Case Study From

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Brazil's Power Market Crisis[1]

Brazil has one of the largest hydroelectric systems in the world, with gross 2002 capacity of 61,000 MW, representing 88% of all the power in the country that is connected to the national grid. Additional sources of power from nonhydroelectric generation come from natural gas (4,600 MW), fuel or diesel oil (4,800 MW), nuclear (2,100 MW), and coal (1,400 MW), some of which is not connected to the national grid. The demand for power is projected to grow" at an average of 3400 MW per year"[2]. This is more than double the rate at which new capacity has been added over the last two decades.

Such a high dependence on hydroelectric generation results in relatively cheap power—on the order of US$22 (R$62) per MWH average for all of Brazil at the wholesale level. However this dependence comes at a price. Approximately every four years, Brazil suffers a drought which can severely deplete the reservoirs and cause a shortage of power. In 2001, Brazil experienced the most drastic shortage ever, forcing the government to ration power in order to prevent extensive blackouts. In the heavily populated and industrialized Southeast region, cutbacks in usage from 15 to 25% were required from the industrial sector at great cost to the economy and the working population.

- *What were the underlying causes of the 2001 Power Crisis in Brazil?*
- *What options are available now for Brazil to strengthen its national power system to insure sufficient generating capacity in drought years and prevent future power crises? List the pros and cons of each option.*
- *Should Brazil commit to a program to encourage investment in gas-fired generation, and what policies would be needed to attract such investment?*

Electric Sector Overview - 2002

The Government is facing challenging times for the power industry. The privatization model proposed in 1996 was abandoned halfway, as most of the distribution was privatized, but not the generation. A total of 64 regional electricity companies operate in Brazil, with around 70% of the distribution under private control. There are currently 12 foreign groups controlling 26 distribution and generation companies in Brazil. Many of the largest utility companies in the world, including EdF, AES, Iberdrola, and Duke Energy, now operate in Brazil.

Today, only 15% of the generation is private. Electrobrás, a federal generation holding company, controls 41% of total installed capacity, while regional state-owned companies hold most of the remainder. There are no plans currently to proceed with the privatization program, although new capacity is open to private investors.

[1] This case study was prepared using publicly available information.
[2] Daniel E. White, et al., "The right and wrong ways to attract investments," *Global Energy Business*, March/April 2002, p. 45.

As a result of the institutional reform process begun in 1996, new regulatory agencies were formed that were directed to establish regulations to create an orderly power market and encourage investment.

- **ANEEL**. ANEEL is the electric sector regulator and supervisor agency. It promotes the auctions for contracting with public service utilities for electric power production, transmission and distribution as well as granting concessions to utilize the hydroelectric potential of the abundant rivers. It also manages the concession of electric power public services permission contracts, regulates tariffs and establishes the general conditions for contracting the access and the use of electric power transmission and distribution systems by utilities and free consumers.
- **MAE**. The Wholesale Energy Market (MAE) is where all electric power purchase and sale transactions in the Brazilian Interconnected System are carried out. MAE started official operations on September 1, 2000. However MAE does not work currently. Regulations are being restructured to allow better competitive bidding for generation.
- **ONS**. The National Electric System Operator (ONS) is responsible for operational planning, scheduling, and dispatch of the system generation with the objective of optimizing the national electric energy system. It contracts and manages the electric power transmission services and defines the operational rules for the basic net transmission installations, which are then approved by ANEEL.

Under the centralized dispatch rules (only for plants higher than 30 MW), inflexible plants have first priority, followed by economic dispatch based on the variable costs declared by each generator. The variable cost of hydroelectric power is close to zero, meaning that hydroelectric generators will be dispatched ahead of any other primary source except nuclear which is classified as inflexible. Even a thermal power plant with a PPA will be exposed to dispatch rules unless it can declare inflexibility. (An example of an "inflexible plant" would be a small cogeneration facility that produces process steam for an industrial user, along with electricity that is sold on the grid.)

"Demand should grow an estimated 5% in 2003. Industry estimates that some 30 GW will have to be added to the grid by 2015."[3] To achieve this target would probably require some US$60 billion for system expansion alone (US$25 billion in generation, US$25 billion in transmission, and US$10 billion in distribution). Brazil's power industry is feeling the effects of too little investment. In the last five years, it received less than half of the US$8 billion to US$10 billion a year needed to keep up with demand, says Paulo Feldmann, vice-president at Ernst & Young in São Paulo.[4]

This projected demand growth presents a real conundrum for the government. On the one hand, there are still ample hydroelectric sites that could be developed and could provide power at lower rates than gas-fueled generation. On the other hand, unless more gas-fueled generation is developed, Brazil will always be subject to the drought which occurs about every four years. The last dry year occurred in 2001 with devastating impact on the economy. (See the last section of this case study for an exposition of the impact). Because the rate of construction of new generation has been about half the rate of demand growth for the past two decades, the country has reached a critical point and must increase capacity on a sustained basis.

[3] *Power Market in Brazil,* UK Trade and Investment, 2002.

[4] "Did Brazil's Lights Just Flicker." *Business Week*, May 7, 2001.

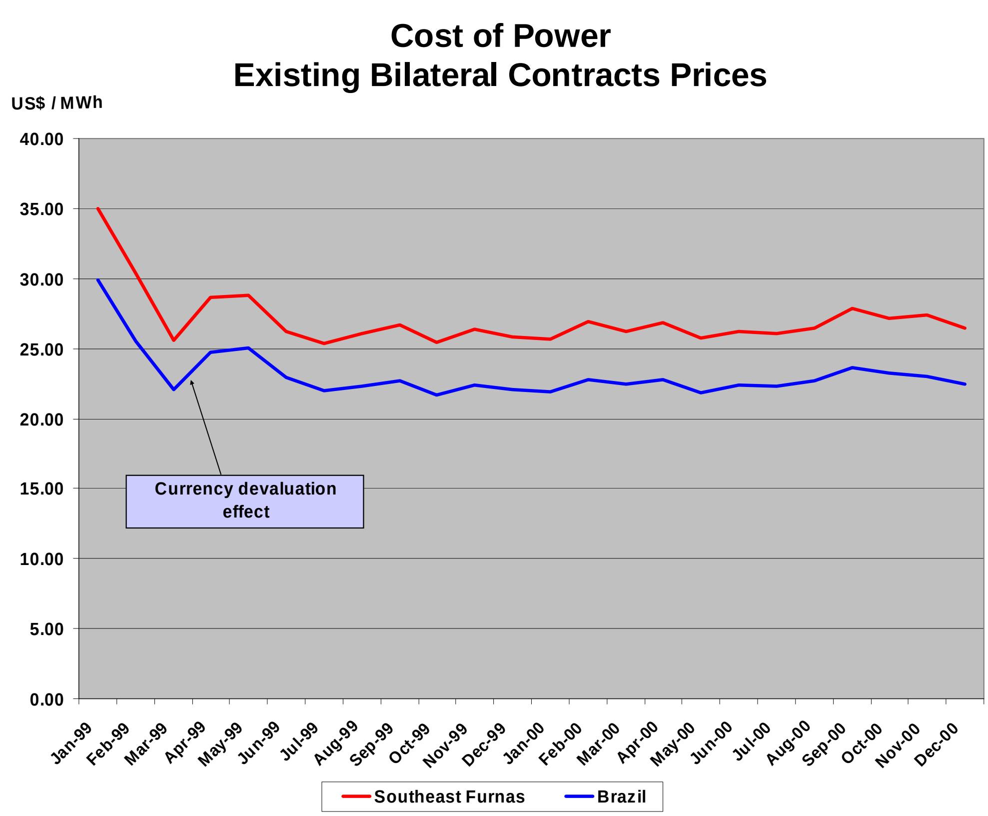
Electricity Prices and Currency Devaluation

Since 1995 when the Real was created to replace the old currency as part of the program to eliminate hyperinflation, and until 1999, the Real had been allowed to fluctuate within a narrow range and was defended vigorously by the Central Bank. When the Asian currency crisis hit in 1997, the contagion spread to Latin America and the Real came under tremendous pressure. In 1998, Brazil obtained a commitment from the World Bank for US$41 billion to shore up the economy and protect the Real which at the end of 1998 still traded around R$1.10:US$1.00. However, economists estimated at the time, that the Real was overvalued by at least 30%. Finally the pressure became too much and in January 1999, the Real was cast free and allowed to float. Almost immediately, the Real fell to R$1.60:US$1.00 and then over the next six months went as low as R$2.10 before easing back to around R$1.80. In early 2004 it traded around R$2.93:US$1.00.

When the Real was devalued, the regulators immediately froze electricity prices at the retail level. If electricity prices had been allowed to maintain parity with the dollar, it could have triggered huge inflationary pressures, causing massive hardship on industry and the population in general with severe economic and political consequences. Thus the retail price in Reais (Reais is the plural of Real) was capped and allowed to move up only gradually. It has never recovered in dollar terms to predevaluation levels.

Figure 1 shows the effective cost of power in US dollars. Note that immediately after the devaluation the dollar-equivalent price dropped by US$10 per MWH in the heavily industrialized Southeast region (US$8 per MWH over all Brazil) and has never moved much above that price. This hit the companies which, prior to 1999, had flocked to invest in the newly opened power sector very hard financially. By the time anyone recognized the threat of a currency devaluation, hedging had become prohibitively expensive and the foreign power investors were fully exposed. Almost every company that invested prior to the devaluation has lost money on its investment.

Figure 1



Hydroelectric Generation

Many of Brazil's hydroelectric plants have very large reservoirs that are capable of storing enough energy to meet all current power demand in years of normal rainfall. During normal seasonal fluctuations in both rainfall and demand, this storage is sufficient to meet all peak requirements. Prudent operation of hydroelectric plants would dictate that they be run at 55% of capacity so as to maintain sufficient reservoir levels for the dry years. (The 61,000 MW of hydroelectric capacity referred to in the introduction represents 100% of capacity. At 55% of capacity, the output would be 33,550 MW or little more than the average annual demand of 32,300 MW.) However, since the pace of new construction has not kept pace with demand, these plants were often operated above 55% capacity to handle both normal and peak loads. Thus when the drought occurred in 2001, these reservoirs were well below the levels required to sustain normal generation. (See Figure 2)

There are also a number of river-run hydroelectric plants with no storage capacity. Power generation fluctuates with the amount of water flowing in the river. This is not a problem during wet years, but generation can be severely curtailed in a dry year. Thus it is even more crucial that hydroelectric plants with reservoirs be run prudently.

Figure 2

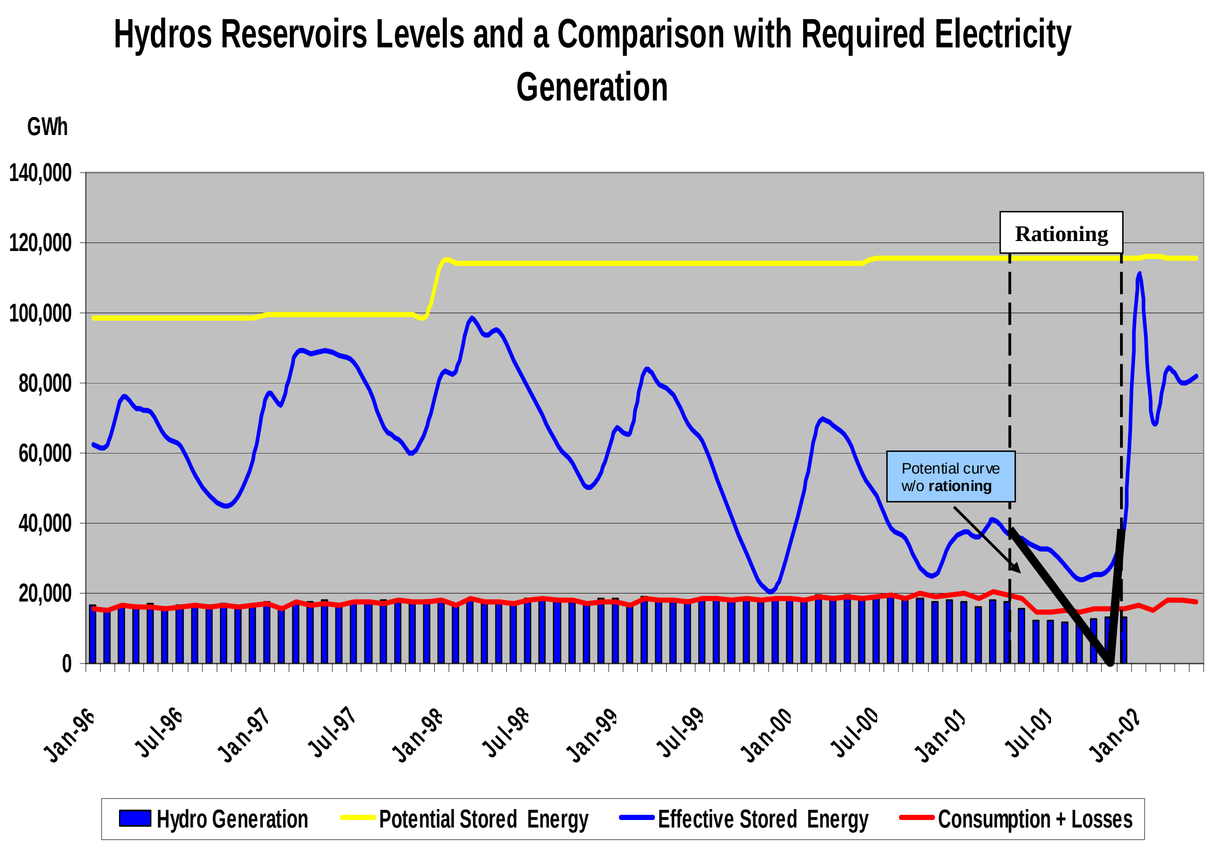


Figure 2 shows the total capacity of the reservoirs and the decline in actual generation capacity in the years leading up to the crisis in 2001. The yellow line is 100% of the reservoir capacity. The blue line depicts the actual potential energy stored in the reservoir (a direct function of water level) at any given time. The seasonal fluctuations are clearly evident. However because capacity construction did not keep up with the growth in demand, and because the reservoirs were operated at a rate above 55% starting in 1998 to meet both normal and peak demand, the water levels declined steadily from 1998 even in the years with normal rainfall. When the drought hit in 2001, there was insufficient reserves to meet the normal demand. The heavy black line demonstrates what would have happened to generation potential without rationing. The blue bars show the actual hydroelectric generation in gigawatt-hours for each month, while the red line represents average consumption and clearly demonstrates the effect of rationing. When the rains came in January of 2002, consumption did not return immediately to its historical level primarily because the economy was slow to recover and some demand was permanently lost. Many residential consumers changed their living patterns and never went back to their previous levels of electricity consumption. Several industrial users had adjusted their power usage through substitution or simply went out of business.

There is still an estimated 226 GW of untapped hydroelectric potential in Brazil. However, most of this potential is located far away from consuming centers. Two major hydroelectric projects are currently in the planning stage:

- Belo Monte, in the Xingu River in North Brazil, would be an 11 GW plant with a price tag of some US$6-8 billion including 3,300 km of transmission lines to reach the population centers. This project is highly controversial however, and has met with considerable environmental opposition because of the requirement to build 3 dams and flood 440 square kilometers of rain forest in the Amazon. The project sponsor, Electronorte has responded to this criticism by redesigning the reservoir to minimize the submergence zone by excavating two canals about a quarter-mile wide and seven and a half miles long to connect two portions of the Xingu River. According to Electronorte, this excavation would be the largest since the Panama Canal, and would reduce the amount of flooded land by about 65%.[5]
- A combination of two plants in the Madeira River would contribute total capacity of 7 GW and should cost around US$4 billion.[6]

The format being discussed would have Electrobrás responsible for one third of the investment with the private sector responding for the balance.[7] However, because of the environmental impact in the Amazon region, the World Bank has declined to provide financing. Thus the funding would have to be primarily derived from equity sources.

Gas-Fired Power Generation

At the start of the 2001 crisis, there were only 4600 MW of gas-fired power plants and another 4800 MW of diesel fuel-fired power plants, only a portion of which were connected to the national grid. As early as 1997, the government had set a goal of having at least 12% gas-fired power generation on the grid by 2010. Investors initially rushed to bid on the electricity distribution franchises being privatized under the new 1996 model and often bid up the price of the better franchises to uneconomic levels just to gain a foothold in the country expecting that a wide open merchant market would evolve. Companies, such as Enron and AES sought to be among the first to build new gas-fired generation facilities to utilize the gas flowing from the recently completed Bolivia-to-Brazil (BTB) pipeline. The BTB pipeline has capacity for 1 BCFD, much of which was targeted for future electric power generation. (A state-of-the-art, combined-cycle, gas-fired power plant will consume about 17 mmcfd for each 100 MW of power generated.) City-gate gas prices from the BTB pipeline were set by regulation to provide a favored price for power generation.

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[5] *Belo Monte Hydroelectric Complex,* Amazon Financial Information Service, December 20, 2001.
[6] *Power Market in Brazil,* UK Trade and Investment, 2002.
[7] Ibid

Then in 1999, the Brazilian Real was allowed to float with devastating impact on the companies who had spent heavily to purchase equity in distribution franchises and the few power generation facilities that were privatized. Those who had committed to build new thermal power plants under the new 1996 model were also crushed. Investments had been made in dollars, while projected returns were based on prices quoted in Reais under the assumption that the Real would continue to be pegged to the dollar. However, following the devaluation, ANEEL capped retail prices in Reais. Overnight, revenues were reduced to a point that they did not cover depreciation. At the same time, Petrobrás continued to charge for gas in dollars. Prices for some gas produced in Brazil were regulated, but gas from Bolivia was controlled by contracted rates priced in dollars. The net effect was that power generators were further squeezed between fixed fuel costs which had to be paid in dollars and revenues which were frozen in devaluing Reais.

Major foreign power companies such as Enron, Duke, AES, and others which had rushed to establish a position in the Brazilian power market were suddenly fighting to renegotiate debt, sell assets and downsize just to stay alive. Project financing in hard currencies evaporated. These and other foreign companies had no money or stomach for further commitments in Brazil. Any new gas-fired plants which had not begun construction were cancelled.

Petrobrás suffered along with the power investors. It had predicated its take-or-pay obligations for Bolivian gas, and its ship-or-pay commitments on the BTB, on a burgeoning gas-fired power plant market. It was thus forced to make payments (in dollars) for gas that it could not sell. Even though its purchase and shipment obligations were scheduled to ramp up to full capacity over a period of five years from 1999 to 2004, the demand did not materialize as anticipated because new power plant construction ground to a halt after the devaluation. In 2002, Petrobrás was committed to purchase and ship 600 mmcfd while demand was only 400 mmcfd.

In spite of the devaluation of the Real, the government continued to foresee a need for more gas-fired power generation in the mix to shield Brazil from the reduced hydroelectric power generation in the dry years. In early 2000, the government established a goal of 55 new thermal power plants (mostly gas-fired, combined-cycle plants) with a total capacity of more than 17 GW, to be commissioned by 2005.[8] (To fuel the plants with gas would have required around 3 BCFD and Petrobrás commenced plans, since abandoned, for a second BTB pipeline to supply the gas.)

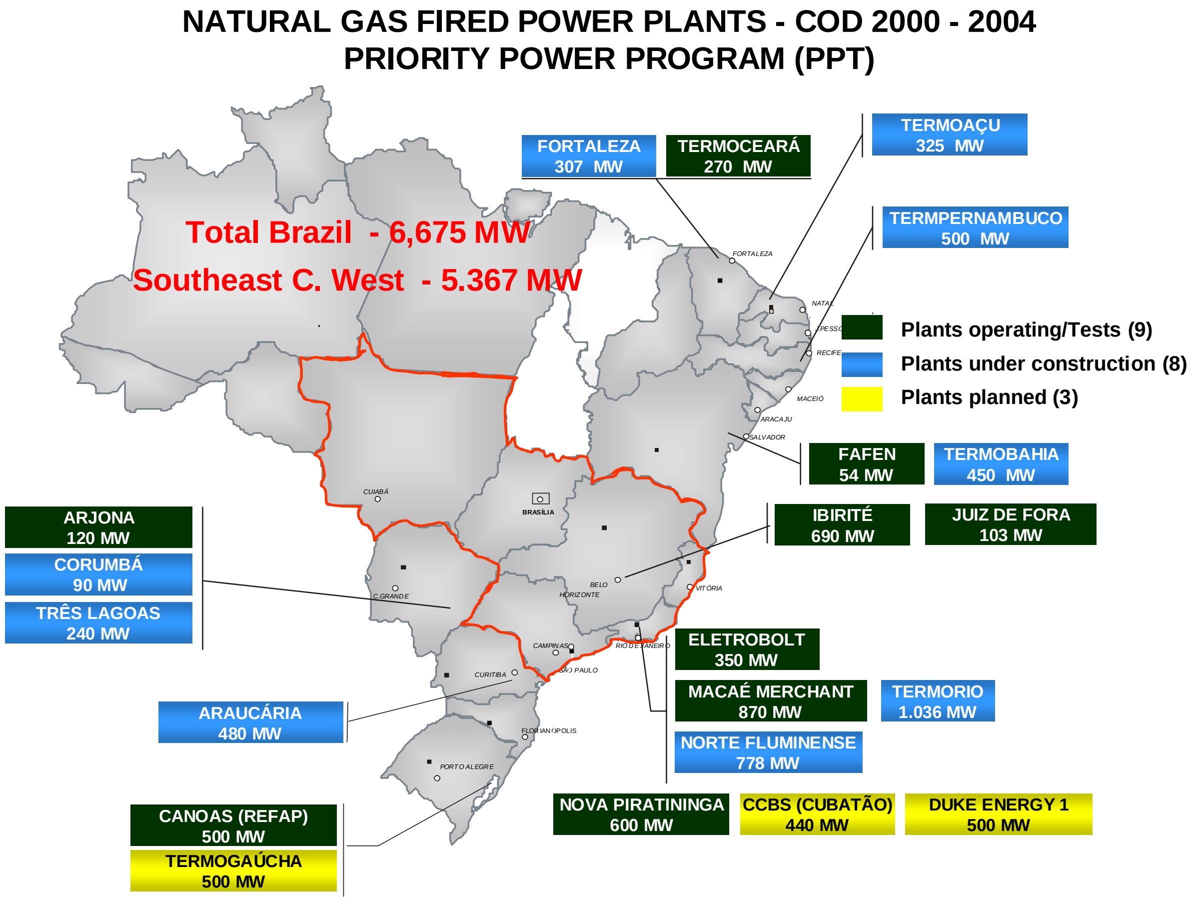
In order to encourage investment, the government simplified and streamlined the process for getting such plants approved and licensed (Priority Power Program). In addition, to alleviate investor concerns, Brazil set aside some aspects of the “pure” market approach. It established a fixed price for natural gas that developer/owners of fast-track plants would pay to Petrobrás. It also made it possible for Petrobrás to participate in projects either as an investor, tolling agent or both. Finally, the government used Electrobrás to sign firm PPAs which guaranteed a price for power, with capacity payments, for four years.

Investors remained leery, however, because there was no guarantee that a gas-fired plant would be dispatched. Capacity payments were not sufficient protection to the power generators if they were not dispatched because Petrobrás still required take-or-pay contracts on the gas. Therefore, the program fell far short of the goal, and as a consequence, Petrobrás frequently ended up in the lead developer role and often had to guarantee the power offtake.

[8] Op. cit., White 45

Figure 3 depicts the plants that were developed before the devaluation and those that were initiated as a result of the Priority Power Program.

Figure 3



The red outlined area shown on the map in Figure 3 is the critical Southeast, Central West region which consumes 61% of Brazil's power and which suffered the most during the 2001 crisis. Of the planned plants (yellow), the only one that was actually built was Termogaúcha in the south. Duke Energy hit its own financial crisis before commencing its thermal plant in the Southeast and cancelled the project.

The plant planned at Cubatão was a joint venture between Petrobrás and Mitsubishi and its cancellation was a telling indication of the problem the government has been having attracting new investment in thermal plants in spite of its Priority Power Program. As of the summer of 2002, Mitsubishi had arranged financing with the Japanese EXIM Bank and much of the preliminary engineering had been completed. All of the key governing contracts had been negotiated and were ready for signing. The 440 MW plant was to be in the Petrobrás refinery at Cubatão. Petrobrás was to own a minority share of the equity, operate the plant, provide the gas, and be responsible for the entire power output. Petrobrás intended to use 100 MW in the refinery and to sell the balance on the grid. The Petrobrás Board of Directors decided not to go ahead because the other thermal power plants in which Petrobrás had an equity stake (totaling about 4000 MW) were not getting dispatched and were costing Petrobrás money as a result.

Transmission System

In the next 10 years, Brazil will need to add some 38,000 km of transmission lines to the existing network of 73,000 km. In addition, the grid will require an additional 63,000 MVA in transformer capacity. Only around 4% of Brazil's electricity is supplied outside the national grid.

To achieve this expansion, around US$ 2 billion per year will have to be invested, of which an estimated 1/3 is expected to be provided by private investors and the remainder by federal and provincial generation and/or distribution companies. A total of 2,783 km of lines will be added to the grid in the period 2003-05, improving the stability of the grid. Although the new Government has ruled out privatization of existing assets, the auctioning of new concessions will lead to a private-dominated transmission market in the future.[9]

Southeast and Center West Region

The area hardest hit by the drought in 2001 was the Southeast/Center West region which is heavily industrialized and which consumes 61% of Brazil's power. Figure 4 displays the states incorporated within this region.

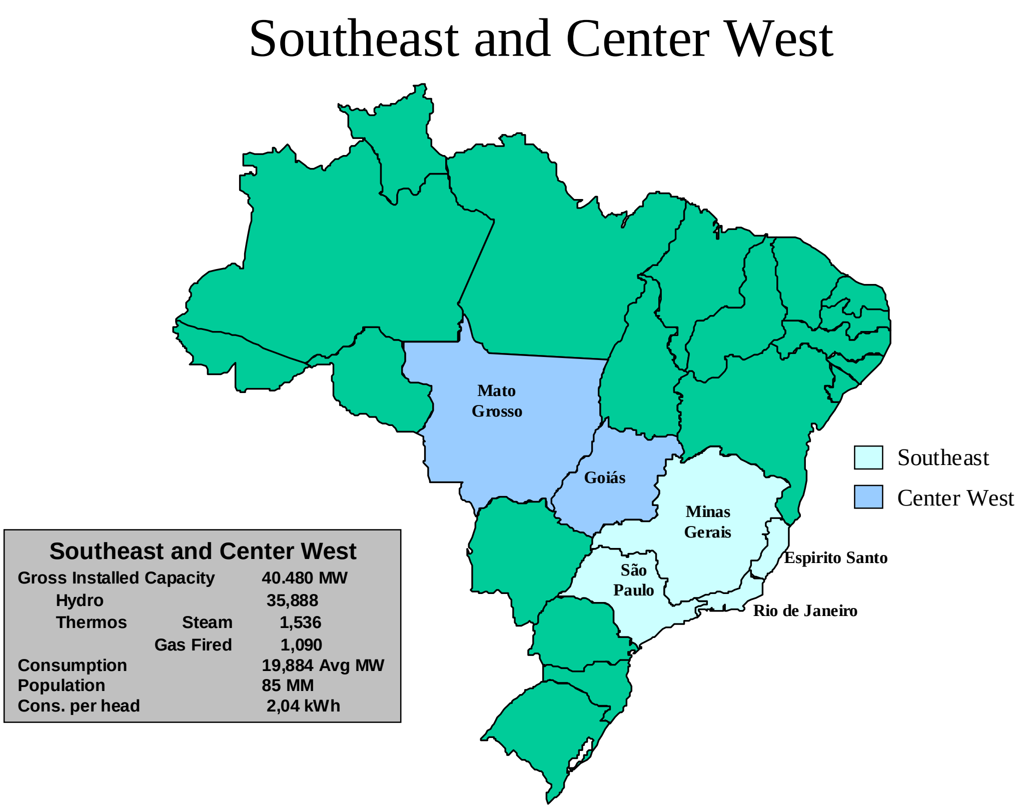


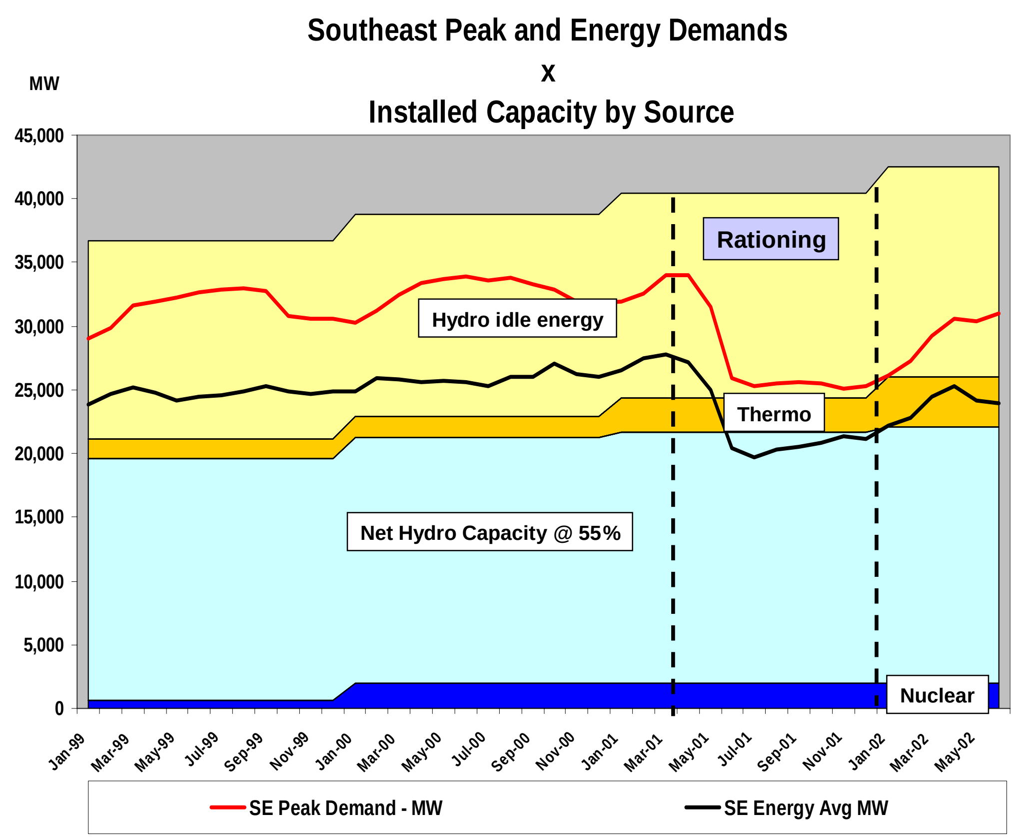
Figure 4

Figure 5 depicts the sources of power in the region and the average and peak demands. As stated earlier, prudent operation of hydroelectric power plants would dictate that they be run at 55% of reservoir capacity in order to maintain sufficient water levels to be able to ride out normal fluctuations in rainfall. However, as shown, the combined power generation

[9] *Power Market in Brazil,* UK Trade and Investment, 2002.

sources of nuclear, thermal and hydroelectric at 55% capacity would not have been enough to meet average demand, let alone peak demand. On average, hydroelectric facilities were operated well above the 55% level. Therefore when the drought hit in 2001, reservoir levels were insufficient to meet normal demand and rationing was required to avoid blackouts. As described in the next section below, this rationing program exacted a heavy toll in the country as a whole, but was even more devastating to the Southeast/Central West region with its heavy industrial base.

Figure 5



There are essentially three options for developing over the next 10 years sufficient generating capacity to supply reliable power to the Southeast/Central West region:

1. Develop the vast untapped hydroelectric potential of the northern Amazon region of Brazil. If enough capacity were developed so that the growing demand could be met without exceeding the 55% operating capacity limit on any hydroelectric plant, then residents and industry could continue to enjoy relatively inexpensive, reliable power for several more years. Such development would require additional major investment in high-capacity transmission lines up to 4000 kilometers long. Line losses over such distances would be quite significant.

   Two such projects, Belo Monte (11 GW gross) and Madeira River (7 GW gross) mentioned above, have drawn environmental opposition because of the necessity to flood a vast expanse of rain forest. Opposition is likely to become more vocal should Brazil aggressively pursue the development of its hydroelectric potential in the northern rain forests. The environmental issue could make it difficult to obtain financing for the projects.

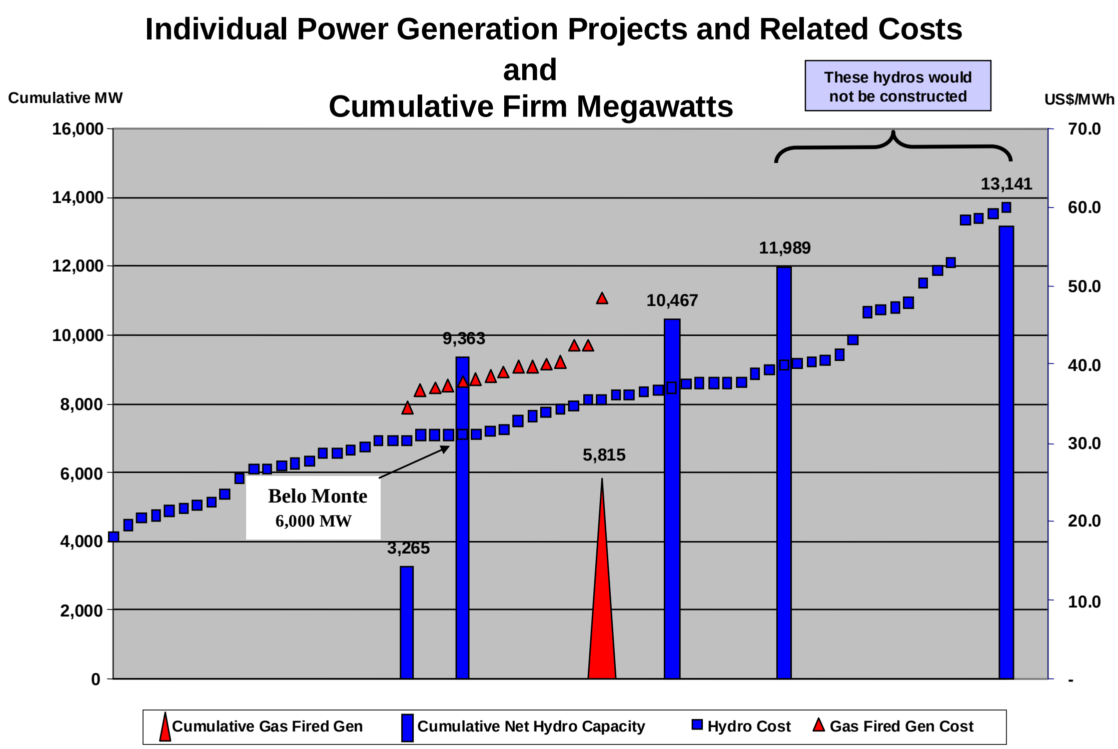
2. Create a regulatory environment that would attract investment in sufficient gas-fired combined-cycle generation to alleviate the loss of hydroelectric capacity in the dry years (17 GW over the next 10 years). Electricity rates would have to be raised from around US$22 (Brazil average) per MWH currently to about US$26 per MWH as the price of thermal power were averaged into the mix. Brazil would still enjoy relatively low power costs, but would have to overcome political opposition to increasing the rates by 20% to accommodate the higher price of thermal power.

   Fuel for new gas-fired power plants will not be a problem. The BTB pipeline continues to be underutilized with upwards of 400 mmcfd of unused capacity. In addition, in April 2003, Petrobrás discovered 15 TCF of new gas reserves offshore in the Santos Basin just 130 kilometers south of the main consumer, São Paulo State (Map in Figure 4).[10] Among the options Petrobrás is considering for this gas is an LNG export facility should it not need all the gas for internal consumption.

3. A combination of the above, perhaps going ahead with Belo Monte and some of the other least expensive hydroelectric projects while adding thermal power to the mix at a slower rate. However, without a change in the regulatory environment for thermal power, no additional gas-fired plants are likely.

Any of the above options will require a political consensus and commitment that has not been evident in the Brazilian legislature for decades. Figure 6 indicates the incremental cost of power that must be considered in selecting among the options.

Figure 6



The small blue squares in Figure 6 represent each of the potential hydroelectric projects that could be developed to serve the demand in the Southeast/Central West region. Each

[10] Nicola Pamplona, "Petrobrás: Santos basin gas reserves total 400bn m^3" *AE Brazil*, September 3, 2003.

square is one project without consideration of size. Some are as small as 50 MW all the way up to Belo Monte at 6,000 MW (55%). The scale on the right shows the incremental price per MWH that each plant would have to charge to earn a reasonable return after all associated costs including new transmission lines are taken into account.

The small red triangles represent the thermal power plants that are being considered. Again the scale on the right shows the equivalent price for power associated with each plant. The red triangles are only those thermal plants that have been proposed, including a few more expensive peaking plants. Many more gas-fired plants than are shown here, which could supply electricity in the US$40 per MWH range, could be built.

The blue bars (left scale) show the cumulative net hydroelectric power (at 55% of gross capacity) represented by all the blue squares to the left of each bar. Thus the first blue bar is the cumulative net capacity (3.3 GW) represented by the first 22 plants at the bottom of the cost ladder. The second blue bar (9.4 GW) covers only 4 additional plants but includes the huge Belo Monte project. By the time the third blue bar (cumulative net capacity of 10.5 GW) is reached, the power from each new hydroelectric plant would cost about the same as that from new thermal plants. The upper economic limit on hydroelectric plants would be reached at 12 GW and US$40 per MWH (fourth bar). The large red triangle indicates the cumulative capacity of all the proposed thermal power plants.

It should be noted that the Belo Monte project and the 2 plants proposed for the Madeira River represent a total of 9.8 GW (at 55%) out of the maximum of 12 GW that are economically feasible. The other 46 projects represented are small projects. The construction of that many projects in the rain forests would likely trigger strong environmental opposition. It may be worth the struggle to try to overcome the environmental objections to the large projects. However, a sustained campaign by the environmentalists would probably kill many of the smaller projects, although a few of them might initially sneak in under the radar screen while attention is focused on the 3 large projects.

The following table lists some of the key issues affecting the next 8 to 10 years to be considered in setting regulatory policy to encourage either thermal- or hydroelectric-dominated growth:

Thermal Growth	***Hydroelectric Growth***
• Higher cost of power	• Lower cost of power
• Politically Difficult to raise rates for electricity	• Politically easy unless project incurs environmental opposition
• Heavy reliance on government regulations	• More difficult to finance due to environmental impact
• Low volatility of supply	• High volatility of supply unless all 12,000 MW of economically viable plants are built soon and prudent operating practices are maintained
• Provides a ready market for Bolivian gas through 2010	• Strong risk of gas surplus for the foreseeable future
• A gas-fired combined cycle plant can be built in 2 ½ years	• Construction can take four to six years
• Capital costs are much lower	• Capital costs per MWH much

per MWH but operating costs higher	higher but operating costs almost nothing

Under competition (ignoring Petrobrás' take-or-pay obligations on the BTB pipeline and environmental opposition), the cheapest plants (hydroelectric) would be built first. After roughly 10 GW of hydroelectric additions, new thermal plants would become price competitive and would supply virtually all future power needs. However, even an optimistic construction schedule for these hydroelectric plants would leave Brazil highly vulnerable to the next dry cycle which could be expected in 2005.

Under the current regulatory and political climate in Brazil, which continues pretty much unchanged even after the lessons from the drought of 2001, it is questionable whether any new thermal power plants will be built as long as sufficient power is available in the normal years. Hydroelectric generators are regularly run beyond the prudent 55% capacity level during the years of normal rainfall in order to maintain low prices for power, thus discouraging new thermal plants. Given the penalty to the economy every time there is a dry year, and the continuing drain to Petrobrás of paying for gas it cannot use, new policies are required.

Economic Impact of the 2001 Drought

The economic impact of the drought was severe. GDP fell from US$602 Billion in 2000 to US$511 Billion in 2001, a loss of US$91 Billion. The GDP fell another US$58 Billion in 2002 before regaining US$40 Billion of that loss back in 2003 (2002 and 2003 numbers are subject to revision).[11] If these numbers are correct that would still leave Brazil some US$109 Billion below the peak GDP in 2000. While some of this GDP was lost because of the fallout from the Asian currency crisis in 2001 which resulted in the economic collapse of Brazil's major trading partner, Argentina, and the devaluation of the Argentine Peso in January 2002, much of the drop can be attributed directly to the rationing program required by the drought.

Even more devastating for the long term was the loss of new industrial investment that had been planned for Brazil. The rationing hit industry very hard. The government dictated that industry had to reduce its electricity use by 15% to 25% or face higher bills and blackouts. These mandatory reductions in usage varied by industry as follows:

15% Cuts	Food processors; footwear, leather, and textile manufacturers; auto and auto-parts makers
20% Cuts	Chemical and petrochemical plants; mining operations; integrated steel mills; producers of cellulose, lumber, furniture
25% Cuts	Producers of nonferrous metals, industrial gases, paper, cement

As a result many companies postponed or cancelled major investments. Alcoa, which shelved an aluminum smelter project when the 25% power cuts were imposed, is a prime example. Alcoa may not reinstate this project until it is assured there will be adequate power in all years. Plants such as these depend heavily on abundant and inexpensive electricity and cannot afford to shut down for lengthy periods.

"For the citizens of Sorocaba, an industrial satellite of São Paulo, Brazil, it was a heavy blow. On May 25, the local unit of Flextronics International Ltd. of Singapore, a manufacturer of info-tech equipment, announced it would not, after all, build two new

[11] Brazil Fact Sheet compiled by the Market Information and Analysis Section, DFAT, using the latest data from the ABS, the IMF and various international sources.

plants next to its factory there. The US$85 million investment would have created 500 new jobs. Why was it axed? Because there was no guarantee Flextronics could get a steady supply of electricity, owing to the widening power shortages in Brazil."[12]

Residential customers did not fare any better. In June of 2001 The Times (London) wrote:

> A decree has been issued to cut electricity use by 20 per cent by the end of this month. This applies to poorer homes consuming the equivalent of electricity for a radio, a TV and a fridge. Most middle class urban Brazilians will have to cut use by 70 per cent if they want to avoid 300 per cent fines on bills, or they risk being cut off.
>
> Middle class homes will have to turn off kitchen appliances, large fridges, freezers, electric showers, stereos, washing machines and air conditioners and resort to fluorescent light bulbs selling on the black market at £20 apiece.
>
> Rationing starts in earnest next week but many have started making reductions in the hope of getting favorable cutback targets from electricity suppliers. Skyscrapers have cut off air conditioners and operate only service lifts.
>
> Families with ailing relatives at home have resorted to expensive diesel generators to prepare for the predicted blackouts. Only the country's biggest state-run hospitals will be spared from rationing. Shopping centers are turning off escalators and reducing opening hours while cinemas and theatres will have to cut showings.[13]

Clearly the true cost of the drought in economic and personal loss is not reflected in the GDP numbers alone. Equally obvious is that the country must take action to ensure that it does not experience another such crisis during the next dry cycle. The investment required to meet the future power demands of this dynamic country, while huge, should be compared to the costs of another energy crisis of similar magnitude.

<u>Abbreviations</u>

BCF – Billion (10^9) cubic feet. 1 BCF = about 28.3 million cubic meters

BCFD – Billion cubic feet per day

mcf – thousand (10^3) cubic feet

mmcf – million (10^6) cubic feet

mmcfd – million cubic feet per day

TCF – Trillion (10^{12}) cubic feet

MW – Megawatt = 1 million watts, a rate of power production

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[12] "How an Electricity Shortage Is Blacking Out Brazil's Growth," Business Week Online, June 11, 2001.
[13] Martin Thompson, "Power crisis puts Brazil back in the dark age," The Times (London), June 1, 2001.

MWH – Megawatt Hour – the amount of electric power produced/consumed by a facility running at the rate of one Megawatt for one hour.

GW – Gigawatt = 1 billion watts or 1000 MW

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