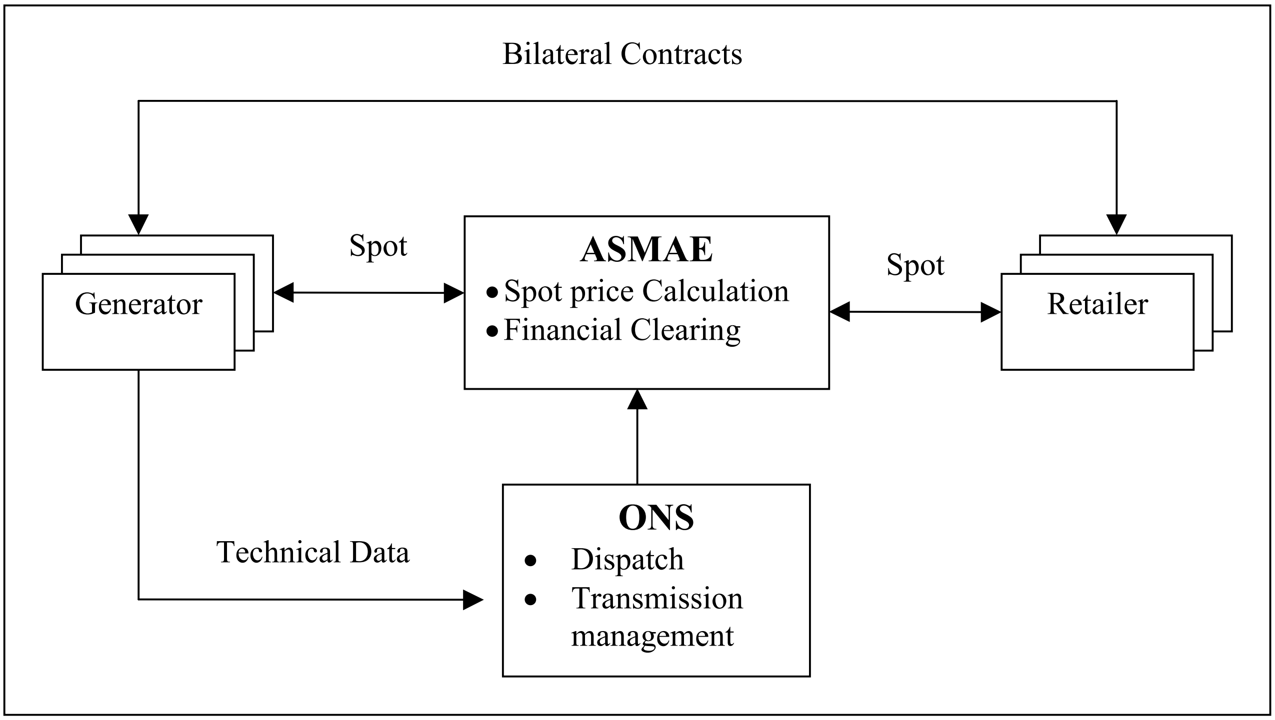
additional power, produced in wet years, called "secondary energy," is sold in the spot market—when water is abundant that market is flush and prices, obviously, are much lower than the contract price for the assured energy.

To guarantee each hydropower plant its assured energy in spite of the water actually flowing through its turbines, a financial mechanism (Power Reallocation Mechanism–MRE) was created for sharing the hydrological risk among hydropower plants. Whenever water flows are unfavorable for a particular plant, ONS dispatches another hydropower plant to assure that every plant "delivers" at least the assured energy listed on its Aneel concession.

This mechanism of socializing risk and revenue flows across the entire hydro system pleased BNDES. It transformed investment in a hydro plant from a risky venture that depended on variable rainfall and the actions of possibly uncoordinated releases of water by upriver plants into a low-risk instrument, akin to a bond, that yielded a predictable stream of revenues. The mechanism pleased Eletrobras and the power companies because it augmented the economic competitiveness of their hydropower plants, and it pleased the MME because the same dispatch and revenue-sharing rules would apply to hydropower plants that were yet to be constructed, which would improve their economic competitiveness against hypothetical future thermal power plants. Traditional suppliers of hydropower projects also loved the move. Only investors contemplating thermal projects could oppose this move, but they were not yet on the stage.

Figure 9 - Market Organization, 2000

Power contracts are bilaterally settled but must be reported to ASMAE, where the power transactions not covered by contracts (spot trade) are cleared. Power flows in the interconnected grid are monitored by the ONS and informed to ASMAE.



Financial transactions are cleared in a wholesale power market (MAE) that is functionally separate from the system operator and shown on figure 9.[32] Generators are free to sign bilateral contracts with distributors and with "free" consumers (large power users whose peak demand exceeds 3 MW), and power is also traded on a "spot" market. Real market prices emerge from the bilateral contracts, but the spot market is a fiction—its prices are generated by the same set of models utilized by ONS to dispatch generators and manage the transmission system. The models compute the opportunity cost of the water flow with data from the hydropower plants (availability, water flow, reservoir level, operational cost) and thermal power plants (inflexibility, availability, operational cost).

[32] An executive committee (Coex) with fourteen (14) members indicated by the Assembly was originally responsible for managing MAE with the support of an administration company (ASMAE).

Power plants are dispatched by merit order and the spot price is fixed by the last unit dispatched. Using projections for future demand and the most likely water flow, the spot price is currently calculated for a period of 30 days but the aim is to have an hourly price.

Another "hybrid" aspect of this new market was a long transition process from the old "cost plus" plants to a new system based on opportunity cost. During a nine year transitional period the existing power plants had initial contracts with distribution companies at the 1996 prices, indexed to inflation.[33] From 2003, one-quarter of the power in these initial contracts would be released each year for sale in the market at bilaterally negotiated prices. This transitional rule was considered necessary because the 1996 price of old power was roughly half the estimated long-term cost of new power supply (US$40/MWh, based on gas-fired capacity as the most attractive and available hydro sites had been tapped already). Had power been priced at the real opportunity cost then tariffs would have increased sharply, an intolerable outcome to the inflation-minded government. During this transition period the new plants were free to negotiate in the open market—an impossible situation for new investors contemplating gas-fired plants.

Under this hybrid market system, distribution companies knew that in most years a very large surplus of hydropower secondary energy would be available in the spot market. The government feared that the distribution companies would seize this opportunity only to find themselves exposed to extremely high spot prices in dry years. Thus Aneel mandated that the distributors secure 85% (later 95%) of their power demand as firm bilateral contracts. Aneel also applied price caps to the power purchased by distribution companies—with perverse effects that we discuss later. The net effect of all these rules has been to reinforce the role of the spot market as a computer-generated phenomenon rather

[33] The equivalent to US$ 22/MWh, in the South and the Southeast, and US$ 16/MWh, in the North and the Northeast, at that time. Itaipu has its price fixed in dollars, at much higher level (US$ 34).

than a true market, with prices largely the result of administration rather than competition.[34]

4. Unresolved Issues: Fuel Diversity and Systemic Risk

By the metrics that mattered to the key players, the restructuring process moved rapidly and was largely successful. By 1998, sixteen distribution companies, with a total annual service of 160 TWh, had been sold, along with 9.2 GW of capacity in four generation companies (table 2). CEMIG, the vertically integrated company of the state of Minas Gerais, was partially privatized, having sold a 30% share of its voting capital to investors. Copel, the vertically integrated power company of Parana state, and Furnas, one of the four Eletrobras generation companies were both being prepared for privatization. Licenses for new power hydropower plants and transmission lines were sold in public auctions by Aneel at premium prices, and several private investors asked for Aneel authorization to build thermal power plants.[35] The average annual capacity additions rose from a low of 1.080 Gw per year in the early 1990s to 2.800 GW per year from 1995 to 2000. The flow of funds to the power industry, one of the main objectives of the reform, was back.

[34] The market is affected by many other regulations that we do not discuss here. For example, to avoid problems of market power there are limits on the share that any investor group can hold in the Brazilian power market. (20% of the national market; 25% of the Southern or Southeast/Centerwest markets, or 35% in any other regional market.) Vertical integration is also restricted—distribution companies are allowed to supply up to 30% of their market through self-dealing with their own power plants.

[35] Thermal power plants are not concessions; however, they require Aneel licenses to operate.

Table 2 – Brazilian Power Industry Privatization

Distribution C	**Market GWh 1998**	**AUCTION DAY**	**Price US$ millions**	**US$ / MWh**
Escelsa (F)	6,194	7/11/95	519	83.79
Light (F)	23,759	5/21/96	2,217	93.31
Cerj	7,208	11/20/96	587	81.44
Coelba	8,373	7/31/97	1,598	190.85
CEEE (N/NE)	5,213	10/21/97	1,486	285.06
CEEE (CO)	6,353	10/21/97	1,372	215.96
CPFL	19,045	11/05/97	2,731	143.40
Enersul	2,453	11/19/97	565	230.33
Cemat	2,718	11/27/97	353	129.87
Energipe	1,851	12/03/97	520	280.93
Cosern	2,590	12/12/97	606	233.98
Coelce	5,396	4/02/98	868	160.86
Metropolitana	35,578	4/15/98	1,777	49.95
Celpa	3,215	7/08/98	388	120.68
Elektro	6,407	7/16/98	1,273	198.69
Bandeirante	23,500	9/17/98	860	36.60
Celpe	7,018	18/02/00	1,004	143.06
Cemar	2,349	15/06/00	523	222.65
Saelpa	1,929	30/11/00	185	95.90
Total Distribution	171,149		19,432	113.54
GENERATION CO.	**CAPACITY (MW)**	**AUCTION DAY**	**Price US$ millions**	**Thousand US$ / KW**
Cachoeira Dourada	658	5/09/97	714	1085.11
Gerasul (F)	3,719	9/15/98	880	236.62
Paranapanema	2,148	7/28/99	682	317.50
Tiête	2,651	10/27/99	472	178.05
Total Generation	9,176		2,748	299.48
Total			**22,180**	

F- federal companies
Source: BNDES

Moreover, the newly privatized companies demonstrated better economic performance. A key measure of productivity—the number of employees per customer—was improving; most privatized distributors also decreased the number and duration of power outages.[36] The share of consumers with access to power was also improving—to about 95%. Crucially, the cost per MW of new hydropower installed capacity declined sharply due to improved control of construction and financial costs. (Thermal plants remained costly and hypothetical—we discuss that further below.) These improvements were evident not only in privatized firms but also in those enterprises still owned by the state and in the midst of preparation for privatization. Reform, it seemed, was delivering the envisaged results.

Nevertheless, one fundamental problem remained: in the zeal to privatize (and thus restructure) the system, no entity had assumed the task of long-term planning and policy guidance for the system as a whole. In the past, Eletrobras had played that role through its control of investment decisions, with MME providing additional support at the margins. In the restructured system, however, Eletrobras was in the midst of being broken apart, and its strategic planning functions eroded; MME was unable to fill the space; Aneel's mandate required that it serve as neutral arbiter rather than strategic planner; BNDES remained obsessed with the mission of extracting the maximum price for privatized assets, not steward of the power system. These problems were manifest in two tightly interlocking problems—one was the difficulty of attracting investment in new (gas-fired) thermal power stations, and the other the drought of 2001, which underscored the collective risk inherent in a hydropower system organized as in Brazil. The drought has focused minds on the problem and on stopgap solutions (increased investment in thermal generation), but actual solutions are not yet on the horizon.

[36] Aneel (2003)

Fossil Fuel Markets

Historically there was little connection between the fossil fuel markets and the Brazilian power system. Eletrobras developed the power system assuming that hydropower resources (which were constitutionally owned by the state) were plenty and that fossil fuels were scarce; Petrobras operated the oil market assuming that hydrocarbons were premium fuels that would not be used for generating electricity. Unsurprisingly, conventional thermal plants occupied only a small share of the Brazilian power installed capacity and an even smaller share of actual power generated (figure 6).

Until the 1990s there were few thermal power plants connected to the grid, mainly in the south around the low-quality coal mines. These plants were dispatched when reservoirs ran low, and their owners were allowed tariffs that compensated for their cost of building the generating capacity that sat idle during wet years. The cost of the fuel for thermal generation was diffused to the society as a whole through a compensation mechanism (the fuel cost account, or "CCC"). All consumers paid into the CCC fund according to the grid operator (the GCOI, controlled by Eletrobras) estimated need for thermal power dispatch over the year.

That situation was expected to change as large amounts of natural gas became available. In the early 1990s the Brazilian government committed to purchase 30 million m^3/day of gas from Bolivia as part of a political deal (brokered in part with US pressure) that would bind Bolivia more tightly to Brazil while also offering a substantial source of revenue to Bolivia. This aspect was particularly relevant because it facilitated the US fight to reduce trade in illicit drugs. The government instructed Petrobras to assemble a coalition to build a pipeline; not surprisingly, Petrobras found that no investor would participate without a firm take-or-pay clause built into the deal. At the same time, major oil finds offshore Rio had also generated large quantities of domestic associated gas. Saddled with all this gas Petrobras and the government scrambled to find markets. Mindful of its take-or-pay commitments to Bolivia and the wall of domestic gas on the horizon, the government adopted a broad policy goal of increasing the share of gas in Brazilian primary energy supply from less than 3% in the 1990s to 12% by 2010. The widespread use of combined cycle power plants elsewhere in the world—notably in Argentina, Chile and the U.K.—had convinced government that the massive new gas supplies would find a proper user in power generation.

The scheme for internalizing and diffusing the cost of thermal electric power generators had worked when the industry was integrated and the role of thermal electric generation was small. But 17 GW of thermal capacity mainly fuelled with natural gas, operating in a competitive electricity market, as the government envisioned for 2005, would be a different matter. The rude awakening for the government came when Petrobras offered thermal power plants the take-or-pay conditions of its contract for gas imports from Bolivia. Since their power would be more expensive than that from hydropower generators in relatively wet years, thermal power plants would not be dispatched in most years. With fuel in take-or-pay contracts, gas generators would have no choice but to declare themselves "inflexible" (must run) and thus were required to contract all of their power with buyers (distributors and "free" consumers). Moreover, Aneel had capped the prices for wholesale contracts that distributors would be allowed to pass to consumers. Any generator who fired with a long-term gas contract was in a box, squeezed between the cap on electricity price fixed by Aneel and the natural gas price fixed by Petrobras in its take-or-pay contract, and unable to make money.

For the potential generators of gas-fired electricity, the Brazilian market appeared to be a hydro cartel that was being perpetuated by the regulatory system. Moreover, gas users complained that gas from Petrobras was not competitive because the company was a monopoly[37] that attempted to pass the cost of the uneconomic Bolivian pipeline[38] to its customers. Gas supply was priced in dollars and indexed to international fuel prices, but electricity prices were regulated by Aneel in Brazilian currency—a risk that the sharp

[37] Petrobras, for the time being, is the single supplier of natural gas in the country. The few trunk pipelines that exist are regulated by the National Oil Agency (ANP), but prices for gas are a government decision.
[38] The pipeline was made costly as result of the political decision to extend it to Southern Brazil despite the fact that gas demand would be low in that region and exports from Argentina were already envisaged.

devaluation in 1999 made transparent to all. In this context, few investors actually built gas projects in Brazil

In late 1999 ONS warned that Brazilian reservoirs were at dangerous levels, and the government adopted special subsidies to attract rapid construction of gas projects.[39] Except for these subsidized projects, gas-fired generators have not been an attractive prospect for outside investors. At this writing, only 3.6 % of total electric capacity is fired with gas. An interruptible gas market would address many of these problems, but such a market is incompatible with an infant gas industry that has to find consumers for the large (and growing) Bolivian supplies.

Systemic Risk

In the old system, the federal government regulated the behavior of the concessionaires and the state governments decided the conduct of their own enterprises. As the system grew to take advantage of the large economies of scale and the potential to spread risk across the entire country's water basin's, Eletrobras oversaw investment planning and managed risk on behalf of the entire country—at times incurring the wrath of state generators, such as when Eletrobras put its own priorities (e.g., dispatching Itaipu power) ahead of the others. Ultimately consumers were expected to bear the risk of improper investment strategies in the cost-based tariffs that they paid. When supply was excessive, consumers paid higher tariffs than necessary—the Averch Johnson effect of regulated utilities over-investing consumers' money in power systems—and when supply fell short, as in severe drought, administrators forced reductions in consumption.

The reforms triggered by privatization have radically reallocated risk. Risk management is decentralized, and there is no coordinated, strategic view of the future.

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[39] In addition to subsidies from government. Petrobras offered a hedging instrument that would reduce volatility in gas prices; however, the hedge raised the total price and made thermal power generation even less competitive. Moreover, BNDES offered soft loans for thermal power projects and Petrobras reduced the natural gas price for a set of emergency thermal power plants.

There is no guaranteed rate of return for power generators; nor do consumers face fixed tariffs. In theory, this new system was intended to shift more of the industry risks to generators and distributors who, as competitive firms, were expected to manage these risks better than state-owned enterprises. Unlike in the past, in this new context the Treasury would no longer be expected to provide funds for rash capital construction projects to avoid system risks that can be efficiently managed through the price mechanism. It took just a few years to discover that risk management in the power system is far more complex.

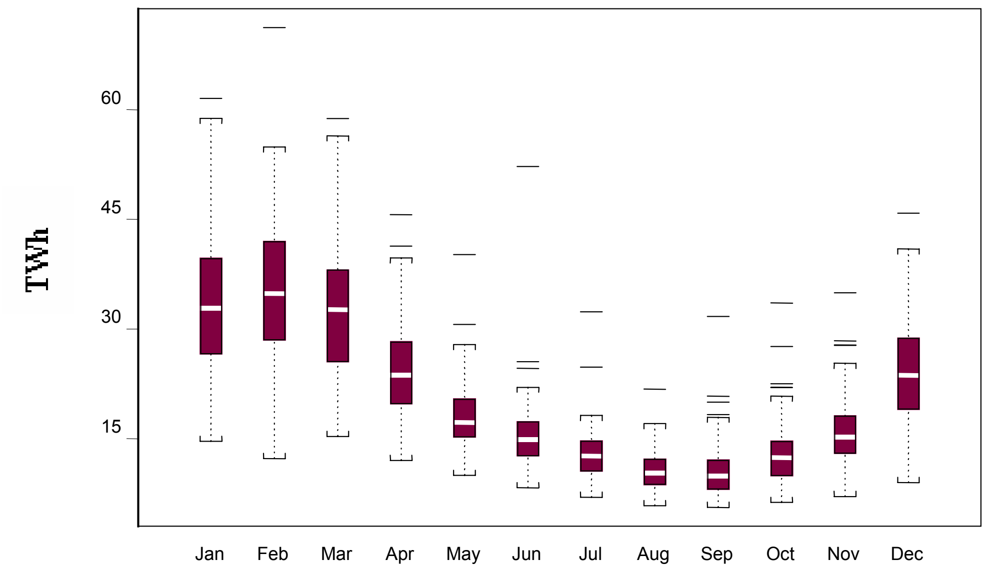
In practice, private investors proved unable to manage the risks in the system for at least two reasons. First, investors—especially those operating in foreign currency—can hardly manage large macroeconomic risks. For state-owned companies, currency risk was irrelevant because it was absorbed by the Treasury. For private companies, small shifts in currency or variations in demand are the normal part of business, but large variations have a devastating effect on the viability of investments.[40] Industry reformers neglected this issue, assuming naively that the Real macroeconomic stabilization plan would cement confidence in the currency and thus remove the risk of large swings in currency value. Large devaluations in 1999 and 2002 demonstrated that this assumption was wrong. These shifts in currency value also had large effects on the choice of technology—the consensus in early 1998 that thermal power plants could compete at the margin with new hydropower investments was completely reversed after the 1999 Real devaluation. Gas-fired plants required technology imports (with dollar indexed prices) and, in most plants that were envisioned, gas with dollar-denominated take-or-pay contracts.

The other systemic risk that individual investors proved unable to manage on their own was hydrology. Within the hydropower industry risk was managed through the mandatory MRE side-payments. ONS optimized the system, and the level of "assured energy" was a convenient benchmark for system planning. In most years the actual power available was far higher than the "assured" amount (figure 10), and ONS assumed that

[40] Private investors can hedge in the financial markets to protect their cash flow from the risk of the domestic currency devaluation but its cost is prohibitive for large devaluations of the domestic currency.

thermal capacity would be available in case of shortfall. But ONS did not have responsibility for assuring that such capacity was actually available. There were capacity payments to thermal generators; and the ONS was perveived as a hydropower club that sought, first and foremost, to shift risk away from owners of hydropower stations. For example, under the ONS dispatch and the MAE clearing mechanism hydropower generators received additional revenues from their sale of "secondary energy" in the spot market, but they were allowed to deplete their reservoirs at no cost. As potential power is depleted from the reservoirs, the scarcity cost of power increased and the spot price rose—which provided further benefit to the hydropower plants while penalizing consumers. A better system would force hydropower plants to offer compensation to society for the scarcity created when they release water from the reservoirs and/or compensation to thermal plants for the supply security they provide.

Figure 10 – Seasonal and annual variation of hydropower production potential in the Southeast.
The upper and lower limits of the box-plot figure show the fluctuation in the energy inflow to the South-East hydropower plants reservoirs in the 70 years of historical data (1933-2002). The white strip in the middle is the median. The red box represents the second and third quartile of data. The bars outside the limits are the outliers.



Source: ONS

A third systemic risk surrounds the projection of demand for power. In a cost-recovery regime there was no economic risk when assumptions about future demand proved to be excessively bullish. Indeed, the Eletrobras´ coordinating bodies usually assumed that economic growth would be buoyant, with the result that a substantial reserve margin was a constant feature of the Brazilian power system. This approach was justified by the fact that the social cost of power shortage would be much higher than the cost of over-investment in surplus, and when power consumption was growing rapidly the extra capacity would not remain spare for long.

The context is radically different in the competitive power market where there is no guaranteed return for projects and where (unlike in many countries, such as in Argentina) the market has no system of capacity payments to compensate the builders of under-utilized "spare" capacity. Volatility in economic growth introduces additional risk to investors. Moreover, the power shortage of 2001 revealed still another unanticipated risk: when power prices rose to reflect the scarcity, users found numerous ways to reduce their load. In all, about 10% of the load was shed permanently—about two years' total growth. Mindful of the problem of planning, the government created the Committee for Expansion Planning (Comitê de Planejamento da Expansão – CCPE) to amalgamate each companies' projections for future demand. The experience with CCPE underscored the severity of the problem: CCPE never actually operated.

The difficulty of the planning task is revealed when one attempts to estimate demand for power over just the next decade to square that estimate with a plan for supply. In the late 1990s Eletrobras forecast power consumption at 589 TWh in 2010, on the assumption that the economy would grow at 4% annually over the period (Eletrobras, 1999). By their estimate, US$ 4.7 billion in investment would be needed each year, half for power plants and half for transmission and distribution. Yet more recent demographic studies made after the 2001 census show a sharp reduction in the birth rate, suggesting that population will grow at only 1% a year. Power supply is already available to 95% of the population;[41] the period of heavy industrialization is drawing to a close; GDP growth during the last two years has been much lower than the Eletrobras assumptions, and the forecast for 2003 is 1.5%. Taking all these factors into account, consumption closer to 440 TWh seems more realistic. For any individual project investor, the difference in projections (one-third) will determine whether projects exposed to market forces are profitable or money-losers. It is no wonder that the only place where privately owned generators have found profitable investments is in the hydro system—where insider control over dispatch and socialization of risk across all hydro generators made investments almost a sure winner.[42]

[41] The access to power supply is still very low in rural areas of the Amazonian Region (18%) and the Northeast (41%).

[42] Buyers of existing (i.e., "brownfield") hydro assets in the privatization auctions have generally found the investments worthwhile. Some purchasers of hydro concessions that had already been through project review found the investments profitable—because the risk that project review (including increasingly

A Case Study: The 2001 Drought

Ever since the 1930´s, water regulation has been oriented to serve hydropower generation, with other services (irrigation, transportation, domestic and industrial consumption) somewhat subsidiary. In most places water supply was so abundant that these multiple services did not create conflict, but in the interior Northeast the water supply along the São Francisco River was already over-tapped by the early 1990s. Mindful of this tension, the newly elected new governor of Minas Gerais, Itamar Franco,[43] seized the Furnas power plants in his state's territory—nominally to oppose the privatization but mainly to show visibly his rivalry with President Cardoso. His actions touched off a political row that halted the privatization of the hydropower plants.

With privatization at a stalemate, private investors were also loath to build thermal plants—despite the fact that these plants would be essential to fill the hydropower gap in dry periods. By accident, this period of political crisis at the end of 1999 also marked the beginning of a drought period. ONS warned the government that reservoirs were at a low level. Good rains that year partially refilled the reservoirs—averting crisis, for a season (figure 11).

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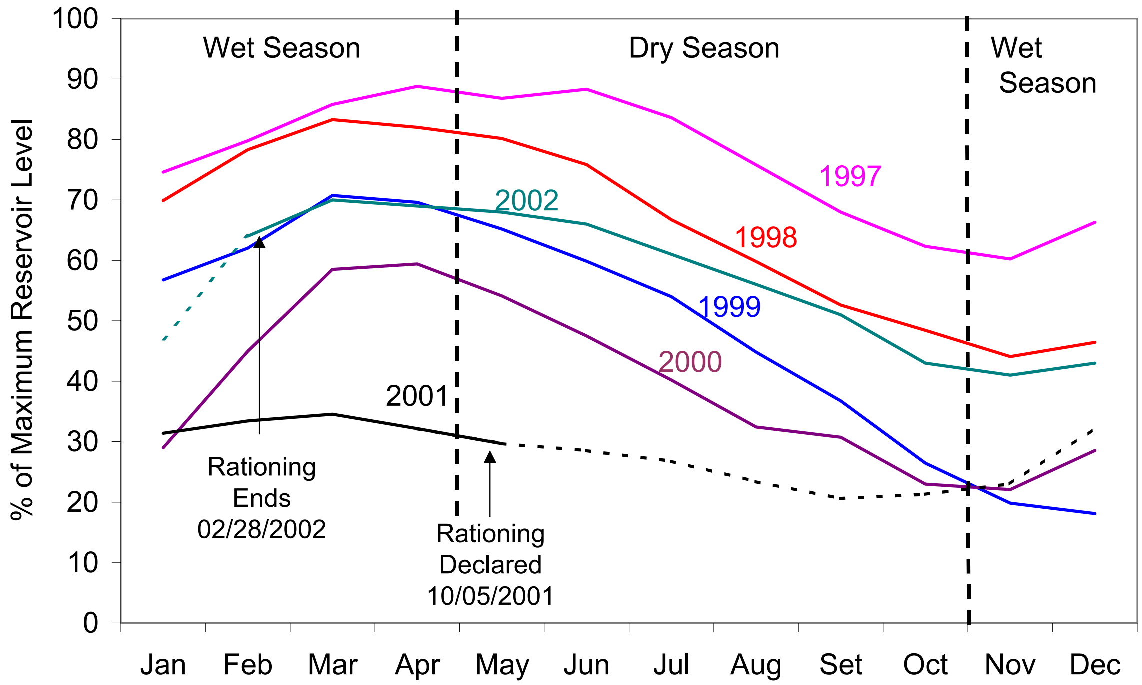
rigorous environmental review) was extinguished. But no wholly "greenfield" generators have turned a profit.

[43] The battle in Congress for the constitutional amendment that allowed a second term for president Cardoso moved ex-president Franco from the government coalition to the opposition.

Figure 11 - Depletion of Southeastern Water Reservoirs (Jan/1997-Apr/2001)



Source: ONS

The Minister of Mines and Energy took command of the situation with a massive emergency action plan for thermal power plants. Through an opaque process he announced a list of thermal power plants, totaling 6.6 GW of capacity, that were eligible for special incentives. Pressure to extend these incentives more widely led investors to nominate a total of 17 GW of capacity (table 3). Several of these projects were joint ventures between private investors and Petrobras, the country's sole supplier of natural gas.

Table 3 – Brazilian Thermal Emergency Plan

Power Plant	Proposed Capacity (MW)	Site	Investors	Operating Capacity MW	Under Construction MW
			GAS COGENERATION		
Vale do Açu	102	RN	Iberdrola/Petrobras	-	-
Sergipe	460	SE	Energisa/Petrobras	-	-
Termobahia	450	BA	ABB/Petrobras	-	-
Termorio	1,160	RJ	Petrobras/PRS/Sideco	-	1,160
Cubatão	950	SP	Sithe/Marubeni/Petrobras	-	-
Rhodia Paulínia	100	SP	Energyworks	-	-
Rhodia S. André	88	SP	Energyworks/Pirelli	-	-
Alto Tietê I e II	230	SP	EDP	-	-
Capuava	220	SP	Rolls Royce	-	-
Valparaíso	240	SP	CVE – Soc. Valparaiense	-	-
Ibirité	850	MG	Petrobras/Fiat	235	452
			CCGT		
Dunas	120	CE	BP-Amoco/Repsol-YPF	-	-
Paraíba	460	PB	Gaspetro/Paraíba Gás	-	-
Termoalagoas	500	AL	Alagoas Gás	-	-
Termopernambuco	720	PE	Chesf	-	
Vitória	450	ES	Escelsa/Petrobras/CVRD	-	-
Norte Fluminense	725	RJ	Eletrobrás/Petrobras/Light/ Cerj/Escelsa	-	725
Cabiúnas	500	RJ	Petrobras/Light/Mitsui	-	-
Riogen	78	RJ	Enron	-	-
Poços de Caldas	1067	MG	Cemig	-	-
Juiz de Fora	480	MG	CFLCL	82	-
Santa Branca	500	SP	Eletroger	-	-
Vale do Paraíba	240	SP	EDP/Petrobras	-	-
Araraquara	550	SP	EDP	-	-
Paulínia	945	SP	Flórida Power/Petrobras	-	-
Paulínia II	500	SP	DSG Mineração	-	-
Carioba	700	SP	CPFL/Intergen/Shell	-	-
ABC	180	SP	El Paso/GE/Initec/ITS	-	-
Bariri	180	SP	CGEET	-	-
Cachoeira Paulista	350	SP	EDP	-	-
Indaiatuba	480	SP	EDP	-	-
Taquaruçu	300	SP	Duke Energy	-	-
Araucária	480	PR	Copel/Petrobras/El Paso/BG	480	-
Termocatarinense	750	SC	Petrobras/Celesc/SC Gás	-	-
Gaúcha	300	RS	Petrobras/Sulgas/Techint/CEEE/Ypiranga/RGE	-	-
Termosul	250	RS	AES Brasil	-	-
Campo Grande	480	MS	Enersul	-	-
Corumbá	340	MS	CVRD/Petrobras/EDP	-	88
Cuiabá II	180	MS	Enron	-	-
Termonorte II	426	RO	Eletronorte	-	180
Manaus	64	AM	Manaus Energia	-	-
			GAS		
Termonorte I	100	RO	El Paso	-	-

Pitanga	70	PR	Copel/Gaspetro/Inepar/Teig	-	-
COAL (C) AND PETROCHEMICAL WASTE (W)					
Cofepar (w)	616	PR	PSEG/Petrobras/Ultrafértil	-	-
Figueira (c)	100	PR	Copel/C. Carbonífera do Cambuí	-	-
São Mateus (w)	70	PR	Copel/Petrobras	-	-
Sul Catarinense (c)	400	SC	Carb.s Criciúma e Metropolitana	-	-
Seival (c.)	250	RS	Copelmi Mineração	-	-
Candiota III (coal)	350	RS	Eletrobrás	-	-

Source: MME

Although MME authorities were optimistic about the success of their thermal emergency plan, four reasons explain why private investors were hesitant. Environmentalists were opposed to the inflexible dispatch of thermal power plants, which would waste hydropower capacity while fossil fuels were burned. Second, distributors were unwilling to give these generators a purchase power agreement at a wholesale price above the level capped by Aneel. In that context, MME had expected Eletrobras, as the wholesale power company of last resort, to absorb the difference in price—a very unattractive prospect for Eletrobras. Third, the incentives for investors included large loan packages from BNDES earmarked for Brazilian-made equipment; yet a large share of the equipment in combined cycle power plants would need to be imported. Fourth, investors were wary of the risk in gas prices. Unsurprisingly, few thermal power plants projects moved forward—only for projects that had joint investment with Petrobras, which offered interruptible gas supply contracts, went ahead.

At the beginning of 2001 the hydropower reservoirs were at a historically low level in the southeast and the northeast—the two largest hydropower producing regions. The 2001 rains were unfavorable—in the northeast the rains were the worst on record—and ONS projected that the reservoirs would be completely depleted before the beginning of next raining season, if consumption was not drastically reduced. (ONS suggested a 20% cut in consumption would be needed to avoid the collapse of the power system.) The Minister of Mines and Energy resigned; the President stripped Aneel of its regulatory authority and assigned a special task force, headed by the Minister of Civil Affairs, with responsibility for managing the power crisis. A consumer quota was introduced by the task force to induce the needed 20% in power consumption. Consumers would be liable for a substantial tariff penalty for consumption over their quota[44] and those who exceeded their quota twice would have their power supply cut. Small consumers who beat the quota would receive a bonus and large consumers were offered the possibility of consuming above their quotas if they purchased surplus quotas from other consumers who had made extra reductions. The trade of power quotas between large consumers was made at bilaterally negotiated prices—several bourses emerged to trade the quotas. Initially, prices were extremely high but converged progressively converging to about double the normal level.

Consumers´ reaction to task force measures was unexpectedly constructive[45]. Average consumption dropped below the 20% quota, and the government avoided the scenario that it feared most: rolling blackouts. The year 2002 raining season was favorable and reservoirs rose to nearly normal levels once again. Moreover, moved by the perception that power shortage would result in high prices in the wholesale power market, thermal power projects that were already under construction speeded up their availability to the beginning of the year 2002[46]. As the power supply moved back to glut the consumer quota was removed. However, the power crisis produced fundamental changes.

The drastic reduction in the industrial output forced by the power shortage produced a 2% drop in the expected GDP growth for 2001. Because the task force regulations disregarded contracts, substantial conflicts between generators and distributors arose. The government produced a grand settlement in which BNDES loans to the generators and distributors compensated them for their financial losses, consumers saw their tariffs rise (2.9% for domestic consumers and 7% large consumers), and the extra revenues where channeled back to the generators to repay the new BNDES loans.

[44] Large consumers, for example, were obligated to pay roughly US$ 240 for each MWh consumed over their target.
[45] Domestic consumers that were able to reduce their consumption below the target received a financial bonus that was used to reduce their normal power supply tariff.
[46] Keen to find consumers for its large take-or-pay natural gas contract in Bolivia, Petrobras is a partner investor in most of these projects.

Forced to reduce consumption, consumers changed to more efficient power appliances and altered their behavior. The market for efficient light bulbs, smart air conditioning, small generators for peak shaving and cogeneration boomed, producing a fundamental change in the level and shape of the power demand curve for Brazil. ONS estimates that these changes caused a permanent reduction in power consumption of at least 7%.

This change should not have caused persistent problems for generators. If the Brazilian economy had been able to resume its trajectory of growth the overcapacity would have been apidly absorbed. Unfortunately, after a short recovery in the first half of 2002, another large devaluation of the domestic currency plunged the Brazilian economy into a new crisis. At this writing (2003) power consumption from the grid is hovering at roughly the same level of the year 2000, leaving roughly 7 GW of power supply capacity idle and increasing the average costs of the power companies. The large devaluation of the Real in 2002 required a sharp rise in domestic interest rates—to prevent a further slide in the currency—and further multiplied the costs to the power. Several distribution companies are now in dire financial straights and are contemplating breaching their contracts with creditors and suppliers.[47]

For the government, the political cost of the power crisis was enormous. Consumers could not understand why they were penalized, with higher tariffs, when many actually exceeded the government's expected reduction in consumption. Investors are unhappy as well, with some foreign investors signaling that they want to sell their companies[48]. The credibility of government's ability to assure provision of basic public services was damaged seriously by the power shortage episode.[49]

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[47] At the beginning of 2003 Eletropaulo (owned by the American firm AES) declared that it could not pay a loan of R$ 85 million to BNDES. After a long and difficult negotiation, BNDES and AES reached a deal in September 2003 that waved the interest charge (US$ 118 million) due to the BNDES on the still outstanding principal of US$ 1.2 billion.

[48] A small distribution power company (CEMAR), in the state of Maranhão, was actually abandoned by its foreign investor. Aneel is currently running the company and intends to restore the firm to financial viability and then sell it to private investors. This case reveals the many roles that Aneel is expected to play—at least,

The political costs of the power shortage were paid by the government in the 2002 presidential election. The leftwing opposition coalition achieved a landslide victory on a platform that included drastic reorientation of the power industry. Liberalization wouldgive way to more central planning; the privatization of power companies would be stopped. Private investors would be invited to participate in building new power supply—not least because the government could not afford that function—in partnership with state-owned companies. A variant on a cost plus tariff regime would replace the wholesale power market pricing mechanism; average costs would be used to fix the power tariffs for consumers; visions of a tariff regime in which Aneel would gradually remove its caps and tariffs would be allowed to approach real long-term marginal costs were to be scrapped. The hybrid market would tip decidedly in the direction of more state control.

Mindful of all the difficulties with the reform process, the new government sought ways to return to the earlier era. While it is impractical to reconstruct the state-owned enterprises, the government is instead attempting to create a privately owned but state-managed power system. Power purchase agreements (PPAs) allocated through bids will be the norm. Central planning will decide the location and quantity of new power. Hydropower, the new government declared, would be the preferred technology for future projects; thermal power plants would be expected to adjust their output to the hydrological situation. Yet the fundamental problems with this vision for thermal power—the systemic risk and the requirement for long-term take-or-pay gas contracts—are not altered. The wholesale power market will be replaced by a governmental administrator of contracts that will mix different power plants prices to produce a single supply average price for the distribution companies—much as under the national tariff policy in the 1970s.

New power plants will be required to bid their output in yearly auctions, and Aneel will subject these power contracts to a cap regime in which power costs are indexed

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when the government does not suspend its authority (as in the 2001 drought)—and the conflicts of interest that may arise when operator, regulator and future auctioneer are all embodied in the same institution.

[49] President Cardoso declared that he was unaware of the risk of depletion of the hydropower reservoirs until April 2002.

(through a mechanism yet to be decided). Distribution companies will be prohibited from generating their own power to supply their consumers but, instead, will be obligated to purchase power from the generators with successful bids. Reserve margin will be stipulated by the planning authority, and the cost of sustaining the margin will be passed over to consumers through a scheme akin to capacity payments that are recovered through higher tariffs. The Minister of Mines and Energy signaled in public conferences that the government intends to create a fund to protect investors from the currency devaluation.

All these elements are difficult to square. In 2003, Aneel started the first round of reviews of tariffs charged by distribution companies. Using a hypothetical "efficient" distribution company as a benchmark—a hypothetical that, in fact, does not exist anywhere in Brazil—it fixed the new base rate for distributors. It estimated the factor X on the basis of the opportunities for scale economies and the quality of the service provided by the distribution company. The distribution companies strongly criticized Aneel's methods. The system, as it is taking shape through implementation, looks much like the tariff rules that squeezed private investors and yielded the state-dominated system that created the mounting financing crises and needs for reform.

3. Conclusion

Although initiated by foreign investors, over the second half of the last century the Brazilian power industry was developed by state owned companies. By removing protections against currency devaluation (Cláusula Ouro), the Water Code discouraged foreign investors by making it difficult to assure a fair rate of return (in hard currency); as the foreign, private share of the power system dwindled the state owned power companies emerged to fill the power supply gap.

State-owned power companies did not need to worry about currency risk; a dog's breakfast of domestic fiscal resources and international soft loans made feasible the rapid expansion of these state-owned enterprises. The interconnection of regional markets and the technological option for hydropower allowed for substantial economies of scale and scope that substantially improved the performance of the Brazilian power sector. Technologically and financially, this system favored centralization—a role that Electrobras assumed.

Another turn of events—largely unrelated to developments in the power sector—produced a series of macroeconomic crises that eroded the financial situation of the federal government and key states. The immediate reaction to these problems—which were manifest, in part, in high inflation—was to keep power tariffs low, which exacerbated an already tenuous financial situation in the power sector. By the end of the 1980´s there was a consensus within the government and the industry on the need for institutional reform; potential winners and losers from that reform were well organized, and the system that emerged reflected their interests—notably the interests of hydroelectric operators.

The transition to democracy included a radical shift in Brazil's development strategy. The import substitution policies that protected domestic producers were replaced by liberalization, privatization and fiscal austerity. These pillars of reform also guided the effort at restructuring the power industry.

The need of fresh inflow of foreign currency to support efforts to stabilize the Real currency led government to focus first on privatization—indeed, it initiated auctions of key assets in the power system before it had established a regulatory structure (or even a tariff). In this whirlwind of crisis and response, opposition to the privatization of distribution companies was weak and disorganized. State governors were wary of privatizing their companies but convinced otherwise when up front loans from BNDES were dangled for politically popular projects; employees were persuaded to accept privatization with generous financial packages for early and voluntary retirement. Foreign investors, after an initial period of distrust, saw the price cap tariff regime introduced by BNDES as an opportunity to make a fair rate of return in a rapidly growing market. In their zeal to grab these assets, however, they overlooked the systemic risks—notably the risk that tariff regimes would be changed, that large currency devaluations would degrade their holdings, and a substantial drop in power consumption would make it hard to recover costs.

After privatizing some of the distribution companies, the privatization of the power generators proved much more difficult. Mindful of the GCOI warning that uncoordinated (competitive) dispatch of hydropower plants would cause a substantial drop in output, the government adopted a mechanism that managed hydropower dispatch as a single system and protected the owners of these plants from hydrological risk. This approach raised the price paid to hydro generators but moved the hydrological risk to thermal power plants and did not cause prices to rise sufficiently that thermal generators could compete.

Thermal power plants faced many difficulties in entering the market, notably with the fuel contracts that were available. The hydro-dominated system was constructed so that gas-fired plants could make a profit only if they operated on an intermittent basis, but interruptible gas supply contracts were not available, a situation made worse, ironically, by the large volumes of take-or-pay gas coming into the Brazilian market from the government-back Bolivia to Brazil gas pipeline. While outside investors were abundant and genuinely interested in building gas plants, few such projects actually came to fruition. Without much thermal power, a high dependence of hydropower generators, and no entity providing the strategic planning and financing of last resort, it was simply a matter of time before a crisis hit. In 2000 Brazil narrowly averted that crisis; in 2001 it hit with full force.

Analysts should draw a few lessons from the Brazilian power reform experience. First, if large plans for reform are afoot then the new regulatory regime must be carefully designed and put into place before privatization starts. Brazil's federal government—BNDES in particular—was enamored of the short term macroeconomic benefit of an up-front inflow of fresh funds to the Treasury—but its haste to sell has provoked fundamental flaws in the power system and caused long term losses that will eclipse the early gains for the Treasury.

Second, the introduction of competition in an industry that has for very long time operated under monopolistic regime introduces risks for power companies; a regime is needed to share these risks. The incumbent clusters of interest will search for a regulatory scheme that protects their risks and shifts them to other players. The incumbent interests are typically well-organized and have ready mechanisms for voicing their views in the political arena while the newcomers struggle to find a voice.

Third, consumers place quite different values on the reliability of their power supply. The trade in quotas among industrial consumers indicated some consumers were prepared to pay more for reliable power supply while others readily curtailed their consumption in exchange for a reward. Moreover, there is an enormous potential for efficiency improvements by end users that can be conveniently explored if the correct price signal is offered to consumers.

Fourth, privatization of the power system does not remove the government's responsibility to assure reliability. There are systemic risks that no market player can assume individually, especially when foreign investors with exposure to currency risks are operating alongside local state and private investors. Government must assume these systemic risks—failure to do so will jeopardize the benefits of reform and also expose the government to an unruly electorate.

Acronyms

CNAEE - National Council for Water and Power
DNAEE - National Department for Water and Power
IUEE – Unique Tax on Power
GCOI Coordinating Committee for Operating the Interconnected Grids
GCPS Coordinating Committee for Expansion Planning.
CRC – Result Compensating Account
BNDES - National Bank for Development
RGG - Global Reserve for Reversion
MME - Ministry of Mines and Energy
ANEEL - National Power Regulator
ANP - National Oil Regulator
ANA – National Water Regulator
PROCEL – Power Savings Program
REVISE – Electricity Sector Institutional Amendment
SINTREL - National Power Transmission System
BNDES - National Bank for Development
ONS - National System Operator
MAE - Wholesale Power Market
MRE - Power Reallocation Mechanism
Coex – MAE's Executive Committee
ASMAE - MAE's Administration Company
CCC - fossil fuel account
CCPE - Committee for Expansion Planning

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