THERMAL AND HYDRO INTEGRATION AND RISK MANAGEMENT IN THE BRAZILIAN ELECTRICITY SUPPLY INDUSTRY.

Tiago B. Correia, MSc* – Ministry of Mining and Energy
Ricardo G. de Oliveira, Dsc – Energy Program, COPPE/UFRJ
Paulo B. Correia, DSc – Energy Program, University of Campinas
Adriano J. da Silva, MSc – Ministry of Mining and Energy
Agnes M. Costa, MSc – Ministry of Mining and Energy

* Tiago de Barros Correia
Master of Science (MSc) – Economic Advisor
Ministry of Mining and Energy - Economic Advisory Office
Esplanada dos Ministérios, Bloco U, Room 818
70.065-900 – Brasília – DF
Phone: +5561 3319-5303/Fax: +5561 3319-5068/Email: tiago.correia@mme.gov.br

Abstract
Market-oriented reforms in the electricity supply industry worldwide have changed the decision investment context. Risks, such as the real need for new capacity and the return on investment, which were formerly borne by consumers or by taxpayers, now have to be faced by investors. However, even when scarcity prices efficiently reflect the tightness of supply in electricity markets, the reliability of the electric service may be jeopardized by uncertainties affecting revenue and investment perspectives. This paper uses the Brazilian experience to discuss the main issues which have to be addressed by investors and policy makers in order to improve reliability through better thermal and hydro integration and concludes that despite its remaining weaknesses, improving the energy exchange framework may remove important barriers to attract new investment and establish an adequate integration between thermal and hydro power generation.

1. Introduction

One consequence of market-oriented reforms in the electricity supply industry worldwide has been a change in the decision investment context while risks that were formerly borne by consumers or by taxpayers, now have to be faced by investors. Under the state-ownership or required cost-of-service regulatory regime, utility companies were allowed to earn a regulated rate of return above their cost of capital. Once regulators approved the construction costs of a power generating plant, the costs would be passed onto consumers through regulated electricity prices over the life of the investment, independent of fluctuations in energy prices, improving technology, and evolving supply and demand conditions. Firms, therefore, had little incentive to avoid excessive investment cost or to adopt new generation technologies (Deng and Oren, 2006).

As discussed in Araújo (2006), Brazilian reform effectively started in 1995. First, several pieces of legislation were enacted – altering the concession regime, forcing utilities to finish projects or giving up concessions, mandating open access for large consumers and independent power producers – which stimulated consortia for investing in power plants. At the same time, a study to restructure the power sector was launched, aiming to introduce competition and to divest all of distribution, transmission and generation infrastructure, excepting nuclear plants and the Brazilian half of Itaipu[1]. Also in the same year, divestment of federal assets began – before any restructuring and regulatory framework had been put in place. Furthermore, around 80% of the distribution and 50% of the generation capacity were privatized (Tolmasquim *et al.*, 2002).

[1] Itaipu was jointly built by Brazil and Paraguay at the frontier of both countries. The 1973 Itaipu Treaty established that all the energy produced by Itaipu and not used by Paraguay must be purchased by the distribution utilities of the Brazilian Southern, South-Eastern and Centre-Western regions; Itaipu energy prices are quoted in North-American dollars.

However, by the end of the 1990s, there had not been enough investments in generation and transmission expansion, culminating in a severe power rationing between 2001 and 2002. To confront the crisis, authorities developed an emergency Thermoelectric Priority Program (TPP) which foresaw the introduction of 49 thermal power plants, most fueled by natural gas (NG) (Oliveira and Marreco, 2005). It also foresaw long-term incentives (20 years) for thermal plants and guaranteed deliveries (power purchase agreement, PPA). Despite this effort, NG supply contracts priced in dollars under rigid "ship or pay" and "take or pay" clauses condemned the TPP to failure. Most of these plants did not leave the drawing-board, while others were only made feasible through partnership agreements with Petrobras (the publicly owned petroleum and NG company).

To understand the causes of the electricity shortage, let us briefly recall some of the issues which have been raised by electricity reforms, concerning uncertainty, volatility and investment in power generation. Putting it bluntly, while regulatory risks are decreasing (both from the change to a market-based context and from learning by regulators and by firms through experience) risks regarding fuel and electricity prices have claimed attention in recent years and the uniqueness of the Brazilian electrical system made this more relevant to investment decisions.

Fuel and electricity price uncertainty affects different generation technologies in distinct ways, according to their capital composition: capital-intensive technologies are more sensitive to electricity price uncertainty, fuel-intensive technologies to fuel price uncertainty (IEA, 2003). However, this is not the whole story: electricity price uncertainty may seriously affect investment in gas-fired plants in a hydro-dominated context such as that in Brazil (Araújo, 2006). This uncertainty is accompanied by substantial volatility[2] in power markets, and must be hedged against for investment to take place.

First of all, one must bear in mind the fact that the power industry in Brazil is highly dependent on the water storage capacity of the reservoirs and on the transmission capacity between regions, as roughly 91% of the power generated in Brazil, and three fourths of installed capacity, is hydroelectric. Almost 98% of the Brazilian power market is covered by an interconnected transmission network designed to enable power interchange among the North-Eastern, the Southern, and the South-Eastern/Mid-Western regions of the country. Moreover, hydropower plants are spread over a dozen major river basins, with marked differences in hydrological regimes.

Nevertheless, thermal generation is needed in order to improve the security of power supply, since reservoir level depends not only on the hydrology but also on the other uses of water, and new hydropower plants have significantly smaller reservoirs, with less firm energy relative to nameplate capacity. Unfortunately, the large share of hydropower, in the Brazilian interconnected system, means that most (80 to 90%) of the time hydropower plants are the marginal producer. Years may go bye without any thermal plant being dispatched. To change this context, many more thermal plants would have to be built, but under such conditions, investing in thermal plants is a risky business, and investors could be trapped in the "missing money" problem, where generators do not earn enough revenue to recover their investment nor attract new investment required.

In 2004 the federal government established a new institutional model for the electrical sector (two Federal Acts 10,847 and 10,848 and five Presidential Decrees 5,163; 5,175; 5,177 and 5,184). After that, the Brazilian approach to address the resource adequacy problem has been based on long term contracts resulting from specific procurement auctions for energy availability through *green field* power plants. This strategy was designed over the assumption that the existence of a fuel market for long-term contracts with enough flexibility should allow complementariness among the thermoelectric dispatched and the regulation of the reservoirs level with expressive economic gains.

In Brazil this role was usually played by diesel and oil fuel while take-or-pay clauses turn gas-fired power plants inflexible. However, an EIA (2003) report on the liquefied natural gas (LNG) industry noted that the LNG market is growing quickly and changing to more flexible contracts. These changes should produce a

[2] Volatility should not be confused with uncertainty, being rather a measure of the size and suddenness of changes. One could define volatility as the rate of change in uncertainty (as in IEA, 2003), ultimately one could have volatility without uncertainty. Whatever the precise definition, power markets present considerable volatility as an analysis of spot prices in Nord Pool, PJM or ERCOT will show.

more integrated world market for natural gas and be a new window of opportunity for a fully flexible NG power generation in Brazil.

This paper addresses the specificities of thermal generation and electricity trade in Brazil and the most recent solutions adopted for its development. Besides this section 1, which summarized the main features of the Brazilian Electricity Supply Industry, examining perspectives for investments in thermal power plants, Section 2 discusses the opportunities that have emerged from the recent changes in the NG industry and trade; Section 3 presents and discusses the electricity market in Brazil; Section 4 analyses the economic implications of greater flexibility in the NG market in the Brazilian electricity industry based on a stochastic dual dynamic programming model to determine the expected operational cost of a thermal power plant in the next 10 years; finally, Section 5 concludes, with a brief assessment of the remaining issues, that important barriers to investments in flexible NG power plants have been removed. Despite the many peculiarities of the Brazilian Electricity Supply Industry, the approach addressed to the investment adequacy problem for thermal power plants may be used to draw parallels elsewhere.

2. Evolving World Gas Market

Traditionally, NG projects are structured on long-term bilateral contracts that typically include take-or-pay and destination clauses that shift volume risk from suppliers to buyers, prevent buyers from reselling cargos to third parties and limit the impact of extreme price movements. Such was the case with the Brazilian natural gas industry organization until the 1990s, while there was a public monopoly commanded by Petrobras.

The big push on NG industry in Brazil occurred during the 90s with both the increasing offer of associated gas from national oil production and the Bolivian NG exports (GASBOL). Before that, in 1989, NG share on the Brazilian energy supply stayed around 2.5%, while its world share ranged over more than 20%. The Natural Gas National Program (NGNP) in 1987 had already tried off the Brazilian challenge to build up the third energy pillar (jointly with hydropower and biomass), despite having poor success due to the lack of instruments to put it in place (Santos *et all*, 2002). At that very same time, the 2010 Electricity Plan (PDEE 2010, Eletrobrás) considered that NG power plants were mainly restricted to substitute oil in isolated systems in the north of Brazil.

The industry reform in the 90s brought up third party access on the gas transportation grid and opened upstream for private investment, as well as established ANP – the National Regulatory Agency responsible for regulating NG transport. Distribution was set up as a monopoly regulated by the state level.

Take-or-pay and ship-or-pay long term contracts signed by power plants trying to sell in the Brazilian electricity pool market require a high level of fixed dispatch in order to face financial payments from NG delivery. This reduces NG power plants competitiveness, because Brazilian hydrothermal and national interconnected system optimize the balancing market mainly with hydropower generation (no fuel cost).

However, the world gas market is changing and becoming more flexible. LNG demand is rising faster than the overall demand for NG. For example, EIA data shows that while world consumption of NG grew at around a 2.7% compound annual rate from 2000-2004, world LNG shipments over the same period grew at a 6.2% compound annual rate. More significantly for our purposes, volumes of LNG traded in spot market have been rising, just as a variety of contracts with duration ranging from 1-2 years and 3-5 years to complement traditional 20-25 years bilateral LNG contracts or pipeline supplies (Brito and Hartley, 2007).

Changes in NG market structure include rapid growth in demand and falling transportation costs over long distances, particularly as LNG. The EIA (2004b) reports that liquefaction costs have decreased 35-50% in the past 10 years, while ship construction costs have also fallen on the order of 40% in 10 years as Korean ship builders entered the market. Furthermore, the deregulation of electricity markets and the growth of independent power producers – IPPs using NG as a fuel for generating peak load power have increased the demand for more flexible gas supply contracts.

These factors have allowed a shift in the timing of investment and contract negotiation in NG market. In the traditional gas market, producers search for potential consumers and sign long-term contracts before investing in infrastructure. In the evolving LNG market, producers invest in infrastructure before they have buyers for all their anticipated output, and buyers also invest without having firm contracts for all their expected gas needs.

These technological and market changes shall foster NG power plants in the Brazilian electricity market. Petrobras has signalized, for 2008, investments to supply up to 20 million m3/day LNG in order to make possible flexible power plants. Nowadays thermal power long-term capacity contracts customized and negotiated in the electricity pool market (CCEE) requires natural gas power plants to offer guarantee of natural gas supply, a rather burdensome requirement on generators. A possible combination of LNG flexible contracts and electricity pool contracts may offer a solution to the lack of competitiveness of natural gas power plant. Besides that, in the near future an emerging secondary market may set up conditions for further reductions in NG power plant supply exposure to risks.

In addition, electricity generators could be ready to accept some exposure to risk from potential fuel cost increase if they properly use electricity derivatives and financial tools to hedge their revenue stream over a given time period[3]. With the emergence of the electricity wholesale markets and the dissemination of risk management techniques, electricity call-and-put options have become the most effective tools available to merchant power plants and power marketers for hedging price risk. In fact, electricity generation capacities can be essentially viewed as call options on electricity, particularly when generation costs are fixed. In a simple way, electricity call-and-put options offer their purchasers the right, but not the obligation, to buy or sell a fixed amount of underlying electricity at a pre-specified strike price by the option expiration date. They have similar payoff structures as those of regular call-and-put options in financial securities and other commodities (Deng and Oren, 2006). The payoff of an electricity call option is:

$$\text{Max}\,(S_T - K, 0) \tag{1}$$

where S_T is the electricity spot price at time T and K is the strike price.

However, thermal power plants operating without high take-or-pay constrains have relevant variable costs and need a specific hedge instrument to mitigate the risk associated to the difference between the price of electricity sold by generators and the price of the fuels used to generate it. An interesting alternative is also presented in Deng and Oren (2006): *spark spread options* are cross-commodity options paying out the difference between the price of electricity sold by generators and the price of the fuels used to generate it. The amount of fuel that a generation asset requires to produce one unit of electricity depends on the asset's fuel efficiency or heat rate (MJ/kWh).

The holder of a spark spread call option written on fuel F at a fixed heat rate HR has the right, but not the obligation, to pay at the option's maturity HR times the fuel price at maturity time T and receive the price of one unit of electricity. Thus, the payoff at maturity time T of a spark spread call is

$$\text{Max}\,(S_T - HR \times F_T, 0) \tag{2}$$

where S_T and F_T are the electricity and fuel prices at time T, respectively.

Taking away the operational characteristics of a fossil fueled power generator (e.g. startup cost and ramping constraints), the per kWh benefit of owning the right to use the generator is equivalent to having 1 kWh spark spread call option with a strike heat rate matching the generator's operating heat rate. Based on this observation, it is clear that spark spread call options play important roles in hedging the price risk of the output electricity of fossil fueled power plants and further serve as key instruments in valuing those generation assets.

This cross-commodity hedge was hindered by bad regulatory rules until 2007, when the ministerial act *Portaria* 42 authorized auctions and contracts with rules compatible to the spark spread call option described above.

[3] A detailed description of a large variety of electricity derivatives, including variations of forward contracts, swaps and options, could be found in Deng and Oren (2006).

3. Electricity contracting in Brazil

According to the present Brazilian regulatory framework, distribution utilities must have their market demand fully covered by purchasing electricity through public auction within the Regulated Contracting Environment (ACR). Thus, auctions have a prominent role on contracting electricity in Brazil.

Briefly stated, auctions may be defined as a bargaining mechanism which quickly leads to the revelation of the price of a given goods, though its true value may not be revealed. To this end, they must set limits to make room for strategic actions by agents and stimulate the revelation of opportunity costs and of expectations for the future behavior of supply and demand. Additionally, the efficiency of an auction will depend on the existence of specific mechanisms and rules that increase its attractiveness and reduce possibilities for collusion, predatory competition and other forms of market power (Klemperer, 2004).

Auctions may then be understood as a space for fair competition, with rules and institutions that make competition more transparent and minimize the use of market power. The existence of an official market for electricity, operating through public auctions, may thus serve as an important instrument to consolidate the liberalization process of the Electricity Supply Industry in Brazil. Therefore, special attention should be given to the auction design. For instance, full disclosure of information (like identifying agent bids) during an auction may facilitate collusion. Thus, it might be interesting to limit information disclosure in order to reduce prospects for cartel formation. Auction rules would also simplify decision making, since it would hinder strategies that are not exclusively based upon price signals and individual preferences (Correia *et al*., 2006).

Another relevant feature of the Brazilian electricity supply industry is the dominant role of public producers. Following the privatization of distribution companies , and after the 2001 rationing, the Brazilian government effectively paralyzed the federal generation divestment process. The new institutional framework was thus designed to allow public and private firms to coexist in a competitive environment. Auctions play a central role in this design, since the existence of clear rules and a transparent trading process work as a guarantee for private firms against a possible abuse of market power by public firms.

Auctions for generation projects were then instituted in Brazil with the following purposes:

- Create a long-term contract market that generates efficient and timely price signals to guide the expansion of installed capacity.
- Ensure that the purchase of energy to supply captive consumers is done in a competitive and transparent way, leading to fair tariffs.
- Provide clear, easy to audit trading rules, in order to hinder collusion and the use of market power to manipulate prices.

The electricity procurement is made through a descending clock auction with a vertical demand curve and may take on three forms: contracts for energy from existing plants, adjustment contracts, and contracts for energy from new plants. In this paper, only the last one will be analyzed. The auctions for green field power plants are carried out five and three years before the year when that energy is needed (and must be delivered), and are known as A-5 and A-3 auctions. The former ones regard generating plants that can start operation in five years time, mostly hydropower plants; the latter ones, plants that can operate within three years, mostly thermal plants. This is intended to allow contracting a portfolio of plants that efficiently combine fixed capital costs (higher in hydro and nuclear plants) and variable costs (higher in conventional thermal plants), and permit an optimal dispatching according to the hydrological context.

Contracts signed to purchase new generators must have term between 15 and 35 years. However, if the generating costs are market-based (e.g. a NG fired merchant power plant that burns fuel at market price), selling electricity through forward contracts will expose the generator to potential fuel cost increases. Hence, two contract modalities exist, upon decision by the Ministry of Mining and Energy: contracts for energy volumes, where sellers take on all the risks, and *contracts for energy availability*, where the pool takes on the exposure to risks and passes costs and benefits through to final consumers.

Hydropower plants may have only *contracts for energy amounts* and must incorporate risk premiums in their selling prices. This approach recognizes that generators possess better pricing mechanisms for dealing with exposure to risks and that competition in long term auctions better enable the valuation of the utility of the reserve capacity required to ensure supply of a specific amount of energy.

On the other hand, thermal availability contracts are signed through an auctioning process with sellers bidding for fixed capacity payments[4], i.e. the thermal availability auction aims at clearing the premium requirement for the option contract. In order to match demand for electricity and the offer of thermal availability and hydro energy amount contracts, the auctioneer employs NEWAVE[5], mathematical programming model, to calculate an expected dispatch rate and an expected operational cost to each new thermoelectric power plant. Hence, before the bidding procedure starts the auctioneer asks the sellers to inform an *efficiency-parameter* which represents not only their heat rate but also their specific costs with logistic and trade.

This means that the Brazilian thermal availability market emulates the key features of the spark spread call options described in section 2. A Load-Serving Entity – LSE holding such a contract can purchase energy at the spot market price or at a known strike price, which includes the fuel cost at time *T*. In summary, the availability type of contract acts as price insurance, guaranteeing that the LSE will not pay more than the strike price for the energy it ensures. To obtain such insurance the LSE paid a fixed premium to the generation firm, which, on the other hand, must surrender the windfall profits it made when the spot price spiked in exchange for the fixed upfront payment. This arrangement serves as a risk-sharing mechanism which enables consumers (or the LSE representing them) to reduce their exposure to spot price risk by taking away part of the sunk-cost recovery risk from generators. Therefore, they constitute an instrument to deal with fuel and electricity price volatility, dispatch uncertainties and to confer predictability to the cash-flows of thermoelectric plants which have signed long term contracts.

4. Opportunities for Natural Gas Power Generation

To analyze whether bigger flexibility in the gas market is desirable, this work presents a comparative study between flexible and take-or-pay thermal power generation using Dual Stochastic Dynamic Programming – DSDP in a hydrothermal scheduling problem with the Brazilian power system featuresA simulation of 2000 synthetic series for the inflows of the hydroelectric system in the next 10 years allows the calculation of the average operational cost of the whole system and of the minimum electricity price required by a thermal producer to earn a given return rate. The comparative study considers, as hypotheses, that electricity consumption increases 5% a year and the generation structure described in the Electricity Decade Expansion Plan[6] – 2006/2015.

The mathematical model used, NEWAVE, is based on the assumption that an approximation of the expected-cost-to-go function can be described as a piecewise linear function and characterized without state space discretization, therefore avoiding the usual dimensionality problems associated with Dynamic Programming. This approximation of the expected-cost-to-go function is obtained from the dual solution of the problem at each stage, based on the Benders decomposition, which is able to handle stochastic variables (Martinez and Soares, 2004). A mathematical description of the equation solved by the NEWAVE is presented in the Appendix, but, briefly, the scheduling problem can be represented as:

$$z_t = Min \quad c_1 d_1 + \overline{\alpha}(x_1) \tag{3}$$

subject to

$$Ad_1 \geq b_1 \tag{4}$$

---

[4] This capacity payment scheme differs from the one established in the UK Electricity Reform through which generators received for both power generation and for the installed capacity.

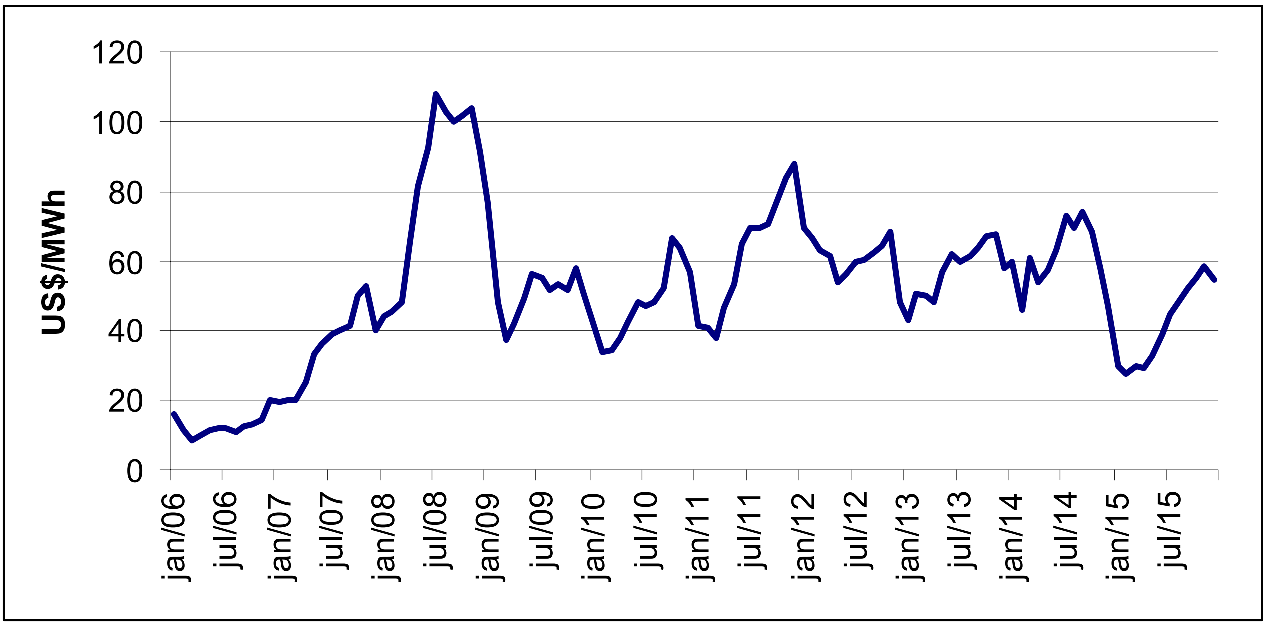
[5] The NEWAVE is an integrated resource planning model that looks ten years into the future to determine generation resource needs in terms of location and fuel mix and is the same model used to clearing price in Brazilian short-term market and in the section 4 to analyse the economic implication of greater flexibility and integration in the Brazilian natural gas market.

[6] www.mme.gov.br

where the variables d represent the decision about hydro and thermal generation, cd represents the associated cost to decision d and $Ad \geq b$ represents the constraints on system operation (hydraulic constraints, upper and lower bounds on outflows, etc.).

The NEWAVE out-put offers not only the expected total operational cost of the electrical system, but the marginal cost at each stage and at each hydro inflows scenario.

Figure 1: Brazilian Expected Average Electric Generation Marginal Costs



Source: PDEE 2006-2015

Hence, it is possible to estimate a generation rate to a given power plant and, with the equation below, the ultimate expected cost of the electricity bought from a thermo power plant with an availability contract.

$$ICB = \left(CF + \frac{\sum_{x=1}^{m} \sum_{y=1}^{c} CV\left(GT_{c,m} - GI_{c,m}\right)h_m}{120 \times 2000} \times 12 + \frac{\sum_{x=1}^{m} \sum_{y=1}^{c} CMO_{i,c,m}\left(GF - GT_{c,m}\right)h_m}{120 \times 2000} \times 12 \right) \frac{1}{GF\,h} \tag{5}$$

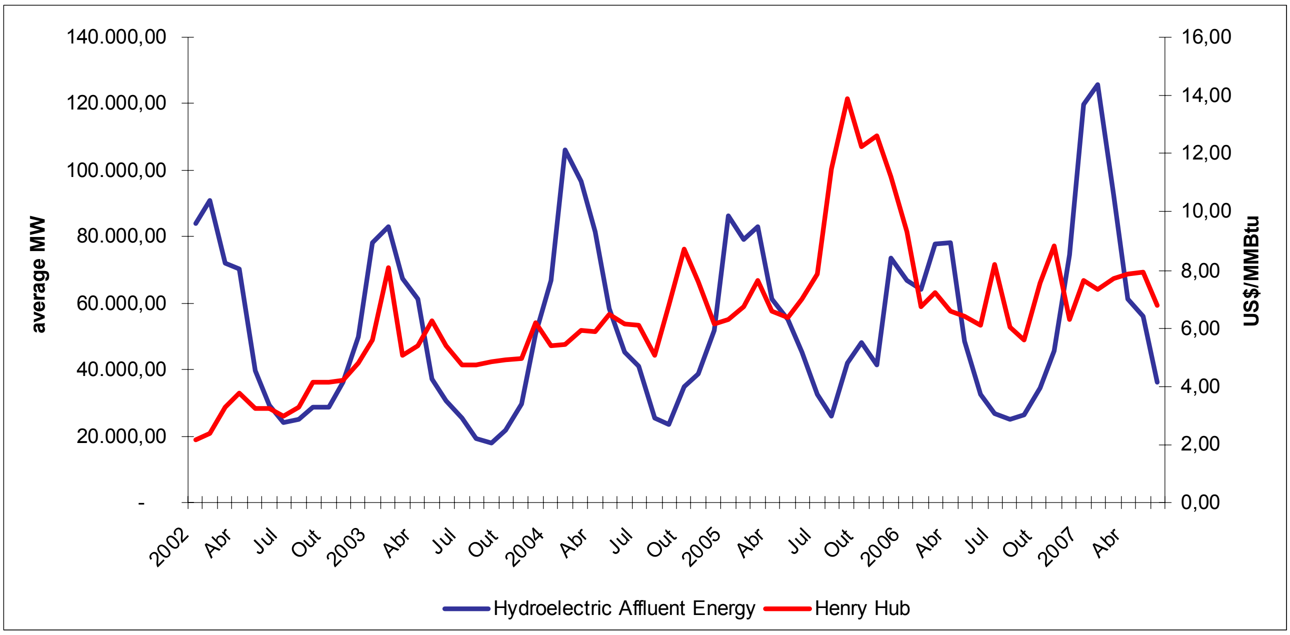
$$m = 1,\ldots,120,\ c = 1,\ldots,2000$$

where:

number of months m = 120
number of scenaiors c = 2000
ICB – the expected cost of the electricity in an availability contract including the option premium;
h – the number of hours in month m
CF – the fixed cost (US$/year)
CV – variable cost (US$/MWh)
GF – the net generation availability
$GT_{c,m}$ – the total generation at the month m in scenario c;
$GI_{c,m}$ – the inflexible generation at month m in scenario c;
$CMO_{i,c,m}$ – the marginal cost in the sub-system i at month m in scenario c.

Additionally, it is interesting to note that thermoelectric generation is expected to be bigger during the dry season, not only because water scarcity increases electricity spot prices, but because thermal generation helps to regulate the water storage in the reservoirs which reduces the price volatility. Figure 2 shows that inflows seasonality in Brazil is well defined and somehow complementary to the seasonality of the LNG prices in the North American Market.

Figure 2: Brazilian Hydroelectric Affluent Energy and NG Spot prices



Source: ONS and NYMEX (2007).

This means that there is a relevant window of opportunity for Brazil to enter in the Atlantic LGN market which could make it feasible for full flexible thermal generation in Brazil. To illustrate the possible benefits which may come up from a bigger hydro and thermal integration, consider a thermoelectric power plant with the following features:

Table 1: Power plant features

	Fuel	Energy [averageMW]	Fixed Availability Payment [US$/year]	Heat Rate	Variable Cost [US$/MWh]	Inflexibility [%]	Rate of Return [%]
Case 1	Normal Natural Gas	300	188 millions	7.75 MMBtu/MWh	50.00	80.00	15.00
Case 2	Flexible Natural Gas	300	60 millions	7.75 MMBtu/MWh	70.00	0.00	15.00
Case 3	Oil Fuel	300	50 millions	224,19 kg/MWh	250.00	0.00	15.00

Let the NEWAVE calculate the different scenarios of marginal costs. Now estimate the generation rate of each case above, and use the ICB equation to determine the expected cost of the electricity in an availability contract.

The results in Table 2 show the expected gain from a fully flexible generation, and it is so expressive that even oil fuel fired power plants are more competitive than NG power plants with strong take-or-pay clauses. In fact, a bigger flexibility in NG supply, thanks to the complementariness with the hydroelectric system, should allow an affordable electricity generation, compatible to a hydro system.

Table 2: Results

	Expected rate of generation [%]	Capacity Payment [US$/year]	Fuel Take or Pay Clause [US$/year]	ICB [US$/MWh]	Total expected cost of operation [US$/year]
Case 1	85.3	83 millions	105 millions	77.00	202 millions
Case 2	16.5	60 millions	0	55.00	145 millions
Case 3	2.8	50 millions	0	64.00	163 millions

5. Concluding remarks

The natural Brazilian hydro potential has allowed the development of a singular power system in Brazil wherein 91% of the electricity supplied in 2006 was generated by hydro power plants. Hydroelectricity is a low-priced and environmentally friendly source of energy. On the other hand, its reliability is a function of inflows and water storage capacity, implicating the existence of an inherent rationing risk that can not be avoided.

Uncontrolled exposure to market price risk can lead to devastating consequences for market agents in the restructured electricity industry and may jeopardize the reliability of the electric service. In fact, the 2001 electricity crisis in Brazil was a result of bad trading arrangements exposing investors to excessive risks.

That risk, however, can be mitigated. A thermal generation capacity integrated to the power system and operating as a complementary source of energy can improve the total firm energy and increase the system reliability. Additionally, with a centralized operation, it is possible to optimize the thermal and hydro power plants dispatched to minimize the total operational cost. Section 4 showed the economic benefit that can be achieved with an integration based on fully flexible NG power plants.

In the Brazilian power systems, this economic benefit is particularly expressive because of the great water storage capacity and the complementariness between Brazilian rain regime and the LNG price seasonality in the New York Mercantile Exchange – NYMEX.

The results obtained in this study lead us to conclude that investments in fully flexible thermal power plants in Brazil are quite feasible. *Portaria* 42 has made cross-commodities risk management between fuel and electricity prices possible. These contracts emulate options contracts and work as financial price insurance and serve as a risk-sharing mechanism which enables thermo power producers to reduce their exposure to fuel and electricity price volatility, dispatch uncertainties and to confer predictability to the cash-flows of thermoelectric plants which have signed long term contracts.

In fact, availability contracts play an important role in establishing price signals, providing price discovery, facilitating effective risk management, inducing capacity investments in generation, and enabling capital formation. However, the exiting legal and financial instruments may not be sufficient to make a relevant LNG trade between Brazil, USA, UE and other LNG markets possible. Petrobras anounced investments to supply Brazilian NG power plants with up to 20 million m3/day does not include storage capacity. This means that Brazilian LNG market will have a delivery time gap because of the travel time needed to ship LNG from foreign markets.

This problem could be addressed either by changing the dispatch scheduling methodology to allow ONS to anticipate the generation order to fully flexible NG power plants or by developing an electricity derivatives market. The first alternative seems to be preferred by thermal generators and NG suppliers, since it is easier and cost and risk free to them, but that option implicates in changing the auction's ICB formula, turning it even more discretionary. The second alternative could be more complex, but it is certainly more interesting.

In fact the storage capacity of the Brazilian hydro power plants could be used, through specific derivative contracts, by the thermal generators to remove the risk of a dispatch order without fuel. These contracts could provide adequate economic signal to investment in both thermal and hydro power plants with reservoir, but that needs more integration between markets and the development of new derivatives. Actually, the recent energy exchange framework improvement has removed important investment barriers and established an adequate incentive to fully flexible thermal generation in Brazil, however the better integration between hydro and NG power generation is still improbable.

6. Mathematical Appendix

Section 4 analyses the economic implications of greater flexibility of the NG market in the Brazilian electricity industry based on NEWAVE, a stochastic dual dynamic programming model, to determine the expected operational cost of a thermal power plant in the next 10 years. The equation to represent this hydrothermal scheduling problem is described as following:

$$\mathrm{z_t} = \mathrm{Min} \sum_{k \in NS} \sum_{j \in NUTk} CT_j GT_{t,j} + \frac{1}{1+\beta} \alpha_{t+1}$$

subject to

Hydro balance constrains

$$EA_{t+1}(k) = FDIN_t(k) EA_t(k) + FC_t(k) EC_t(k) - GH_t(k) - EVT_t(k) - EVM_t(k)$$
$$- EVP_t(k) - EM_t(k) - EDVC_t(k) \qquad k = 1,\ldots, NS$$

Demand constrains

$$GH_t + \sum_{j \in NTUk} GT_{t,j} + \sum_{i \in \Omega k} \left(F_{t,i,k} - F_{t,k,i} \right) + DEF_{t,k} - EXC_t(k) = D_{t,k} - EVM_t(k)$$
$$- EFIO_t(k) - \sum_{j \in NUTk} GTMIN_{t,j} - EDVF_t(k) \qquad k = 1,\ldots, NS$$

Thermoelectric generation bounds

$$0 \le GT_{t,j} \le \overline{GT}_{t,j} \qquad \forall\, j \in NUT_k,\ k = 1,\ldots, NS$$

Interchange capacity bounds

$$\left| F_{t,i,k} \right| \le \overline{F}_{t,i,k} \qquad i = 1,\ldots, NS,\ k = 1,\ldots, NS$$

Hydro reservoir capacity bounds

$$0 \le FDIN_{t+1}(k) EA_{t+1}(k) \le EAMAX_{t+1}(k) \qquad k = 1,\ldots, NS$$

Hydroelectric capacity bounds

$$GH_t(k) + EFIO_t(k) + EVM_t(k) \le GHMAX_t(k) \qquad k = 1,\ldots, NS$$

Operational bounds

$$EAMIN_{t+1}(k) \le FDIN_{t+1}(k) EARM_{t+1}(k) \le EAVEMAX_{t+1}(k) \qquad k = 1,\ldots, NS$$

Cost-to-go function

$$\alpha_{t+1} - \sum_{k \in NS} \pi EA_{1,t+1}(k) EA_{t+1}(k) \ge \delta_{1,t+1}$$

…

$$\alpha_{t+1} - \sum_{k \in NS} \pi EA_{q,t+1}(k) EA_{t+1}(k) \ge \delta_{q1,t+1}$$

Fictitious subsystems constrains

$$\sum_{i \in \Omega k} \left(F_{t,i,k} - F_{t,k,i} \right) = 0 \qquad k = 1,\ldots, NFIC$$

Where:

z_t	Expected cost-to-go value from stage t to decision horizon T
β	Discount rate
α_{t+1}	Expected decision cost value from stage t to stage t+1
$EA_t(i)$	Hydroelectric stored energy in the subsystem I at stage t
$EAMAX_t(i)$	Hydroelectric stored energy upper bound in the subsystem i at stage t
$GH_t(i)$	Hydroelectric controllable energy generated in the subsystem i at stage t
$GHMAX_t(i)$	Hydroelectric generation upper bound in the subsystem i at stage t
$EVT_t(i)$	Hydroelectric spillage in the subsystem i at stage t
$EXC_t(i)$	Hydroelectric energy surplus in the subsystem i at stage t
$EC_t(i)$	Hydroelectric controllable affluent energy in the subsystem i at stage t
$EFIO_t(i)$	Hydroelectric uncontrollable affluent energy in the subsystem i at stage t
$EVP_t(i)$	Hydroelectric evaporated energy in the subsystem i at stage t
$EM_t(i)$	Hydroelectric dead volume t $EDVF_t(i)$o fill the reservoir in the subsystem i at stage t
$EVM_t(i)$	Hydroelectric affluent energy lower bound in the subsystem i at stage t
$GT_t(j)$	Thermoelectric energy generated at plant j in the subsystem i at stage t
$\overline{GT}_t(j)$	Thermoelectric energy upper bound of the plant j in the subsystem i at stage t
$GTMIN_t(i)$	Thermoelectric energy lower bound of the plant j in the subsystem i at stage t
$F_t(i,k)$	Energy interchanger from subsystem i to subsystem k at stage t
$\overline{F}_t(i,k)$	Energy interchanger upper bound from subsystem i to subsystem k at stage t
$EDVC_t(i)$	Hydroelectric bypass energy to be decreased to the controllable energy in subsystem i at stage t
$EDVF_t(i)$	Hydroelectric bypass energy to be decreased to the uncontrollable energy in subsystem i at stage t
$D_t(i)$	Energy demand in subsystem i at stage t
$DEF_{t.i}$	Energy deficit in subsystem i at stage t
CT_j	Thermoelectric cost associated at the plant j
Ω_i	Set of the subsystems directly connected
NS	Number of real subsystems
$NFIC$	Number of fictitious subsystems
$EAMIN_t(k)$	Hydroelectric energy stored lower bound in subsystem k at stage t begin
$EAVEMAX_t(k)$	Hydroelectric energy stored upper bound in subsystem k at stage t begin
$FDIN_t(i)$	Correction factor for the energy stored in subsystem i at stage t
$FC_t(i)$	Correction factor for the controllable energy in subsystem i at stage t
q	Segment number of the cost function
$\pi EA_{t+1}(i)$	Derivative of the objective function z_t relative to the hydroelectric energy stored subsystem i at stage t
δ_{t+1}	Constant term of the linear constrain

7. References

Araújo, J. L. R. H.; Costa, A. M. A.; Correia, T.; Melo, E. (2007), Energy contracting in Brazil and electricity prices. IAEE International Conference, Wellington, New Zealand, 18-21 February 2007.

Araújo, J. L. R. H. (2006), The case of Brazil: Reform by trial and error? in Sioshansi and Pfaffenberger (eds.), Electricity Market Reform – An International Perspective (Elsevier, 2006), Amsterdam.

Brito, D. L. & Hartley, P. R., (2007), Expectation and the evolving gas market. *The Energy Journal; 28 (1).*

Correia, T. B.; Melo, E.; Costa, A. M. (2006), Análise e avaliação teórica dos leilões de compra de energia elétrica proveniente de empreendimentos existentes no Brasil. *Revista EconomiA/ANPEC*, *7 (3):* 607–627.

Deng, S.J. and Oren, S.S. (2006), Electricity derivatives and risk management. *Energy; 31:* 940-953.

Energy Information Administration (EIA), (2003), World LNG Market Structure. Available at http://www.eia.doe.gov/oiaf/analysispaper/global/lngindustry.html.

International Energy Agency (IEA), (2003), "Power Generation Investment in Electricity Markets", OECD/IEA ISBN 92-64-1055-65, Paris.

Klemperer, P. (2004). Auctions: Theory and Practice. Princeton University Press.

Oliveira, R. G. & Marreco, J. M. (2005), Natural gas generation in Brazil: New window of opportunity? *Energy Policy; 34*: 2361-2372.

Tolmasquim, M., Oliveira, R., Campos, A., (2002), As empresa do setor elétrico – Estratégias e performance, Rio de Janeiro, Cenergia/UFRJ.